THE RWANDA GRID CODE

Preamble

1 of 7 Code Documents

Version 1.0

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Enquiries: RURA, Rwanda
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1 Introduction

(1) The Preamble document provides the industry context for the Rwanda Grid Code and its various components. It also contains detailed definitions and acronyms of the terms used in the Grid Code documents.

2 Policy and Structure

2.1 Policy Objectives for the Rwandan Electricity Industry

(1) The main policy objectives of the Electricity Supply Industry (ESI) are the following:

(a) Address challenges in projects currently under implementation and develop plans to successfully complete them;

(b) Secure the necessary funding for planned electricity projects;

(c) Involvement of local communities (to the extent possible) in developing electricity projects;

(d) Enhanced access to electricity, particularly in rural areas;

(e) Reduction in the cost of electricity (least cost electricity Generation mix and network development);

(f) Diversification in sources of electricity supply;

(g) Encourage increased participation by the local and foreign private sector in the electricity industry;

(h) Enhanced regional cooperation in electricity to reduce overall costs and improve security of supply

(i) Clarification of roles within public sector structures and development of skills in planning, procurement, and transactions’ negotiation;

(j) Development of the legal, regulatory, institutional and financial framework for rapid development of the electricity industry.

(2) In addition, the introduction of privatisation and competition within the electricity industry is a long-term policy.

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### 2.2 Institutional Overview of the Electricity Industry

(1) Figure 1 summarises key institutions and roles in the Rwanda electricity industry

<table>
<thead>
<tr>
<th>Name</th>
<th>Entity</th>
<th>Ministry</th>
<th>GOR Body</th>
<th>Public</th>
<th>Private</th>
<th>Main Roles and Functions in the ESI</th>
</tr>
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</table>
| MoE        | ☑      | ☐        | ☑        | ☐      |         | 1. Overall coordination of the energy sector  
2. Develop institutional and legal frameworks  
3. National electricity policy formulation  
4. Energy planning, strategies and master plans  
5. Regional integration and harmonisation  
6. Human resource capacity building  
7. Procurement  
8. Supervise and monitor other government agencies in implementation of policies, strategies and master plans  
9. Work with government agencies to assist private investors |
| The Authority | ☑      | ☑        | ☑        | ☐      |         | 1. Regulation of the electricity licensing  
2. Tariff setting  
3. Facilitate private sector participation  
4. PPP development  
5. Quality of Supply standards and performance indices  
6. Licensee compliance monitoring |
| NSA        | ☑      | ☑        | ☐        | ☐      |         | 1. Define and set national industry standards  
2. Ensure products adhere to national standards  
3. Ensure trade equity by enforcing standardisation  
4. Approve products in public tenders  
5. Setup a national certification/accreditation system  
6. Collaborating with other relevant establishments with similar responsibilities at regional/international level |
| RDB        | ☑      | ☑        | ☑        | ☐      |         | 1. Fast track PPP development  
2. Promote local and foreign direct investment  
3. Promote exports to regional/international markets  
4. Carry out and monitor privatisation programmes  
5. Facilitate private business setup  
6. Participate in policy/strategy initiation and implementation  
7. Advise government on fast track development |
| NEP        | ☑      | ☑        | ☑        | ☐      |         | 1. Investment management & implementation  
2. Design, finance, build and operate/maintain power plant i.e. GenCo  
3. Operate the Interconnected Power System (IPS) of Rwanda i.e. System Operator (SO) |
<table>
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|      |          |          |        | 4        |
|      |          |          |        | Design, finance, build and operate/maintain transmission assets i.e. TransCo |
|      |          |          |        | 5        |
|      |          |          |        | Design, finance, build and operate/maintain distribution assets i.e. DisCo |
|      |          |          |        | 6        |
|      |          |          |        | Buy and sell electricity locally/internationally i.e. TradeCo and international TradeCo |

**Figure 1: Summary of the current key Institutions and their Roles and Responsibilities in the Rwandan ESI**

### 2.3 Current Electricity Industry Structure

1. The current structure of all the bodies involved in the *Electricity Supply Industry (ESI)* in Rwanda is shown in Figure 2.

2. It is important to note that the *Transmission System Operator (TSO)* and *System Operator (SO)* functions currently reside inside the *NEP*. This results in the *NEP* owning *Generation, Transmission* and *Distribution* as well as dispatching all *Generation* and operating the networks. In order for full transparency and independence as well as for the *Authority* to regulate the functions of the ESI accurately, these functions should either:

   a. Be financially ringfenced inside *NEP* to ensure no cross-subsidisation across the value chain (*Generation, Transmission* and *Distribution*, system operation as well as network planning and development).
Energy Sector Working Group:
- MININFRA, MINECOFIN, MINCOM, MOD, MINIRENA, MINALOC, RDB, REMA, MINEDUC, MOH
- Various development partners (World bank, ADB, EU, BTC, GTZ, BADEA, SFD, OFID)
- Private sector companies

Various development partners (World bank, AfDB, EU, BTC, GTZ, BADEA, SFD, OFID)

Private sector companies

Key:
- Competition Authority
- Industry entities
- Industry entities (public/private)
- Other entities
- Formal control/jurisdiction
- General interaction/relationship
(3) The interactions between the main functional bodies the Rwandan ESI are illustrated in Figure 3.

![Figure 3: Current Rwandan functional ESI Structure](image)

(4) The above figure shows that the National Energy Provider (NEP) is currently responsible for:

(a) **Generation** i.e. NEP (G)
(b) **Transmission** i.e. NEP (T)
(c) **Distribution** i.e. NEP (D)
(d) Purchasing of power from NEP (G) and GenCos (IPPs) i.e. NEP (Commercial)
(e) Trading of electricity via NEP (Commercial) with regional entities e.g. SINELAC and Eastern Africa Power Pool (EAPP) member utilities.
(f) Safe, efficient and reliable operation of the Transmission and Distribution system i.e. the System Operator (SO).
(g) Selling of electricity to Customers via NEP (Commercial).

### 2.4 Electricity Industry Reform

(1) For a number of reasons the GOR have embarked on an electricity market reform process to allow private entities to fulfil a much bigger role in the electricity industry. The Electricity Law governing the electricity industry in Rwanda provides a deeper insight into the future electricity market structure. Figure 4 interprets the intended future industry for domestic transactions.
The above figure shows:

(a) The following activities in the electricity industry require a license from the Authority:
   - Generation
   - Transmission
   - Trading
   - Distribution

(b) Multiple Generators (GenCos) are allowed, including NEP (G)

(c) Multiple Transmitters (TransCos) are allowed, including NEP (T)

(d) Multiple Distributors (DisCos) are allowed, including NEP (D)

(e) Multiple Traders (TradeCos) are allowed, including NEP (Trader)

(f) TradeCos, including NEP (Trader), can buy electricity from any GenCo, including NEP (G)

(g) TradeCos, including NEP (Trader), can sell electricity to any Large and/or Small Customers.

(h) Large and/or Small Customers can buy electricity from any licensed TradeCo, including NEP (Trader).

(i) The new market structure allows for greater competition between GenCos and TradeCos and more choice for Large Customers.
(3) The Electricity Law also allows for Participants to apply for an International Trading License (to become and International TradeCo). This license will grant the holder the opportunity to procure power and ancillary services for export and/or import. The market structure inclusive of the above mentioned International Trading License is slightly more complex and is shown in Figure 5.

![Figure 5: Intended functional Rwanda ESI structure for domestic and international transactions](image)

(4) The new market structure places new demands on the ESI including:

(a) Appropriate and transparent technical and operational standards.

(b) Incorporation of bilateral trading arrangements.

(c) Energy wheeling across networks implying fair and non-discriminatory network access and prices.

(d) Network congestion management.

(e) Energy balancing services

(f) Ancillary services

(g) Independence/ring-fencing of the various NEP functions (GenCo, TransCo, DisCo and SO/TSO)
Many of these issues can be addressed through suitable legislation including this Grid Code and other regulatory rules/standards.

## Authority

### 3.1 Regulations

(1) The Grid Code derives its authority from the following regulations.

(a) Electricity license to produce (generate) electricity.

(b) Electricity license to transmit electricity.

(c) Electricity license to distribute electricity.

(d) Electricity license to trade (buy and sell) electricity both locally and internationally.

### 3.2 Legislation

(1) The various electricity licenses derive their legal authority from the following laws.

(a) Law N°21/2011 of 23/06/2011 Governing Electricity In Rwanda (The Electricity Law)

(b) Law N°39/2001 of 13/09/2001 Establishing an Agency for the Regulation of Certain Public Utilities (RURA Law)

(c) Applicable regulations and legislation released by the Authority from time to time

### 3.3 Applicability

(1) All Licensees are required to comply with the provisions of the Electricity Law, their respective granted Licences as well as the approved Grid Code and applicable legislation and regulations. Any breach could result in the sanctioning, suspension or withdrawal of the applicable License.

## Grid Code

### 4.1 Definition
(1) The term *Grid Code* is widely used to refer to a document (or set of documents) that legally establishes technical and other requirements for the connection to and use of an *IPS* in a manner that ensures reliable, efficient, economic, safe and on-going operation of the *IPS*.

4.2 *Objectives*

(1) The fundamental function of a *Grid Code* is to establish the rules and procedures that allow all *Participants* to use the *IPS* and to permit the *IPS* to be planned and operated:

   (a) Safely,
   
   Reliably,
   
   Efficiently,
   
   Economically.

(2) In order to achieve this goal, the *Grid Code* must:

   (a) Be objective,
   
   Be transparent,
   
   Be non-discriminatory,
   
   Be consistent with Government policy,
   
   Define the obligations and accountabilities of all the *Participants*
   
   Specify minimum technical requirements for the *Transmission system*
   
   Specify minimum technical requirements for the *Distribution system*
   
   Ensure that the relevant *Information* is made available to all *Participants* as/when required

(3) The *Grid Code* provides the following assurances:

   (a) To the *Authority*, the assurance that the *Licensees* operate according to the respective *License* conditions.

   To *Customers*, the assurance that *Licensees* operate transparently and provide non-discriminatory access to their defined services.

   To *Licensees*, the assurance that *Customers* will honour their mutual *Grid Code* obligations and that there is industry agreement on these.
4.3 Grid Code Overview

(1) The Grid Code covers a range of technical, operational, commercial and governance issues. In order to address these comprehensively in a structured way, the Grid Code is broken down into a number of “sub-codes”. These are:

(a) The Preamble;
(b) The Governance Code;
(c) The System Operations Code (including elements of Scheduling and Dispatch);

The Network Code;
The Metering Code;
The Information Exchange Code;
The Network Tariff Code

(2) The key aspects of each of these are set out briefly below.

a. The Preamble provides the context for the Grid Code and its various subsections. It is also the single document in the Grid Code that contains detailed definitions and acronyms of all relevant terms and abbreviations used in the Grid Code documents.

b. The Governance Code sets out how the Grid Code will be maintained. It describes the process that will be followed to update the Grid Code to improve safety, reliability and operational standards. It sets out how Grid Code Participants can influence the amendment process and defines who has the authority to recommend and ultimately approve and enforce the changes. In addition the document also explains oversight and compliance requirements that need to be observed by all Grid Code Participants.

c. The System Operations Code sets out the responsibilities and roles of the Grid Code Participants as far as the operation of the IPS is concerned. It also sets out the responsibilities and roles of the Grid Code Participants as far as the scheduling and dispatch of the IPS is concerned. It addresses, amongst other things:
i. Reliability, security and safety;

ii. Field operation, maintenance and maintenance co-ordination / outage planning.

iii. Operations planning;

iv. Scheduling and dispatch operation actions;

v. Ancillary Services;

vi. Operational Authority

vii. Operating procedures

viii. Operation liaison

ix. System frequency control

x. Independent actions required and allowed by Participants;

xi. Voltage control

xii. Fault and incident reporting

xiii. Commissioning responsibilities

xiv. Risk of trip

xv. Maintenance co-ordination and outage planning

xvi. Communication of IPS operational conditions

xvii. Telecontrol

d. The Network Code focuses on the technical requirements and standards of the Interconnected Power System (IPS). It is broken down into sections defining:

i. Off-grid conditions

ii. Network connection processes

iii. General connection conditions (for Generators (GenCos), Embedded Generators (EGs), Transmitters (TransCos), DisCos and Customers,

iv. Technical design requirements applicable to TransCos and DisCos,

v. Electrical protection requirements for TransCos and DisCos,

vi. Network planning and development,
vii. Other network services
viii. Network maintenance requirements.

e. The **Metering Code** ensures a *Metering* standard for all current and future *Grid Code Participants*. It specifies *Metering* requirements to be adhered to, and addresses levels of responsibility. The code sets out provisions relating to:

i. Application of the **Metering Code**

ii. Provisions of the **Metering Code**

iii. **Metering Point** responsibilities

iv. **Metering Installation** requirements

v. **Metering Apparatus** maintenance

vi. **Metering Apparatus** Access

vii. **Data validation and verification**

viii. The **Metering database**

ix. Testing of **Metering Installations**

x. **Metering** database inconsistencies

xi. Access to **Metering Data**

xii. Customer queries on **Metering** integrity and data

f. The **Information Exchange Code** defines the obligations of parties with regard to the provision of *Information* for the implementation of the *Grid Code*. The *Information* requirements as defined for the *Grid Code Participants* are necessary to ensure the non-discriminatory access to the *IPS* and the safe, reliable provision of *Transmission* and *Distribution* services. The Information Exchange Code contains the following:

i. *Information* exchange interface

ii. Planning *Information*,

iii. Operational *Information*, and

iv. Post-dispatch *Information*

v. Confidentiality of information.
g. The **Network Tariff Code** sets out the objectives and principles of *Transmission* and *Distribution* service pricing, application of charges and fees and the procedure to be followed in applications by *licensees* to change revenue requirements, tariff levels or tariff structure. It covers the:

i. Authority of RURA to regulate tariffs/charges

ii. Applicability and objectives of the *Network* Tariff Code

iii. Principles for the regulation of income

iv. Approach to the determination of tariff structures and levels

v. Procedure for RURA Approval and Tariff Change Notifications

5 **Definitions and Acronyms**

(1) This glossary of definitions and acronyms is set out taking cognisance of the international and regional context, recognising that some terms are, however, only used in the Rwandan market.

(2) All Definitions and Acronyms listed below apply to the complete set of *Grid Code* documents.

5.1 **Definitions**

(1) **Active Energy** - Active Energy means the electrical energy produced, flowing or supplied by an electrical circuit during a time interval, and being the integral with respect to time of active power, measured in units of Watt-Hours or multiples thereof.

(2) **Active Power** - Instantaneous power derived from the product of voltage and current and the cosine of the voltage phase angle measured in units of Watts and multiples thereof.

(3) **Amendment** – A change to any part of the *Grid Code* approved by the Authority following the appropriate procedures outlined in the *Governance Code*.

(4) **Ancillary Services** - Services supplied to a *Transmission* company by *Generators*, *DisCos* and/or *end-use Customers* necessary for the reliable and
secure transport of power from Generators to DisCos and Customers. Ancillary services maintain the short-term reliability of the IPS and include the various types of reserves, black start, reactive power, unit islanding etc.

(5) **Apparatus** - An item of equipment, in which electrical conductors are used, supported or of which they form a part and includes meters, lines, cables and appliances used or intended to be used for carrying electricity for the purpose of supplying or using electricity.

(6) **Area Control Error (ACE)** – The instantaneous difference between net actual and scheduled interchange, taking into account the effects of frequency bias including correction for metering error.

(7) **Authority** – See *Regulatory Authority*

(8) **Automatic Generation Control (AGC)** - Equipment that automatically adjusts a Control Area's Generation to maintain its interchange schedule plus its share of frequency regulation.

(9) **Automatic Load Shedding Scheme** – A load shedding scheme utilised by the TSO to prevent frequency collapse and to restore the balance between Generation output and Demand.

(10) **Automatic Voltage Regulator (AVR)** - The continuously acting automatic equipment controlling the terminal voltage of a Synchronous Generating Unit by comparing the actual terminal voltage with a reference value and controlling by appropriate means the output of an Exciter (or source of the electrical power providing the field current of a synchronous machine), depending on the deviations.

(11) **Auxiliary Supply** - Supply of electricity to auxiliary systems of a generating unit or substation equipment.

(12) **Black Start Capability** - The provision of generating equipment that, following a total system collapse (black out), is able to:

(a) Start without an outside electrical supply and
(a) Energise a defined portion of the Transmission System 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 Transmission System upon instruction of the TSO.

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

(14) **Co-Generator** – An entity who operates and/or owns a Generating Unit that as part of its core design utilises waste energy, produces other usable energy in addition to electricity and/or is renewable fuel based which is a co-product of an industrial production process. A Co-Generator typically connects to the Distribution System (an Embedded Generator) but can connect to the Transmission System in selected cases (a Generator).

(15) **Competition Authority** – An Authority setup to investigate, control and evaluate anti-competitive behaviour, restrictive business practices, abuse of dominant positions and mergers in various industries. In this instance, more specifically in the ESI in order to achieve equity and efficiency in the economy.

(16) **Connection Agreement** – A bilateral agreement made between a Distribution Licensee, Transmission Licensee or TSO and a Participant (domestic/international) setting out the terms and conditions relating to the use of a Connection Point and other specific provisions in relation to that connection, including inter alia the following:

(a) **Active Power and/or Active Energy transfer**

(b) **Reactive Power and/or Reactive Energy transfer**

(c) **Quality of Supply**

(d) **Ancillary Services**

(17) **Contingency** – An unexpected incident, failure or outage of an interconnected system component, such as a Generating Unit, Transmission line, circuit breaker, switch or other electrical element. A Contingency may also include multiple components, which are related by situations leading to simultaneous component outages.
(18) **Control Area** – An area comprised of an electric system or systems, bounded by interconnection metering, capable of regulating its *Generation* in order to maintain its interchange schedule with other electric systems or Control Areas and to contribute its frequency bias obligation as required. A *Control Area* adheres to the minimum requirements for a *Control Area* as defined in the Eastern Africa Power Pool (EAPP) Operating Rules.

(19) **Cross-border electricity trade** – means trading in electricity between two states sharing a common border through an interconnector power line, but linked through a power pool which involves export or import of energy between the states.

(20) **Customer** – See *End-use Customer*.

(21) **Data** - See *Information*.

(22) **Data Terminal Equipment (DTE)** – A communication device that can control data flow and is capable of generating or terminating data.

(23) **Day** - A period of 24 consecutive hours commencing at 00:00 and ending at 24:00 Rwanda Standard Time.

(24) **Demand** – an instantaneous consumption of electric power from any *Participant*.

(25) **Demand Side Management (DSM)** – the ability of a *Consumer* to willing reduce consumption on instruction from the *System Operator* or via under frequency relays. This service may be compensated for as an *Ancillary Service*.

(26) **Derogation** – A waiver issued by the *Grid Code Review Panel* to suspend a *Participants* obligations to implement or comply with a provision or provisions of the Grid Code.

(27) **DisCo** – Refers to general (non-specific) *Distributor*
(28) **Dispatch Instruction** – An instruction to a Generator or Consumer to change the electrical output of the Generator or Consumer’s consumption.

(29) **Dispute** – Any difference controversy between the Grid Code Review Panel and a Participant in connection with or arising from the interpretation, implementation or breach of any provision in the Grid Code.

(30) **Distribution** – Means the transportation of electric energy and power by means of medium voltage to low voltage lines, facilities and associated meters, including the construction, operation, management and maintenance of such lines, facilities and meters.

(31) **Distribution area** – the area within which a Distribution licensee has the exclusive right to provide service to any Customer in the area that the Distribution licensees licence allows.

(32) **Distribution Licensee** – a licensee authorised to undertake Distribution activities in accordance with the specific rights laid out in the issued licence.

(33) **Distribution Metering Administrator** – A Participant that is responsible for all Distribution tariff metering installation, maintenance and operations e.g. DisCo.

(34) **Distribution System** – An electricity network consisting of assets (including: substations, transformers, cables, lines and associated equipment) which are operated at Medium Voltage and/or Low Voltage.

(35) **Distributor** – A licensed entity that, subject to condition of its licence, owns operates and maintains a Distribution system.

(36) **EAPP Interconnected Transmission System** – The Transmission system in Eastern Africa consisting of two or more individual National Systems or Control Areas that normally operate in synchronism and are physically interconnected via Transmission facilities.

(37) **EAPP Interconnection Code** – The Code by which all EAPP member countries and EAPP member utilities are required to adhere to. It outlines the
framework for the successful pooling of Generation, rules for coordinated system planning and operation, agreed principles and procedures for dispute settlements and arrangements for equitable sharing of benefits in the Eastern African region.

(38) **EAPP Sub-Committee on Planning** – the entity established under EAPP governance responsible for coordination of *Electricity Master Plans* and development programs of EAPP Members.

(39) **Economic regulation** – an intervention to modify, as and when deemed appropriate, the economic behaviour of a regulated supplier aimed at narrowing choices in certain areas including prices, rate of return and methods of procurement.

(40) **Electricity Law** – The Rwandan Electricity Law No 21/2011.

(41) **Electricity Master Plan** – a planning document prepared by the *Minister* and updated on an annual basis by the *System Operator*, dealing with indicative medium and long-term plans for the expansion of the *Transmission system* to cater for expected *Generation* and demand developments.

(42) **Electricity Supply Industry (ESI)** – also referred to as *Electricity Industry* refers to the industry involving electricity production (*Generation*), *Transmission*, *Distribution*, *trade*, *supply* and regulation.

(43) **Embedded Generator (EG)** – A legal entity operating licensed *Embedded Generating Units*.

(44) **Embedded Generating Unit (EGU)** - A type of *Generating Unit*, other than a *Co-Generator*, that is not directly connected to the *Transmission System*.

(45) **Emergency** - A situation where *Transmission* or *Distribution licensees* have an unplanned loss of facilities, or another situation beyond their control, that impairs or jeopardises their ability to supply their system demand.

(46) **Emergency outage** - An outage when plant has to be taken out of service so that repairs can immediately be affected to prevent further damage or loss.
Emergency Transfer Capability – the total amount of power above the net contracted purchases and sales which can be scheduled between two control areas with assurance of adequate system reliability for transfers over the transmission network for periods up to several days, based on the most limiting of the following constraints:

a. All transmission loadings initially within long-term emergency ratings and voltages initially within acceptable limits;

b. IPS capable of remaining stable after absorbing the initial power swings and upon the loss of any single Transmission circuit, transformer, bus section, or Generating Unit; and

c. All transmission loadings within their respective short-time emergency ratings and voltages within emergency limits after the initial power swings following the disturbance but before system adjustments are made (and in the event of a permanent outage of a facility, transfer schedules may need to be reviewed).

End-use Customer - Users of electricity above 1 kV (demand and/or supply). An End-use Customer can be a Large Customer and/or Small Customer.

Energy Management System (EMS)- usually a system of computer-aided tools used by operators of electric utility grids to monitor, control, and optimise the performance of the Generation and/or Transmission system. The monitor and control functions are known as SCADA; the optimization packages are often referred to as “advanced applications”.

Exemption – A provision made by the Authority for a Participant who does not need to comply with a section/s of the Grid Code. The appropriate procedure outlined in the Governance Code should be followed before an Exemption is approved and granted.

Expert - A well-qualified person with broad proven experience appointed by RURA or the GCAC to express his/her opinion or give advice on issues concerning the Grid Code.
(52) **Excluded services** – Services requested by *Customers* that are excluded from the regulated activities and funded directly by the *Customer*.

(53) **Force Majeure** - Causes beyond the reasonable control of and without the fault or negligence of the *Participant* claiming *Force Majeure*. It shall include failure or interruption of the delivery of electric power due to causes beyond that *Participants* control, including Acts of God, wars, sabotage, riots, actions of the elements, civil disturbances and strikes.

(54) **Firm supply** - is defined such that if any parallel circuit is out for maintenance or on an unplanned outage, the supply can still be supplied via the remaining parallel circuit in accordance with the technical provisions laid out in the Grid Code.

(55) **Forced outage** - An outage that is not a *Planned Outage*.

(56) **Frequency** - The number of oscillations per second on the AC waveform.

(57) **GenCo** – Refers to general (non-specific) *Generator*.

(58) **Generation licensee** – a *licensee* authorised to undertake electricity *Generation* services.

(59) **Generation** – the production of electric energy and power from any primary source of energy.

(60) **Generating Unit** - A device used to produce (generate) electrical energy.

(61) **Generator** - A legal entity operating licensed *Generating Units*.

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

(63) **Governor droop Characteristic** - the ratio of the per unit steady state change in speed, or in *Frequency* to the per unit steady state change in power output.
(64) **Grid Code** – the document (or set of documents) that legally establishes technical and other requirements for the connection to and use of the *IPS* by *participants* in a manner that ensures reliable, efficient, safe and ongoing operation of the *IPS* in line with the technical and procedural rules and standards issued by the *Authority*.

(65) **Grid Code Participant** - Any legal entity that falls under the mandate of the *Grid Code* and registered as set out in the *Grid Code* Governance Code.

(66) **Grid Code Advisory Committee (GCAC)** – The panel established by RURA in accordance with the *Governance Code* charged with the provision of expert technical advice on Grid Code matters as well as the review of the operation, consultative stakeholder process and revision of the *Grid Code*.

(67) **High Voltage (HV)** – AC or DC voltage of the amount equal or above seventy thousand volts plus or minus ten per cent.

(68) **Incident** - An event which is not part of the standard operation of the *Transmission System* or the *Distribution System* and which causes or may cause disruption to or a reduction in the quality of services or impact on people health or plant life and cost.

(69) **Incident Report** – A written document that describes the relevant facts and sequence of events that gave rise to in an *Incident*.

(70) **Information** - Any type of knowledge that can be exchanged, always expressed (i.e. represented) by some type of data. Information is made into data to be stored and processed either electronically or otherwise.

(71) **Information Owner** - The responsible person acting on behalf of a *Participant* to whose system or installation the *Information* pertains.

(72) **Interconnected Power System (IPS)** - The *Transmission System*, *Distribution System* and any other connected system elements including *Customers, Power Stations and Interconnections*. 
(73) **Interconnection(s)** – An electrical connection between Rwanda and an international Participant e.g. EAPP member.

(74) **Interruptible Load** - Customer load or a combination of Customer loads that can be contractually interrupted or reduced by remote control or on instruction from the System Operator.

(75) **Interruption of Supply** - An interruption of the flow of power to a Point of Supply not requested by the Customer.

(76) **Island** – See Power Island

(77) **Labour Law** – Rwandan Law No 13/2009, the Law regulating labour in Rwanda.

(78) **Large Customer** – See definition of Large Scale Customer.

(79) **Large Scale Customer** – any person connected to MV and/or HV networks who annually consumes an electricity quantity which is equal to or higher than the minimum quantity set by the relevant authority.

(80) **Licence** – a licence issued by the Authority pursuant to the RURA Law, relating to the electricity supply industry.

(81) **Licensed activity** – An activity requiring a licence as set out in the Electricity Law.

(82) **Licensee** – any person licensed to provide electricity market administration services as defined in the Electricity Law.

(83) **Low Voltage (LV)** – AC or DC voltage less or equal to four hundred volts plus or minus five percentages.

(84) **Losses** - The technical or resistive energy losses incurred on the Transmission system and/or Distribution system.
(85) **Manual load shedding** - The load reduction obtained by manually shedding load at convenient points on the *Transmission system* or *Distribution system* under emergency conditions as required by the *System Operator*.

(86) **Medium Voltage (MV)** – AC or DC voltage above four hundred volts plus or minus ten percent and less or equal to thirty three thousand volts plus or minus ten percent.

(87) **Maximum Continuous Rating (MCR)** - The capacity that a *generating unit* is rated to produce continuously under normal conditions.

(88) **Metering** - All the *Apparatus* employed in measuring the *supply* and or use of electrical power/energy (active and reactive where applicable) together with the *Apparatus* directly associated with it.

(89) **Metering Installation** - An installation that comprises an electronic meter that can be locally or remotely interrogated, has an electronic communication link and is connected to the *TMA’s* or *DMA’s Metering* database.

(90) **Metering Point** – the position in the *IPS* at which a *Participant* measures the amount and direction of active and reactive use of electrical power.

(91) **Metering Service Provider** – A person, company or entity who undertakes *installation of Metering Installations*, maintenance or data reading tasks on behalf of a *Participant*.

(92) **Metering Threshold** – S ≥ 250 kVA (supplying or using)

(93) **Minister** – the Minister responsible for energy matters.

(94) **Ministry of Energy (MoE)** – The government entity responsible for policy on energy matters in Rwanda, currently known as the *Ministry of Infrastructure (MININFRA)*.

(95) **Month** - A calendar month comprising a period commencing at 00:00 hours on the first day of that month and ending at 24:00 on the last day of that month.
(96) **National Electrotechnical Council (NECO)** – The technical national council made up of various stakeholders focusing on national standards development, direction and adoption. The NECO works closely with the NSA.

(97) **National Energy Provider (NEP)** – The state owned, commercial entity responsible for providing electrical power/energy in Rwanda.

(98) **National Grid Control Centre (NGCC)** - means a place from where the System Operator Control Centre is located. From here, controlling and/or directing the safe operation of the Generation, Transmission and Distribution of electrical power to Customers is carried out.

(99) **National Standards Authority (NSA)** – The entity responsible for standards development, adoption and enforcement in Rwanda.

(100) **National System** – See Transmission System.

(101) **Net Capacity** - Is defined as the maximum capacity that can be supplied, measured at the point of outlet to the network, excluding the power taken by a station’s auxiliaries and the losses in the transformers that are considered integral parts of the station.

(102) **Off-grid** – an electricity supply system that is not electrically connected, directly or indirectly to any part of the IPS.

(103) **Operating Reserves** - are the additional outputs from Generating Units or reduction in demand (from loads) required to secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of operating reserves:

(a) **Primary Response**

(b) **Secondary response**

(c) **Tertiary Response**

(104) **Other Network Services** – Other Network Services are services that may be competitive or provided by TransCos/DisCos as a monopoly service. These
services are the mandatory services supplied/procured to ensure a standard of supply that meets QoS, reliability and safety standards.

(105) **Participant** - See *Grid Code Participant*.

(106) **Performance Agreement** – an enforceable agreement between a *licensee* and the *Authority* attached to the issued *licence* which establishes incentives and penalties related to the measurable performance of the *licensee*, and which is designed to improve the efficiency and effectiveness of the *licensee*.

(107) **Planned Interruption** - A *Planned Outage* that will interrupt *Customer* supply.

(108) **Planned Interruption** - A *Planned Outage* that will interrupt *Customer* supply.

(109) **Planned Outage** - An outage of equipment that is requested, negotiated, scheduled and confirmed by the *System Operator* a minimum of [14] days prior to the outage taking place.

(110) **Point of Common Coupling** - The electrical node, normally a *busbar*, in a *Transmission or Distribution substation* where different feeders are connected together for the first time.

(111) **Point of Connection (PoC)** - The electrical node in a *Transmission* or *Distribution Substation* where a *Participant* is physically connected to a *Transmission or Distribution* company assets.

(112) **Point of Delivery (PoD)** - See *Point of Supply*.

(113) **Point of Supply (PoS)** - A *Transmission or Distribution Substation* where energy can be delivered/supplied by/to *Generators/Embedded Generators/Customer*.

(114) **Power Balance Statement** – The forecast prepared by the *TSO* for the *Rwandan IPS* outlining the expected demand and *Generation* over the planning horizon as defined in the *EAPP Interconnection Code*.
(115) **Power Factor** – refers to the ratio of the RMS of the active power to apparent power measured over the same integrating period.

(116) **Power Island** – A balanced isolated group of *generating units* and/or *co-Generators* and/or *embedded Generators* with complementary local demand.

(117) **Power Pool** – The interconnection to *SAPP* or *EAPP* and the rules associated with each *Power Pool*.

(118) **Power Station (PS)** - One or more *Generating Units* at the same physical location.

(119) **Power System Stabiliser (PSS)** - Equipment controlling the Exciter output via the voltage regulator in such a way that power oscillations of synchronous machines are dampened. Input variables may be speed, frequency, accelerating power or active power (or a combination of these).

(120) **Premium supply/connection** – See *Firm Supply*.

(121) **Primary Response** – The automatic response from synchronised *Generating Units* to a rise or fall in frequency on the *IPS*.

(122) **Primary Substation Equipment** - Equipment installed at *substations* including inter alia transformers, busbars, circuit breakers, isolators, shunt devices, FACTS devices.

(123) **Production** – See *Generation*.

(124) **Protection** - The process of clearing a fault on the *IPS* in order to protect plant and people.

(125) **Quality of Supply** – the technical parameters that describe the electricity supplied to *Customers* according to RBS standards and any other RURA prescribed documents.
(126) **Reactive Power** - Instantaneous power derived from the product of voltage and current and the sine of the voltage-current phase angle which is measured in units of VAr$^s$ and multiples thereof.

(127) **Regulatory Authority** – the Rwanda Utilities Regulatory Agency (RURA) established under the *RURA Law*

(128) **Regulatory Board** – Refers to the organ, that is properly constituted with the *RURA Law*, and that assumes legal responsibility for corporate activities and who oversees the management of the Regulatory Agency.

(129) **Related business** – any business or company which directly or indirectly, in whole or in part, is owned by the licensee; or is owned by a company which owns or is owned by the *licensee*.


(131) **Scheduling** - A process to determine which Unit or *Apparatus* will be in operation and at what loading level.

(132) **Secondary Response** – The centralised automatic control that adjusts the *Active Power* production of *Generating Units* to restore frequency and interchanges with other *Control Areas* to target values following a frequency deviation (using the AGC).

(133) **Secondary Substation Equipment** - Equipment installed at *substations* including inter alia protection, telecommunications and metering equipment.

(134) **Security** - The probability of not having an unwanted operation.

(135) **Service Provider** - Any licensed entity that provides services to *Grid Code Participants* pursuant to the *Grid Code* including.

  (a) *Generator*;

  (b) *System Operator*;

  (c) *TransCo*
(d) DisCo
(e) TradeCo
(f) Large Customer
(g) Market Operator (if/when appointed).

(136) **Small Customer** – See definition of **Small Scale Customer**.

(137) **Small Scale Customer** – any person connected to LV and/or MV networks who annually consumes an electricity quantity which is lesser than the one set by the **Authority**.

(138) **Stakeholders** - The entities affected by or having a material interest in the **Grid Code**. This includes **Customers** and other industry **participants**, for example the RURA.

(139) **Standard Supply** – is defined such that if a circuit is out for maintenance or on an unplanned outage, that either no supply will be available or supply is still available but not in accordance with the technical provisions laid out in the **Grid Code**.

(140) **Substation** - A site at which primary and secondary equipment is installed including inter alia electrical isolating/switching devices, transformation equipment, shunt and FACTs devices are installed.

(141) **Supply** – the sale of electricity to **Customers**.

(142) **System Frequency** - The frequency of the fundamental AC voltage as measured at selected points by the **System Operator**. The scheduled (target) system frequency \( f \) is 50 Hz.

(143) **System Minutes** - The normalised performance indicator for interruptions, defined as:

\[
\text{(Energy interrupted (MWh) \times 60) / (system peak demand (MW))}.
\]

(144) **System Operator** – The **TSO** licensed to provide **system operation services**.
(145) **System Tests** - Those tests which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *Transmission System*. In addition, they include commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out which may have a significant impact upon the *IPS* and/or a *Transmission system*.

(146) **Telecontrol** – The general term used to refer to *Supervisory Control and Data Acquisition (SCADA) Apparatus* installed in a power system (including local and remote areas) and the associated functionality provided by such *Apparatus* for power system data retrieval and control.

(147) **Tertiary Reserves** – Changes in the dispatching and commitment of *Generating Units*. Tertiary reserves restore *Primary Reserves* and *Secondary Reserves*, to manage constraints and to bring frequency and interchanges with Control Areas back to their target when *Secondary Reserves* are depleted.

(148) **Trade** – Refers to the actions of a *TradeCo* of buying of electricity directly from *Generators* and/or *DisCos* as well as the selling of electricity to *DisCos* and/or large/small *Customers*.

(149) **TradeCo** – Refer to *Trader*.

(150) **Trader** – a legal entity that has been licenced to Trade electricity in the Rwandan electricity industry.

(151) **TransCo** - Refers to general (non-specific) responsibility of *Transmission* (also referred to as a *Transmitter*).

(152) **Transmission** – the transportation of electrical energy and power by means of *High Voltage* lines, facilities and associated meters, including the construction, operation, management and maintenance of such lines, facilities and meters.

(153) **Transmission-Connected Customer** – A *Customer* connected directly to the *Transmission system*. 
(154) **Transmission Equipment** - Equipment that is needed for the purpose of Transmission.

(155) **Transmission licensee** – a *licensee* authorised to undertake Transmission activities in accordance with the specific rights laid out in the issued licence

(156) **Transmission Metering Administrator (TMA)** - A *Participant* that is responsible for all Transmission tariff metering installation, maintenance and operations e.g. TransCo.

(157) **Transmission System (TS)** - An electricity network consisting of assets (including: substations, transformers, cables, lines and associated equipment) which are operated wholly or mainly at a *High Voltage*.

(158) **Transmission system capability statement** – The assessment made by the TSO of the capability of the IPS to support the required energy flows across the Rwandan IPS and for cross-border *interconnections* as detailed in the *EAPP Interconnection Code*

(159) **Transmission System Operator (TSO)** – the entity responsible for overall co-ordination of the planning and operation of the Transmission System by the Authority.

(160) **Unit** – Refer to *Generating Unit*

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

(162) **Unplanned Outage** – An outage that is not requested, negotiated, scheduled and confirmed 14 days before taking place. This is not a *forced outage* or *emergency outage*

### 5.2 Acronyms

(1) Note: Standard SI symbols and abbreviations are used throughout the *Grid Code* without re-definition here.
<table>
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<tr>
<th>AC</th>
<th>Alternating Current</th>
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<td>Area Control Error</td>
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<tr>
<td>ADC</td>
<td>Analogue to Digital Conversion</td>
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<tr>
<td>AGC</td>
<td>Automatic Generation Control</td>
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<tr>
<td>AMR</td>
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<td>ARC</td>
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<td>AVR</td>
<td>Automatic Voltage Regulator</td>
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<tr>
<td>COUE</td>
<td>Cost of Unserved Energy</td>
</tr>
<tr>
<td>CT</td>
<td>Current Transformer</td>
</tr>
<tr>
<td>DC</td>
<td>Direct Current</td>
</tr>
<tr>
<td>DLC</td>
<td>Dead Line Charge</td>
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<tr>
<td>DMA</td>
<td><em>Distribution</em> Metering Administrator</td>
</tr>
<tr>
<td>DPI</td>
<td>Dip Proofing Inverter</td>
</tr>
<tr>
<td>DS</td>
<td><em>Distribution</em> System</td>
</tr>
<tr>
<td>DSM</td>
<td>Demand Side Management</td>
</tr>
<tr>
<td>DTE</td>
<td>Data Terminal Equipment</td>
</tr>
<tr>
<td>EAPP</td>
<td>Eastern African Power Pool</td>
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<tr>
<td>EAPP CC</td>
<td>Eastern African Power Pool Coordination Centre</td>
</tr>
<tr>
<td>EEAR</td>
<td>Expected Energy At Risk</td>
</tr>
<tr>
<td>EENS</td>
<td>Expected Energy Not Served</td>
</tr>
<tr>
<td>E/F</td>
<td>Earth Fault</td>
</tr>
<tr>
<td>EG</td>
<td>Embedded Generator</td>
</tr>
<tr>
<td>EMS</td>
<td>Energy Management System</td>
</tr>
<tr>
<td>ESI</td>
<td>Electricity Supply Industry</td>
</tr>
<tr>
<td>FACTS</td>
<td>Flexible AC Transmission Systems</td>
</tr>
<tr>
<td>FL</td>
<td>Fault Level</td>
</tr>
<tr>
<td>GCAC</td>
<td>Grid Code Advisory Committee</td>
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<tr>
<td>GCRP</td>
<td>Grid Code Review Panel</td>
</tr>
<tr>
<td>GCS</td>
<td>Grid Code Secretariat</td>
</tr>
<tr>
<td>GCR</td>
<td>Grid Code Requirement</td>
</tr>
<tr>
<td>GOR</td>
<td>Government of Rwanda</td>
</tr>
<tr>
<td>HP</td>
<td>High Pressure</td>
</tr>
<tr>
<td>HV</td>
<td>High Voltage</td>
</tr>
<tr>
<td>HVDC</td>
<td>High Voltage Direct Current</td>
</tr>
<tr>
<td>Hz</td>
<td>Hertz</td>
</tr>
<tr>
<td>IDMT</td>
<td>Inverse Definite Minimum Time</td>
</tr>
<tr>
<td>IEC</td>
<td>International Electro-technical Commission</td>
</tr>
</tbody>
</table>
RMS: Root Mean Squared
ROCOF: Rate of Change of Frequency
ROR: Rate of Return
RURA: Rwanda Utility Utilities Regulatory Authority
RTU: Remote Terminal Unit
SAIDI: System Average Interruption Duration Index
SAIFI: System Average Interruption Frequency Index
SAIRI: System Average Interruption Restoration Index
SAPP: Southern African Power Pool
SCADA: Supervisory Control and Data Acquisition
SINELAC: Société Internationale D'Electricité Des Pays Des Grands-Lacs
SPS: Special Protection Schemes
SRMC: Short Run Marginal Cost
SSR: Sub-Synchronous Resonance
SVC: Static VAR Compensator
TMA: Transmission Metering Administrator
TRFR: Transformer
TS: Transmission System
TSO: Transmission System Operator
UAGS: Unplanned Automatic Grid Separations
UCLF: Unit Capability Loss Factor
Um, Umax: Maximum Rated Voltage
Un: Nominal Voltage
VT: Voltage Transformer
WACC: Weighted Average Cost of Capital

6 Notices and domicile

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

Rwanda Utilities Regulatory Agency (RURA)
Director of Electricity (RURA)
P.O.Box: 7289 Kigali-Rwanda
E-Mail: xxxxxxxx@rura.co.rw
Phone: (250) 252 58 45 62
(2) Communication with the Authority in respect of the normal operations of this Grid Code shall be sent to the following chosen address:

Rwanda Utilities Regulatory Agency (RURA)
Director of Electricity (RURA)
E-Mail: xxxxxx@rura.co.rw
P.O.Box: 7289 Kigali-Rwanda
Phone: (250) 252 58 45 62
Hotline: (250) 3988
Fax: (250)252 58 45 63
AND/OR
General Manager: Transmission (NEP)
Electricity, Water and Sanitation Authority (NEP)
P. O. Box 537 Kigali – Rwanda
E-Mail: xxxxxx@NEP.co.rw
Phone: (250) 259 82 02
Fax: xxxxxxxxxx

(3) Communication with the TSO in respect of the normal operations of this Grid Code shall be sent to the following chosen address:

General Manager: Transmission (NEP)
Electricity, Water and Sanitation Authority (NEP)
P. O. Box 537 Kigali – Rwanda
E-Mail: xxxxxx@NEP.co.rw
Phone: xxxxxxxx
Fax: xxxxxxxxxx

(4) 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;
if posted by pre-paid registered post, be deemed to have been received by the addressee 14 days after the date of such posting;

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

if successfully transmitted by Electronic Mail (E-Mail), be deemed to have been received by the addressee one day after dispatch.

(5) Notwithstanding anything to the contrary contained in this Grid Code, a written notice or communication actually received by one of the parties from another, including by way of facsimile Transmission, shall be adequate written notice or communication to such party.

7 Acknowledgement

(1) This Grid Code, although uniquely Rwanda, has drawn on regionally and internationally available grid codes and other documents where applicable. In particular the grid codes of EAPP, Kenya, Namibia, South Africa, Tanzania, Uganda, United Kingdom and Zambia were consulted.
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1 **Introduction**

(1) The *Governance Code* describes the provisions necessary for the overall administration and review of the various aspects of the *Grid Code*. This *Code* shall be read in conjunction with the relevant legislation, *Licences* issued to *Participants* (Generators (*GenCos*), Transmitters (*TransCos*), Distributors (*DisCos*) and Traders (*TradeCos*)), and other operating codes/guidelines that relate to the *Electricity Supply Industry (ESI)*.

(2) The accountabilities of various entities in the governance of the *Grid Code* are set out in Table 1 below.

<table>
<thead>
<tr>
<th>Body</th>
<th>Function</th>
</tr>
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<tbody>
<tr>
<td><strong>The Authority</strong></td>
<td>• <em>Grid Code</em> Development and Approval</td>
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</table>

2 **Grid Code Overview**

(1) The *Grid Code* covers a range of technical, operational, commercial and governance issues. In order to address these comprehensively in a structured way, the *Grid Code* is broken down into a number of “sub-codes”. These are:

(a) The Preamble;
(b) The Governance Code;
(c) The System Operations Code (including elements of Scheduling and Dispatch);
(d) The Network Code;
(e) The Metering Code;
(f) The Information Exchange Code;
(g) The Network Tariff Code

(2) This document deals with the Grid Code governance arrangements. It describes the process that will be followed to update the Grid Code to improve safety, reliability and operational standards. It sets out how Grid Code Participants can influence the amendment process and defines who has the authority to recommend and ultimately approve and enforce the changes. In addition the document also explains oversight and compliance requirements that need to be observed by all Grid Code Participants.

(3) The Preamble document provides the policy and industry context for the Grid Code. It also sets out the legal and regulatory references from which the Grid Code derives its authority. Furthermore, the Preamble also contains a comprehensive list of definitions and acronyms for the various terms and abbreviations used in the suite of Grid Code documents.

3 Administrative Authority

(1) The Rwanda Utility Regulatory Authority (RURA) is the administrative authority for the Grid Code (the Authority). The Authority shall ensure that the Grid Code is compiled, approved and implemented for the benefit of the ESI in Rwanda.

4 The Grid Code Advisory Committee

(1) The Authority shall constitute the Grid Code Advisory Committee (GCAC). Subsequent to its constitution, the Authority shall ensure the proper functioning of the GCAC.

(2) The GCAC is established to:
a. Review and make recommendations to the Authority regarding proposals to amend the Grid Code,

b. Review and make recommendations to the Authority regarding proposals for Exemption to comply with the Grid Code,

c. Facilitate the provision of Expert technical advice to the Authority on matters related to the Grid Code and

d. Ensure a consultative stakeholder process is followed in the formulation and review of the Grid Code,

4.1 Constitution of the GCAC

(1) The GCAC shall be a stakeholder representative panel, representing Participants in the most equitable manner possible.

(2) Members of the GCAC shall ensure that they consult with their constituencies with respect to their respective roles on the GCAC.

(3) The Authority shall annually review the composition of and constituencies represented by the GCAC to ensure that it is at all times reflective of the evolving ESI. The Regulatory Authority may decide to amend the composition of the GCAC as part of the membership review process in consultation with the GCAC. The Regulatory Authority shall ensure that members on the GCAC are able to make meaningful contributions towards the review process.

(4) The Regulatory Authority shall endeavour to balance the representation on the GCAC taking into account:

a. Public versus private

b. Service providers versus customers

c. Policy versus regulation versus implementation

(5) Following on from this it is recommended that the GCAC shall consist of at least the following:
a. One (1) member representing the System Operator (SO),

b. One (1) member representing National energy Provider (NEP) TransCo,

c. One (1) member representing NEP GenCo

d. One (1) member representing NEP DisCo

e. One (1) member representing other DisCos

f. One (1) member representing non-NEP TradeCo licensees,

g. One (1) member representing Large Customers

h. One (1) member representing Small Customers

i. One (1) member representing the National Electro-technical Council (NECO)

j. One (1) member from the Competition Authority

k. Two (2) members representing the MININFRA

l. Two (2) members from the Authority, including one to chair.

(6) The members shall be identified as follows:

a. If an industry association represents the larger part of the constituency, the association will be requested to make the nomination(s).

b. If the constituency consists of more than one association and/or a relatively small number of entities, calls for nominations will be sent to all entities. The Authority may decide on the member if more than the required number of nominations is received. The Authority may choose the member if no nominations are received.
c. If there is no identifiable entity, a public call for nomination will be sent out by the Authority. The Authority may decide on the member if more than the required number of nominations is received.

(7) The Authority shall publish changes in membership within 14 days, on the Authority’s website or other suitable communications medium.

(8) GCAC members shall serve a three-year term, after which they shall be eligible for re-appointment. Their constituency may also replace members at any given time, provided 14 days’ written notice is given to the GCS and the Authority. The Authority may request the replacement of members by their constituency upon recommendation of the GCAC, if they have not attended three consecutive meetings.

(9) Members shall nominate an alternative representative. Such nomination shall be made in writing to the GCS.

4.2 Functioning of the GCAC

(1) The GCAC shall review all proposals for amendment of or Exemptions from the Grid Code.

(2) The GCAC shall schedule at least annual review sessions. The format of a session may be determined by the GCAC, but should include a work session if proposed changes are of a substantive nature. Agenda items shall be circulated at least 14 days in advance of the review session.

(3) The GCAC shall determine its own meeting procedures and code of conduct subject to the constitutional provisions set out in this section. These procedures and code of conduct shall be published on the Authority’s website.

(4) A member from the Authority shall chair the GCAC meetings. When the Authority member or alternate is unable to attend the GCAC meeting, he/she shall make arrangements for an alternative chairperson for the duration of the meeting.

(5) A quorum shall consist of 50% of members plus one member of the GCAC. Decisions by the GCAC shall be taken by means of a majority vote of the duly
constituted GCAC. If votes are even then the chairperson shall have the deciding vote.

(6) Alternate members shall be allowed to vote only when the main member is not available for voting.

(7) If a quorum is not present within 30 minutes of the stipulated starting time of the meeting, the meeting shall make the necessary recommendation(s). Following this, the GCS shall circulate the recommendations electronically to all GCAC members for decision within five work days and such decisions to be returned to the GCS. Such decisions shall be immediately effective if voted on by a quorum. These decisions shall be minuted as confirmed at the next GCAC meeting where a quorum is present.

(8) Decisions of the GCAC shall be recorded by the GCS together with dissenting views expressed by GCAC members.

(9) The Authority shall fund the administrative activities of the GCAC. Members shall be responsible for their own travel and subsistence expenditure.

(10) The GCAC may co-opt Experts with the purpose of allowing Expert opinion to be obtained regarding complicated submissions. Industry participation and consultation shall be encouraged in, and obtained through, the activities of these Experts. The GCAC shall provide the Experts with a full scope of work and an urgency indicator for each task referred to them.

(11) The Authority shall publish the Grid Code and amendments thereto in the Government Gazette after the approval thereof by the Minister.

(12) The Authority shall publish the latest revision of the Grid Code on its website.

4.3 The Grid Code Secretariat

(1) The System Operator (SO) representative will be appointed as the Grid Code Secretariat (GCS). This decision may be reviewed by the Authority. The GCS is accountable to the Authority and the GCAC for its activities.
(2) The GCS shall perform the following functions:

(a) Ensure procedures are developed and published for the review of proposed amendments and Exemptions by the GCAC,

(b) Provide standard submission forms to Grid Code Participants,

(c) Assist, when requested, in the preparation of submissions to the GCAC,

(d) Prepare amendment and Exemption recommendations for submission to the Regulatory Board following review by the GCAC,

(e) Manage Grid Code documentation,

(f) Disseminate relevant information,

(g) Inform Participants of the progress with applications for amendment or Exemption,

(h) Co-ordinate the activities of the GCAC,

(i) Keep and circulate minutes of meetings and documentation of proceedings of the GCAC

(j) Function as a formal communication channel for the GCAC

(3) The GCS shall make the latest version of the Grid Code available electronically and notify all Participants of approved amendments or Exemptions within one week of receipt of its approval.

(4) The GCS shall make hard copies of the latest version of the Grid Code available to requesting entities, for which a nominal fee may be charged to recover reproduction costs.

5 Registration and De-registration of Grid Code Participant

(1) The GCS shall be responsible for making entries in the register of Grid Code Participants upon receipt of notification from the Regulatory Board of licensed entities (Licensees).

(2) Grid Code Participants shall be registered in their respective licensed categories namely Generation, Transmission, Distribution and Trading.
(3) No licensed entity shall have access to the Transmission System or the Distribution System before being registered as a Grid Code Participant.

(4) A Grid Code Participant whose license has been withdrawn by the Authority ceases to be a Grid Code Participant.

(5) A Grid Code Participant who wishes to de-register shall notify the GCS at least six months before the intended date of de-registration. De-registration will be carried out in accordance with guidelines as determined by the Authority.

6 Grid Code Amendment and Exemption Procedure

6.1 Changes to the Grid Code

(1) The Authority is the approval authority for the Grid Code. Only the Authority shall therefore approve any Amendments to or Exemptions from the Grid Code upon recommendation by the GCAC.

(2) Any Grid Code Participant, Customer, member of the GCAC or the Authority may propose amendments to or Exemptions from the Grid Code.

(3) Any Grid Code Participant or Customer can apply for an Exemption. Exemption from the obligation to comply with provisions of the Grid Code may be granted by the Authority for the following reasons:

(a) It may not be economically viable or technically necessary to upgrade existing equipment to the required Grid Code standards. Where this is the case the Authority will give consideration to a time bound Exemption for all or part of the Grid Code.

(b) To alleviate off-grid supply arrangements from complying with on-grid requirements.

(c) To facilitate transition through interim arrangements, and

(d) To facilitate temporary conditions necessitating Exemption.

(4) An application containing the details of a proposed change to the Grid Code shall be submitted to the GCS in accordance with the provisions set out in this Governance Code.
The procedure for amendment to or *Exemption* from the *Grid Code* is set out in Figure 1.

**Figure 1: Grid Code amendment/Exemption procedure**

### 6.2 Submissions to the GCAC

1. The GCS shall make available a list of submission dates aligned with GCAC annual meetings for each year by November of the preceding year.

2. Urgent submissions shall be dealt with at ad-hoc meetings of the GCAC as decided by the Chairperson upon advice from the GCS.

3. The GCS shall issue guidelines for submissions to the GCAC. The guidelines shall be published together with the submission dates on the Authority’s website.

4. All applications for an amendment or *Exemption* shall be submitted, in accordance with the guidelines, to the GCS. The applicant shall state the relevant clauses of the *Grid Code* and give reasons for the application.

5. A *Grid Code Participant* or *Customer* seeking *Exemption* from any provision in the *Grid Code* shall make a written request to the GCS containing the following information:
(a) Details of the applicant applying for Exemption;
(b) The clause against which the present or predicted non-compliance is identified;
(c) The specific reason for non-compliance with the provision;
(d) Identification of the Apparatus in respect of which an Exemption is being sought;
(e) Whether the Exemption sought is permanent or for a delay in achieving compliance,
(f) If a delay in achieving compliance is being sought, the date by which the non-compliance will be remedied.

(6) The GCAC shall initiate the review process without delay and shall:

(a) Firstly, if deemed necessary, ensure that the submission is referred to an Expert for detailed assessment, clarification, reformulation and/or recommendation, and
(b) Lastly, forward the recommendation to the Authority for consideration once it has been finalised.

(7) The GCAC shall take the complexity and importance of the amendment/Exemption into account in deciding on the composition of the Expert team that will deal with the submission.

(8) The GCS shall inform the applicant of the expected time frames for dealing with the submission.

(9) The applicant shall be allowed to make representation to the Expert team sessions and/or the GCAC prior to the formulation or finalisation of the GCAC recommendation to the Authority.

6.3 Recommendation to the Authority

(1) Once the GCAC has reviewed submissions, the GCS shall prepare the formal recommendation to the Regulatory Board on all proposed amendments and Exemptions to the Grid Code. The recommendation(s) to the Regulatory Board
shall also include a clear expression of divergent views on such proposals, if any were received.

(2) Full or partial *Exemption* from complying with a certain provision of the *Grid Code* may be granted to *Grid Code Participants*.

(3) All *Exemptions* granted shall prevail over the relevant section of the *Grid Code*.

(4) Amendments and *Exemptions* shall have an implementation date stipulated by *the Authority* and shall, if applicable, include time bound provisions and conditions.

(5) *The Authority* shall give notice to the GCS of the decisions reached by the *Regulatory Board*. The GCS is responsible for communicating these decisions to *Grid Code Participants*.

(6) The GCS shall update the *Grid Code* with the approved amendments and *Exemptions*.

(7) *The Authority* shall keep a register of all *Exemptions* which have been granted, identifying the name of the *Grid Code Participant* and equipment in respect of which the *Exemption* has been granted, the relevant provision of the *Grid Code*, the period of *Exemption* and the extent of compliance with the provisions.

(8) Upon request from any *Grid Code Participant*, *the Authority* shall provide a copy of such register of *Exemptions* to such *Grid Code Participant*.

7 **Dispute mediation, resolution and appeal mechanism**

(1) In addition to the provisions of the *Electricity Law* that address dispute settlement, registered *Grid Code Participants* or *Customers* shall have access to a documented procedure for handling disputes arising under the *Grid Code*. 
7.1 Complaints about the operations of the GCS or the GCAC

(1) Any complaint regarding the operations of the GCS or the GCAC shall firstly be addressed in writing to the GCS. The GCAC shall attend to such complaints at or before the next session.

(2) If the complaint is not resolved, the matter shall be referred to the Authority as a dispute as described in Section 7.3.

7.2 Disputes Relating to decisions of the Regulatory Board

(1) Any objection to decisions by the Regulatory Board shall be made in writing to the Regulatory Board.

(2) Where the Grid Code Participant or Customer is not satisfied with decision of the Regulatory Board in respect of Grid Code compliance or Grid Code violations and sanctions, and after failure of the dispute, mediation and resolution mechanism set out in this Governance Code, the party may appeal before the competent court.

7.3 Complaints between/among Customers and Grid Code Participants

(1) The procedure for handling complaints shall include the Incident Report and non-conformance report requirements as described in Sections 7.3.1 and 7.3.2.

(2) The Authority shall develop a database of disputes resolved to assist in the resolution of future disputes. Where the outcome of a dispute resolution proceeding would require or imply an amendment to the Grid Code, the Authority shall first consult with the GCAC.

7.3.1 Incident Report

(1) An Incident Report should be seen as formal communication of a problem.

(2) An effected party may issue an Incident Report to a Grid Code Participant on becoming aware of a problem or a possible breach of the Grid Code. The Grid Code Participant shall provide a reasonable explanation and, if appropriate, indicate what action it will take to address the problem.
(3) A Grid Code Participant may issue an Incident Report to a Customer, where the Customer is suspected of not complying with the necessary Grid Code requirements. The Customer shall provide the Grid Code Participant with a reasonable explanation and, where appropriate, indicate the measures that will be taken to address the problem.

(4) Grid Code Participants shall keep a log of all Incident Reports received and a log of all Incident Reports communicated to Customers.

(5) Incident Reports are operational in nature and generally require action only by technical and Customer relations staff.

7.3.2 Non-Conformance Report

(1) A Customer may issue a Non-Conformance Report when it is suspected that:

(a) The Participant has failed to provide a reasonable explanation,

(b) The Participant has willfully misrepresented the facts concerning an incident,

(c) The Participant has failed to implement the agreed preventative actions within the agreed time frame,

(d) The number of Incident Reports is excessive in relation to historical performance

(e) The actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to.

(2) A Grid Code Participant may issue a Non-Conformance Report when it is suspected that:

(a) The Customer has failed to provide a reasonable explanation,

(b) The Customer has willfully misrepresented the facts concerning an incident,

(c) The Customer has failed to implement the agreed preventative actions within the agreed time frame,

(d) The number of Incident Reports is excessive in relation to historical performance or
(e) The actions/undertakings arising from a mediation or arbitration process have not been performed/adhered to.

3) Non-Conformance Reports are indications of problems that require managerial intervention by the Grid Code Participant or Customer.

4) In the case where the parties agree with the Non-Conformance Report, recommended action shall be agreed upon. Both Participants shall implement these recommendations within an agreed time frame.

5) Participants shall report annually to the Authority on the following aspects of the procedure:
   (a) Number of non-conformance reports for each Customer category
   (b) Number of closed out non-conformance reports for each Customer category
   (c) Number of disputes resolved

6) A dispute may be declared when the parties cannot agree on the Non-Conformance Report or the recommendations of the Non-Conformance Report or when the agreed recommendations are not implemented in the agreed time frame.

7.4 Submission of Disputes to the Authority

1) Disputes are unresolved complaints between Participants that require intervention. Any Participant or Customer may submit a dispute to the Authority provided the required process of either Section 7.1 or Section 7.3 has been followed.

2) When a dispute is raised with the Authority, parties shall provide the following information:
   (a) Full history of relevant Incident Reports
   (b) Detailed Non-Conformance Report and accompanying information that gave rise to the dispute
   (c) Written report from each Participant detailing the reason for not being able to close out the Non-Conformance Report.
(3) When a dispute that has not followed the relevant procedure reaches the Authority, the Authority shall generally refer the party to the correct process.

(4) Any dispute between Grid Code Participants that remains unresolved after following the procedures set out above may be referred to the Authority for mediation.

(5) Should the dispute mediation process succeed, the parties shall strive to honour their respective undertakings/actions agreed upon to the best of their abilities.

(6) If mediation by the Authority fails to provide the parties with an agreed solution the parties may refer the matter for arbitration for final decision, alternative the aggrieved party may appeal the Regulatory Board decision before a competent court.

(7) In the event that the parties agree to refer the matter for arbitration, there shall be one arbitrator who shall be, if the issue is:

   (a) Primarily an accounting matter, an independent chartered accountant,

   (b) Primarily a legal matter, a practising senior counsel

   (c) Primarily a technical matter, a person with suitable technical knowledge.

(8) The appointment of the arbitrator shall be agreed between the Participants, but failing agreement between them within a period of 14 days after the arbitration has been demanded, either of the Participants shall be entitled to request the Authority to make the appointment and, in making its appointment, to have regard to the nature of the dispute.

(9) The following shall be considered, amongst other things, during the arbitration process:

   (a) Existing and historical performance trends or practices,

   (b) Reference standards,

   (c) Appropriate network design or operation standards,

   (d) Precedents with similar events,

   (e) Historical agreements between the participants and
(f) Total cost impact.

(10) The ruling of the arbiter shall include a time frame for implementation as well as any sharing of costs of the arbitration and shall be final and binding on the parties.

8 Compliance

(1) All Grid Code Participants and Customers shall comply with the Grid Code as updated from time to time.

(2) Grid Code Participants shall inform the Authority of any Non-Conformance Report of a material nature that has been submitted to another Participant in accordance with Section 7.3.2.

(3) The Authority may require a Participant to provide Information that is deemed necessary for the proper administration of the Grid Code. This Information shall, upon request, be treated as confidential.

9 Grid Code Violations and Sanctions

(1) If a Grid Code Participant is in breach of any of the Grid Code requirements, the Authority shall impose administrative and financial penalties as provided in the applicable laws and regulations and in the provisions of present License.

10 Code Audits

(1) A Grid Code Participant may request from another Grid Code Participant, any material in the possession or control of that Participant relating to compliance with a section of the Grid Code. The requesting Participant may not request such Information in relation to a particular section of the Grid Code within six months of a previous request made under this clause in relation to the relevant section.

(2) A request under this clause shall include the following information:

(a) Nature of the request,
(b) Name of the representative appointed by the requesting Participant to conduct the investigation

(c) the time or times at which the Information is required.

(3) The relevant Participant may not unreasonably withhold any relevant Information requested. It shall provide a representative of the requesting Participant with such access to all relevant documentation, data and records (including computer records or systems) as is reasonably requested. This Information shall be treated as confidential if requested. Any request or investigation shall be conducted without undue disruption to the business of the Participant.

11 Contracting

(1) The Grid Code shall comprise one of the standard documents that form part of the contracting arrangements between Participants in the ESI. Other contractual documents and arrangements include inter alia:

(a) Connection Agreements

(b) Use of System Agreements

(c) Operating Agreements

(d) Power Purchase Agreements and/or Supply Agreements

(e) Ancillary Services Agreements

12 Version Control

(1) The Grid Code will evolve as the ESI in Rwanda evolves.

(2) Each of the sections and Codes that collectively form the Rwandan Grid Code shall have separate version control and approvals.

(3) The GCS shall be responsible for version control.
THE RWANDA GRID CODE

System Operations Code

3 of 7 Code Documents

Version 1.0

January 2012

Enquiries: RURA, Rwanda
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1 Introduction

(1) The System Operations Code sets out the responsibilities and roles of Participants as far as the operation of the Interconnected Power System (IPS) is concerned, and more specifically issues related to:

(a) Operational reliability, security and safety;
(b) Operations planning;
(c) Ancillary Services;
(d) Scheduling and dispatch of Generation and Ancillary Services;
(e) Independent actions required and allowed by Participants;
(f) Operation of the IPS under normal and abnormal conditions;
(g) Maintenance co-ordinations and outage planning
(h) Communication of system conditions, operational Information; and
(i) Telecontrol

2 Field operation, maintenance and maintenance co-ordination / outage planning.

3 Operation of the IPS

(1) The System Operator (SO) shall be responsible for the safe and efficient operation of the IPS.

(2) The SO must be appropriately regulated by the Authority (via the relevant regulatory rules ) to ensure transparent, safe, reliable, efficient and ongoing operation of the IPS.

(3) The SO shall operate the IPS in accordance with the provisions of this Code.
(4) All Participants shall co-operate in setting up operational procedures under the direction of the SO to ensure proper operation of the IPS.

(5) The SO shall have ultimate authority and accountability for the operation of the IPS.

(6) Power Pool and other Interconnection(s) operations shall be governed by the Power Pool and related guidelines/agreements.

3.1 **SO Obligations**

(1) The SO shall be responsible for the following:

3.1.1 **System Reliability and Safety**

(1) The IPS shall be operated to achieve the highest degree of reliability practicable and appropriate remedial action shall be taken promptly to relieve any abnormal condition that may jeopardise reliable operation. Power transfers as determined by the energy Scheduling arrangements, and other transfers as far as feasible, shall be adjusted as required to achieve or restore reliable IPS operation.

(2) Voltage control, operating on the IPS and Security monitoring shall be co-ordinated on a system-wide basis in order to ensure safe, reliable, and economic operation of the IPS.

(3) 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 and/or local loads, in order to facilitate system restoration.

(4) Black start services shall be provided as available from Units.

(5) The SO shall make all reasonable endeavours to retain international interconnections unless it becomes evident that continued parallel operation of the affected parts of the IPS would jeopardise the remaining system or damage Apparatus.

(6) Should it become unsafe to operate Units in parallel with the IPS when critical levels of frequency and voltage result on the IPS from a disturbance, the
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 operation.

(7) In the event of a system separation, the SO shall ensure that the part of the IPS with a generation deficit shall automatically remove sufficient load to permit early recovery of voltage and frequency so that system integrity may be re-established.

(8) Customer load shall be shed for a reasonable period of time rather than risking the possibility of a cascading failure or operating at abnormally low frequency or voltage for an extended period of time.

(9) An internationally interconnected SO may request that the SO takes any available action to increase or decrease the active energy transfer into or out of its system by the way of emergency assistance. Such requests shall be met by the SO providing it has the capability to do so.

3.1.2 System Security

(1) The IPS shall be operated as far as practical so that instability, uncontrolled separation or cascading outages do not occur as a result of the most severe single contingency. Multiple outages of a credible nature shall be examined and, whenever practical, the IPS shall be operated to protect it against instability, uncontrolled separation and cascading outages.

(2) The SO is responsible for efficient restoration of the Transmission System (TS) after supply interruptions.

(3) The SO shall operate and maintain primary and emergency National Grid Control Centres (NGCCs) and facilities to ensure continuous operation of the IPS.

3.1.3 Operational Measures

(1) Operating instructions, procedures, standards and guidelines shall be established to cover the operation of the IPS under all system conditions.

(2) The IPS shall, as far as reasonably possible, be operated within defined technical standards and Apparatus ratings.
(3) The SO shall manage constraints on the TS through the determination of operational limits, scheduling of sufficient generation for the demand and Ancillary Services to relieve constraints.

(4) To achieve a high degree of service reliability, the SO shall ensure adequate and reliable communications between all NGCCs, Generator(s) and Substations. Communication facilities to be provided and maintained by various Participants (Generators, Embedded Generators, TransCos, DisCos, Customers) are specified in the Information Exchange Code.

(5) The SO shall be responsible for the determination of the TS protection philosophy (as contrasted and supplementary to Apparatus Protection philosophy) by means of applicable analytical studies.

(6) The SO shall determine, and review on a regular basis, relay settings for main and back-up Protection on the IPS.

4 Operations Planning

4.1 Operations Plans

4.1.1 Introduction

(1) Generator(s) and the SO are responsible for maintaining a set of current plans which are designed to evaluate options and set procedures for reliable operation through a reasonable future time period. In addition, each Generator, working with the SO, is responsible for using available personnel and system Apparatus to implement these plans to assure that the IPS reliability is maintained.

4.1.2 Objectives

(1) The objectives of the Operations Plans are:

   (a) To inform all Generators, TransCos, DisCos or Large Customers whose systems make up or are connected to the TS, of the procedures and responsibilities which are required to execute the operations plans;
(b) To enable the SO to co-ordinate operations and outages of centrally dispatched Generating Units taking into account TransCos’ TS planned outages, so as to provide the maximum reliability of electric power delivery at the lowest cost.

4.1.3 Operations Plans Requirements

(1) The operations plans for the IPS shall cover at least the following

(a) Normal Operations - where each Generator, TransCo, DisCo or Large Customer (where applicable), working with the SO, shall plan its future operations so that normal interconnection operation proceeds in an orderly consistent manner and each DisCo or Large Customer shall provide its best estimate of demand to that the SO can develop the total demand forecast.

(b) Emergency Operations - A set of plans shall be developed, maintained and implemented, by each Generator, TransCo, DisCo or Large Customer (where applicable) and the SO, to cope with operating emergencies. These plans shall be conducted with other Generators and the SO as appropriate.

4.2 Annual Operations Plan

4.2.1 Annual Operations Plan Requirements

(1) The annual operations plan shall contain sufficient information in a suitable form to assess the following:

(a) The adequacy and capability of Generating Units to meet forecasted demand and energy requirements for the next year to 5 years ahead by the end of October in each calendar year.

(b) Verification that Generation and Transmission outages are planned to maximise resource utilisation and optimise placement of Generation outages to produce a minimum running cost.

(c) Ensure that the operational problems likely to be encountered are highlighted and alternative solutions considered and evaluated; and
(d) Verification that the actions taken and emergency procedures issued to deal with possible abnormal system conditions are adequate and satisfactory.

(2) The formal operations planning procedures to implement these major steps require:

(a) The dates by which relevant programs shall be issued;

(b) Determination of the responsibility for the SO and the Generators, TransCos, DisCo/s and Large Customer to produce and provide data;

(c) Definition of the work necessary for the SO, Generators, TransCos, DisCo/s and Large Customers to contribute towards the annual operations plan; and

(d) The lines of communication and interaction between the Participants.

4.2.2 Implementation Procedure for Annual Operations Plan

(1) These procedures shall be prepared by the SO and published in a document for reference by relevant Participants.

4.2.3 Data Requirements

(1) A list of response capability data required in connection with Operating Reserve for each Generating Unit shall be submitted to the SO before the Unit comes into commercial operation and shall be updated by the end of April each calendar year and shall be within the parameters set out in the Connection Agreement between the TransCo/SO and the Generator. The SO shall be informed promptly of any change in these parameters.

4.3 Transmission Operations Planning

4.3.1 Introduction

(1) Reliable operation of the TS facilities requires co-ordination among all Participants. A high level of reliability is achieved in the operation of an IPS when:
(a) Transmission Apparatus is operated within its normal rating, except for temporary conditions after a contingency has occurred;

(b) The capability of components of the TS for both normal and emergency conditions has been established by technical studies and operating experience;

(c) When line loading, Apparatus loading or voltage levels deviate from normal operating limits or are expected to exceed emergency limits following a contingency, and if reliability of the bulk power supply is threatened, the SO shall take immediate steps to relieve the conditions. These steps include notifying other systems (international/regional), adjusting Generation, changing Scheduling between control areas, initiating load relief measures, and taking such other action as may be required; and

(d) System operation shall be co-ordinated among systems and control areas (international/regional). This includes coordination of Apparatus outages, voltage levels, MW and MVAR flow monitoring and switching that affects two or more systems of transmission components.

4.3.2 TS Operations Planning Procedures

(1) In order to accomplish the needed level of coordination, the SO shall perform studies to determine the TS operating configurations, how the system is to be operated within emergency transfer limits, how protective relaying is to be co-ordinated and how maintenance outages are to be coordinated.

4.3.3 TS Coordinating Studies

(1) Studies shall be made on a coordinated basis:

(a) to determine the facilities on each system which may affect the operation of the coordinated area;

(b) to determine operating limitations for normal operation when all transmission components are in service; and
(c) to determine operating limitations of transmission facilities under abnormal or emergency conditions.

(2) In determining ratings of transmission facilities, consideration shall be given to:

a. Thermal and stability limits

b. Short and long time loading limits

c. Voltage limits.

(3) Periodic studies shall be made to determine the Emergency Transfer Capability of transmission lines interconnecting control areas. Studies shall be made annually or at such other time that changes are made to the IPS which may affect the Emergency Transfer Capability.

(4) Studies shall be made to develop operating voltage or reactive schedules for both normal and outage conditions.

(5) Neighbouring systems shall use uniform line identifications and ratings when referring to transmission facilities of a Transmission System network. This shall foster consistency when referring to facilities and reduce the likelihood of misunderstandings.

(6) The scheduling of outages of transmission facilities which may affect neighbouring systems shall be co-ordinated with the relevant Power Pool.

(7) Any Emergency Outage which may have a bearing on the reliability of the TS shall be communicated to all systems which may be affected.

4.3.4 Protection Coordination

(1) The satisfactory operation of the TS, especially under abnormal conditions, is greatly influenced by the relay Apparatus and relay schemes in effect. Relaying of tie points between the TS is of primary concern to the respective systems, although internal system relaying often directly affects the adjacent systems.
(2) Individual *Generators, DisCo/s and Large Customers* have an obligation to implement relay application, operation, and preventive maintenance criteria according to the *SO* requirements.

(3) The application of the relay systems of the *Generators, DisCo/s and Large Customers* shall be coordinated by the *SO* to enhance the system reliability and yet have the least adverse effect on the *TS*.

(4) Each protection device shall be recalibrated every five years. A review of the protection settings shall also be carried out whenever there is an expansion or change to the transmission or generation facilities.

### 4.3.5 Remedial Action Schemes

1. *Remedial Action Schemes (RAS)*, also known as *Special Protection Schemes (SPS)*, are designed to automatically perform system protection functions other than the isolation of an electrical fault. *RAS* are designed to trip, or remove from service, *Units or Transmission* facilities under a set of carefully defined conditions. *RAS* are normally used in order to increase *TS* Capability under specified conditions. They may also be used to permit higher loading levels on the Rwandan *IPS* in those instances where additional facilities cannot be built or have been delayed. Their application is specific to particular circumstances.

2. *RAS* installed on the *EAPP Interconnected Transmission System* shall be subject to agreement between the Rwandan *SO* and the *EAPP CC*. *RAS* shall be subject to procedures detailing the operation and the conditions for switching into service of the scheme. The effects of the automatic actions arising from the operation of the *RAS* shall be subject to the specific agreement of all *Participants* involved.

3. The *SO* shall monitor the status of all *RAS* and notify relevant *Participants* and *EAPP CC* of any change of status.

### 5 Scheduling & Dispatch of Generation & Ancillary Services

1. The *SO* shall provide the scheduling and dispatch of *Generation (Generation Scheduler)*, demand forecast and *Ancillary Services* for the *IPS*. 
(2) The scheduling of the operation of the Generating Units shall ensure reliable operating margins.

(3) The responsibility for executing the energy and Ancillary Services schedules shall lie with the SO.

(4) Rescheduling during unplanned events shall be undertaken by the SO on the basis of rules provided in this Code.

(5) International Interconnection operations shall be co-ordinated from the Rwandan side by the SO within the common Power Pool arrangements.

5.1 Weekly Operations Plan

(1) Each week by 10:00 hours on Thursday, the SO shall issue a preliminary weekly operations plan which shall run from 00:00 hours on the following Monday to 00:00 hours on the subsequent Monday. The Weekly Operations Plan shall include all Units that are on standby duty as Tertiary Response.

(2) By 09:00 hours on Friday, the SO shall prepare a Weekly Operations Plan that takes into account the Units' unavailability.

(3) By 10:00 on Friday the SO shall provide the weekly international interchange schedule to relevant neighbouring TSO's and EAPP CC.

(4) Each week the SO shall determine the allocation of reserve margin to each Generator, with due consideration to start-up prices, response characteristics of the Units on the TS (ramp rates), TS constraints, availability of Units, hydro dam levels and hydro reservoirs (dams/lakes etc) inflow rates in its Weekly Operations Plan.

(5) The Weekly Operations Plan shall state the amount of operating reserve to be utilised by the SO in the scheduling and dispatching process.

(5) The Weekly Operations Plan may include the possibility of shared Operating Reserves with neighbouring systems.
5.2 Daily Generation Scheduling

(1) Scheduling the operations of Units is a major component of operations planning. Scheduling of the Units depends upon the pattern of demand by the system, the order-of-merit operation of Units, the availability of Units, the flexibility of operation of Units, constraints on the TS, security requirements and system losses.

(2) Generation Scheduling procedures include the following:

(a) The submission of an availability declaration by each Unit to the SO.

(b) The submission of relevant Generator data by each Generator to the SO.

(c) The issue by the SO of a Generation schedule the Day before the schedule Day.

(d) Where an externally interconnected Participant outside the country is connected to the IPS for the purpose of system security enhancement and economic operation (e.g. sharing of Operating Reserves), the generation scheduling and hence, power transaction shall be governed by Power Pool Rules, Inter-Utility Joint Operation Agreements and/or any other Inter-Utility Agreements.

(e) Generation scheduling requires Generator data to enable the SO to prepare a merit order to be used in scheduling and dispatch and the preparation and issue of a Generation Schedule. Based on this data, the SO is required to ensure that there is sufficient Generation to meet system demand at all times in the most economic manner, together with an appropriate margin of reserves, while maintaining the integrity of the IPS and security and Quality of Supply (QoS).

5.2.1 Scheduling Procedure

(1) The computation of the generation schedule shall require the following information from Generators:
(a) Availability declaration.

(b) *Generation* scheduling and *Generation* dispatch parameters.

(c) Other relevant *Generation* data.

(2) By 10:00 hours each *Day*, each *Generator* shall submit to the *SO* in writing (or by such agreed electronic data transmission facilities) the above information which shall be applicable for *Generation* for the next period (following *Day*) from 00:00 hours to 24:00 hours.

(3) The *Generation* data to be submitted shall be as specified by the *Information Exchange Code*.

(4) The *Generation* schedule shall be submitted by the *SO* to the relevant *Generators* by 15:00 hours.

(5) The *SO* shall provide the next day's international interchange schedule to relevant neighbouring *TSO*'s and *EAPP CC* by 15:00.

(6) Availability declaration:

(a) The availability declaration is to be expressed as a whole number of MW per generator unit, in respect of any time period (specifying the time at which each time period begins and ends). Such availability declaration shall replace any previous availability declaration period.

(b) A revised availability declaration for a *Unit* which, since the time at which the availability declaration for that generation unit under this paragraph was prepared, has either:

i. become available at a different wattage to that which such *Unit* was proposed to be made available for *Generation* in any such availability declaration whether higher or lower (including zero); or

ii. in the case of a *Unit* declared to be not available for *Generation* in an availability declaration, has become available for *Generation*. A
revised availability declaration submitted by a Generator under this clause shall state, for any Unit whose availability for any generation is revised, the time periods (specifying the time at which each time period begins and ends) in the relevant availability declaration and, if such Unit is available at what wattage, expressed in a whole number of MW, for each such time period.

5.2.2 Generation Scheduling and Dispatch Parameters

(1) The generation scheduling and dispatch parameters shall reflect the true operating characteristics of Units. Any revision to the generation scheduling and dispatch parameters from those submitted under a previous declaration shall be submitted for application for the following period. If such parameters are not revised, the previously submitted generation scheduling and dispatch parameters shall apply for the next following availability declaration period.

(2) A generation schedule shall be compiled daily by the SO as a statement of which Units may be required for the next following schedule Day:

(a) In compiling the generation schedule, the SO shall take account of and give due weight to the following factors:

i. TS constraints from time to time, as determined by the SO and as advised by Generators;

ii. for Units, their parameters registered as generation scheduling and dispatch parameters (including indications of Unit inflexibility);

iii. the requirements, as determined by the SO and as advised by DisCo/s, for voltage control and MVAR reserves;

iv. the need to provide Operating Reserves, by using the various categories of Operating Reserves, as determined by the SO;

v. the requirements as determined by the SO for maintaining frequency control.
(b) The generation schedule shall be compiled by the SO to schedule such Generating Units taking into account the above factors and in accordance with offered availability as follows:

i. in accordance with the merit order table and taking into account the start-up price element of the generation offer price;

ii. as shall in aggregate be sufficient to match at all times (to the extent possible having regard to the offered availability) the forecast system demand together with an appropriate margin of reserve, as identified in the weekly operations plan; and

iii. as shall in aggregate be sufficient to maintain frequency control.

(c) After the completion of the scheduling process, but before the issue of the generation schedule, the SO may deem it necessary to make the adjustments to the output of the scheduling process. Such adjustments may be made necessary by the following factors:

i. changes of offered availability or generation scheduling of dispatched parameters of generating Units, notified to the SO after the commencement of the scheduling process;

ii. changes to system demand forecasts;

iii. changes to transmission constraints, emerging from the necessarily interactive process of scheduling and network security assessment, including either-

   1. changes to the numerical values prescribed to existing constraint groups; or

   2. identification of new constraint groups;

iv. changes to Unit requirements within constrained groups, following notification to the SO of the changes in capability;
v. changes of Unit requirements within constrained groups, following re-appraisal of demand forecast within that constraint group;

vi. changes to any conditions which in the opinion of the SO, would impose increased risk to the IPS and would therefore require the SO to increase operational reserve levels. Such conditions include:

1. unpredicted Transmission Apparatus outages which place more than the equivalent of one large Unit at risk to any fault;

2. unpredicted outage of Generator’s Apparatus which imposes increased risk to the station output;

3. volatile weather situation giving rise to low confidence in demand forecasts;

4. severe (unpredicted) weather conditions imposing high risk to the IPS;

5. impending strikes or political unrest posing a high risk to the IPS or parts thereof; and

6. limitations or deficiencies of the SO scheduling process computational algorithms.

(d) For the following situations, a written record of these adjustments shall be kept by the SO, for a period of at least 12 months:

i. adverse weather is anticipated;

ii. demand control has been instructed by the SO; or

iii. a total or partial collapse exists.
(3) These factors may mean that a Unit is chosen other than in accordance with the merit order. Any other deviations from the use of the merit order by dispatch shall be reported by the SO including those responsible for the deviation. These reports shall be consolidated into a Weekly Report by the SO to the Generators, DisCo/s and the Authority.

(4) Content of Generation Schedule.

(a) The Information contained in the generation schedule shall indicate for a Unit or Interconnection power transaction, the period for which it is scheduled during the following Day. It shall also include Units or Interconnection power transaction running as a result of non-System reason (such as test purposes) and system requirements (such as Reactive Power reserve) and Units and Interconnected Participants assigned to a specific reserve role.

5.2.3 Special Actions

(1) The generation schedule may be followed by a list of special actions (either pre or post-fault) that the SO may request a Generator to take in respect of Units, or an Interconnection, in order to maintain the integrity of the IPS. For consumers directly connected to the Transmission System to which Units or Consumers are also connected, these special actions shall generally involve load transfer between the Points of Supply or arrangements for Demand reduction by manual or automatic means.

(2) For Interconnections these special actions shall generally involve an increase or decrease of net power flows across an Interconnection by manual or automatic means.

(3) These special actions shall be discussed and agreed upon with the Generator, Interconnection, DisCo or Customer concerned. If not agreed, Generation may be restricted or demand may be at risk.

5.2.4 Other Relevant Generation Data

(1) Other relevant generation data includes:
(a) details of any special factors which in the opinion of the Generator may have a material effect on the likely output of such Units;

(b) details of any Unit’s commissioning or changes in the commissioning programs submitted earlier.

5.2.5 Distribution System Data

(1) By 10:00 hours each Day, DisCo/s shall submit to the SO in writing confirmation or notification of the following for the following availability declaration period:

(a) constraints on its Distribution System which the SO may need to take into account;

(b) the requirements of voltage control and MVAR reserves which the SO may need to take into account for system security reasons. The form of the submission shall be that of a Unit output (both MW and MVAR) required in relation to that Distribution system following availability declaration period.

5.2.6 Revision of Generation Schedule

(1) If a revision in the availability declaration, distribution scheduling and dispatch parameters or other relevant generation data is received by the SO prior to 15:00 hours on the Day prior to the relevant schedule Day, the SO shall, if there is sufficient time prior to the issue of the generation schedule, take into account the revised availability declaration, generation scheduling and dispatch parameters or other relevant Generator data in preparing the generation schedule.

(2) If a revision in availability declaration generation scheduling and dispatch parameters of other relevant generation data is received by the SO at or after 15:00 hours in each Day but before the end of the next following schedule Day, the SO shall, if it re-schedules the Units available to generate, take into account the revised availability declaration, generation scheduling and dispatch parameters or other relevant generation data in that re-scheduling.

5.2.7 Issues of Generation Schedule
(1) The generation schedule shall be issued to Generators and Distributors or otherwise to the Generator direct by 15:00 hours each Day. If an event on the IPS (for example loss of generation in a critical part of the IPS) occurs which requires a substantial amendment in the data being used in preparing the generation schedule, the SO reserves the right to issue a revised generation schedule to the extent necessary as a result of such events.

(2) The SO may instruct Units before the issue of the generation schedule Day to which the instruction relates, if the length of the notice to synchronise requires the instruction to be given at that time.

(3) When the length of the time required for the notice to synchronise is within 30 minutes of synchronisation, causing the Unit to be unable to meet the indicative Dispatch Instructions, the Generator shall immediately inform the SO.

(4) The generation schedule received by each Generator shall contain only information relating to its Units.

5.3 Generation Dispatch

5.3.1 Merit Order Operation

(1) To meet the continuously changing demand on the IPS in the most economical manner, Units shall, as far as practicable be put on load and loaded up in accordance with “the least variable operation and maintenance costs inclusive of cost of fuel (where applicable) and consumables” (hereinafter “operating costs”) of producing electricity from each Unit i.e. Short Run Marginal Cost (SRMC). Fixed costs are not taken into consideration. At any time, the Unit with the least operating costs is used to meet the demand with a satisfactory margin.

(2) For this purpose, Units are listed according to the lowest-to-highest operating costs for each Unit and such a list is known as an “order-of-merit Schedule”.

(3) The order-of-merit Schedule for a hydro system is primarily based upon the annual energy plan for the hydro Units. The costs for hydro Units are be based upon:

   a. Efficiency of the Unit
b. The reservoir/pond level

c. Run of river status

d. Long-Run Marginal Costs (LRMCs).

(4) The order-of-merit shall be updated by the offered Generator data for the next availability declaration period. The updating shall take into account not only changes to the cost of fully loaded Units, but also the difference in the loading cost curves for each unit and for each plant.

5.3.2 Economic Dispatch

(1) Each Day is divided into a number of operating periods, depending upon the number of peaks, troughs and constant levels in the estimated demand curve.

(2) For each operating period, unit commitment requirement on line is determined by computer simulations. This value is the sum of the estimated maximum demand for the period and the specified Primary, Secondary and Tertiary Response Units.

(3) Units which are required to run for security or inflexibility purposes are allocated first.

(4) Units which committed to bilateral agreements with TradeCos are allocated next.

(5) The remainder of the estimated demand for each operating period to be supplied through a given Day shall be dispatched according to the remaining Units available in the predefined order-of-merit.

(6) In cases where only partial loading of a Unit is required for security or inflexibility reasons, the assessment of whether or not to use the remainder of the set capacity is determined, by the cost curves and Unit technical data.

(7) When scheduling over a trough, the duration of the period may be too short to shut down a less flexible unit and bring it on load again for the next period. In this case, this Unit is considered as inflexible and allocated a minimum load equal to its minimum stable generation.
(8) Scheduling shall also take into account the rates of loading and unloading of Units (ramp rates) and other station constraints such as the time intervals between synchronising or shutting down Units to each station.

5.4 SO Roles and Responsibilities

(1) In order to operate the IPS, the SO shall prepare Units operations schedules and issue unit Dispatch Instructions.

(2) The Information which the SO shall use in issuing Dispatch Instructions are as follows:

(a) The generation schedule used in dispatching the Units shall be based on the schedule prepared and supplied under the generation scheduling procedures in this clause. This takes into account information regarding availability declaration, unit commitment, offer prices, and system security constraints, system demand forecast, generation trading contracts and other relevant operational data.

(b) Commercial Ancillary Services.

5.4.1 Re-Optimization of Generation Schedule or Subsequent Schedules

(1) The SO shall re-optimise the schedules when in its judgement a need arises. As it may be the case that no notice shall be given prior to this re-optimisation, it is important that Generators always keep the SO informed of changes of availability declarations and dispatch parameters immediately as they occur.

(2) Indicative synchronising and de-synchronising times of Units in the re-optimised schedule shall be made available to the Generators who shall immediately acknowledge the times, together with their compliance of the synchronising instructions.

5.4.2 Generation Dispatch Instructions

(1) The SO shall issue Dispatch Instructions to all Generators for the schedule Day at any time during the period beginning immediately after the issue of the Generation Schedule for that schedule Day.
(2) *Dispatch Instructions* shall recognise the offered availability declared, generation scheduling and dispatch parameters and other relevant generation data supplied to the SO. A *Dispatch Instruction* may be subsequently cancelled or varied.

(3) *Units* declared available but not included in the generation schedule may be issued *Dispatch Instructions*.

(4) In addition to instructions relating to dispatch of active power, *Dispatch Instructions* may include:

(a) details of the *Operating Reserve* to be carried on each *Unit* including specification of the time scale in which that *Operating Reserve* may be transferable into increased generation output;

(b) an instruction for *Units* to provide *Ancillary Services*;

(c) Target (at instructed MW level) voltage levels or the individual reactive power output from generating *Units*. In the event of sudden change in system voltage, generating *Units* shall not take any action to override automatic MVAr response (AVR response) unless instructed otherwise by the SO, or unless immediate action is necessary to comply with stability limits. *Generators* may take such action as is necessary to maintain the integrity of their *Unit/s*;

(d) notice and change in notice to synchronise or desynchronise *Units* in a specific time-scale;

(e) an instruction for *Units* to operate in Synchronous Condenser mode; and

(f) an instruction to carry out tests as specified in the *Network Code*.

(5) The form of instructions and terms to be used by the SO in issuing instructions together with their meanings are to be mutually agreed by all relevant *Participants*.

### 5.4.3 Communication with *Generators* and *DisCo/s*
(1) System regulation shall be performed automatically using Automatic Generation Control (AGC) facilities by the SO or Dispatch Instruction shall be given by telephone or voice links (and shall include exchange of operator names) or by automatic logging devices and shall be formally acknowledged immediately by Generators. In the event that while carrying out Dispatch Instructions, an unforeseen problem arises caused by safety reasons, the SO shall be notified without delay by telephone.

5.4.4 Action Required by Generators

(1) Each Generator shall comply with all Dispatch Instructions properly given by the SO. If an unforeseen problem arises which affects the safety of the Apparatus or personnel, the Generator shall disregard Dispatch Instructions and take necessary corrective actions after which the SO shall be notified immediately.

(2) De-synchronising may take place without the SO’s prior agreement if it is done purely on safety grounds. Synchronisation or de-synchronisation as a result of inter-trip schemes or under-frequency relay operation shall be reported to the SO immediately.

(3) Each Unit shall be operated with AVR and excitation limiters in-service unless released from this obligation by the SO.

(4) To preserve the IPS synchronously connected system integrity under emergency conditions, the SO may issue Dispatch Instructions to change generation output even when this is outside the parameters so registered or amended. This may, for example, be an instruction to trip a Unit. A refusal may only be given on safety grounds (relating to person or plant).

5.4.5 Generators Response Time

(1) The response times for Units operating under different modes, and the procedure by which the response time shall be changed, shall be agreed from time to time between the SO and Generators.

5.4.6 Generating Unit Changes
(1) **Generators** shall without delay notify the **SO** by telephone of any changes or loss (temporary or otherwise) to the operational capability of any **Unit** that is synchronised or **Units** that had been instructed to synchronise within 3 hours.

### 5.4.7 Instructions to **DisCo/s**

(1) The **SO** shall issue instructions directly to **DisCo/s** for special actions and **Demand Side Management (DSM)**. These instructions may include-

(a) a demand reduction, disconnection or restoration of load and load transfer; and

(b) a demand inter-trip.

### 6 Ancillary Services

(1) The **SO** shall be responsible for the technical specification and execution of all short term (daily) reliability services for the **IPS**. These include **IPS** restoration, the balancing of supply and demand (frequency regulation), the provision of quality voltages (reactive power requirements) and the management of the real-time technical risk (reliability, **Operating Reserves**). Suitable **Ancillary Service** levels for the following year shall be calculated annually.

(2) Reliability targets shall be selected to minimise the sum of the cost to the **IPS** of providing the reliability plus the cost to the customer of limited reliability.

(3) The **SO** shall be responsible for procuring the required **Ancillary Services** that are economically efficient and needed to provide the required reliability. As a result, there will be some form of **TradeCo** licence required for the **SO** to procure **Ancillary Services** from the relevant **Participants**. The costs associated with the procurement of **Ancillary Services** shall be determined using the guidelines presented in the **Network Tariff Code** for the **SO**.

(4) All **Generators** shall inform the **SO** of their **Ancillary Services** technical capability and shall not withhold **Ancillary Services** for non technical reasons.

(5) The acquisition of **Ancillary Services** shall take place on a non-discriminatory basis.
(6) The following services are defined as Ancillary Services:

(a) Operating Reserves

(b) Black Start

(c) Reactive power compensation and voltage control from Units.

6.1 Operating Reserves

(1) Operating Reserves are required to ensure reliability of the IPS and secure capacity that will be available for reliable and secure balancing of supply and demand. There shall be three categories of Operating Reserves:

a. Primary Response

b. Secondary Response

c. Tertiary Response.

6.1.1 Primary Response

(1) Primary Response is the automatic response by synchronised Units to a rise or fall in the frequency of the IPS requiring changes in the Generating Unit’s Active Power output, to restore the frequency to within operational limits.

(2) When interconnected to the EAPP, the response to a change in system frequency shall be fully available within ten (10) seconds of the frequency change and be sustainable for a further twenty (20) seconds.

(3) When not interconnected to the EAPP, the requirement is to keep the frequency above 49.0 Hz following all credible single contingency losses. The capacity of the largest Unit connected to the system is the largest single contingency.

(4) The Primary Response requirement for the IPS shall be determined by the SO at least once a year. The requirement shall be made available to all Participants.
(5) **Demand Side Management** also participates in **Primary Response** through the self-regulating effect of frequency-sensitive loads such as induction motors or the action of under frequency relays that disconnect some demand at given frequency thresholds (not associated with automatic **Under-Frequency Load Shedding (UFLS)** schemes).

### 6.1.2 Secondary Response

(1) **Secondary Response** is a centralised control of **Active Power** on the **IPS** that adjusts the **Active Power** production of **Units** to restore the frequency and interchanges with other **Control Areas** to their target values following a frequency deviation. This response is centralised and can be automatic (via **Automatic Generation Control (AGC)**) or **Dispatch Instruction** by telephone, voice links or by automatic logging devices and shall be formally acknowledged immediately by **Generators**. This reserve is used for second-by-second balancing of supply and demand. **Primary Response** limits and arrests frequency deviations whilst **Secondary Response** restores the frequency to its target value.

(2) **Secondary Response** is the automatic response to a frequency change which is fully available by thirty (30) seconds from the time of frequency change to take over from **Primary Response**, and which is sustainable for a period of at least thirty (30) minutes. **Secondary Response** is provided by **Units** already synchronised to the **IPS** and is normally controlled by the **SO** by **AGC** (where available) or **Dispatch Instruction** as detailed above in clause (1).

(3) **Secondary Response** replaces **Primary Response** within minutes. Once replaced, **Primary Response** is again available to cover any further incidents that cause frequency deviation from the **IPS** target frequency.

(4) Sufficient **Secondary Response** shall be maintained at all times to ensure that under normal conditions the frequency is maintained within:-

- (a) 50Hz ± 0.5 Hz when not interconnected to any Power Pool

- (b) Most stringent Power Pool requirements when interconnected to one or more Power Pools
6.1.3 Tertiary Response

(1) Tertiary Response refers to SO instructed changes in the dispatching and commitment of Units. Tertiary Response is used to restore both Primary and Secondary Response, to manage constraints on the IPS and to bring the frequency and the interchanges back to their target value when the Secondary Response has been depleted.

(2) Where Tertiary Response is held on Generating Units not synchronised to the IPS, the Units shall be capable of being synchronised within a specified time generally between fifteen (15) minutes and one (1) hour. For example, non-synchronised Tertiary Response could consist of fast start hydro, gas turbine generators and steam turbine generators on hot-standby.

(3) The Tertiary Response requirement for the System shall be determined by the SO at least once a year. The requirement shall be made available to all Participants.

(4) Demand Side Management can participate in Tertiary Response. Individual contracts may be aggregated into blocks executed as defined. The aggregated block must be contracted as one block. The reserve must also be under direct control from the SO National Grid Control Centre (NGCC). These requirements are due to the need to take quick action when abnormal conditions prevail on the system.

6.2 Black Start

(1) Units capable of Black Start shall be certified by the SO and entitled to payment for the service.

(2) To ensure optimal operation of the IPS, the SO may deploy network islanding schemes on the network, e.g. an out-of-step tripping scheme.

(3) The SO shall determine the minimum requirements for each Black Start supplier and ensure that the contracted suppliers are capable of providing the service.
(4) **Black Start Units** shall perform appropriate tests and simulations on an annual basis to ensure **Black Start** facility is available. Such tests shall be witnessed and approved by the SO (as defined in the *Network Code*).

### 6.3 Reactive Power Compensation & Voltage Control from Units

(1) Voltage control and the supply or consumption of reactive power is inter-related in the sense that the voltage is affected by changes in reactive power flow. System stability depends on the voltage profile across the system. In view of these considerations it is necessary from time to time to employ certain strategic **Units** to supply or consume reactive power whether or not they are producing **Active Power**, for the purpose of voltage control.

(2) The **Unit** shall be able to provide **Reactive Power** without having to produce or consume a large quantity of **Active Power**. The amount of **Reactive Power** shall be controlled by the SO. This may be done directly through the **Energy Management system (EMS)** or by telephone.

(3) When a **Unit** is generating or pumping, **Reactive Power** supply is mandatory in the full operating range as specified in the *Network Code*.

(4) The SO shall ensure there is sufficient **Reactive Power** and **Reactive Power** reserve (slow and fast acting) to maintain transmission voltages within prescribed limits for single contingencies.

(5) The SO shall ensure sufficient **Reactive Power** and **Reactive Power** reserve (slow and fast acting) to maintain **IPS** stability.

### 7 Operational Authority

(1) The SO shall have operational authority over the TS for other networks that lie with the respective asset owners.

(2) Normal control of the various networks shall be in accordance with the operating procedures as agreed between the **Participants**.
(3) Except where otherwise stated in this section, no Participant shall be permitted to operate the Apparatus of another Participant without the permission of the 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.

(4) Not withstanding the provisions of section 3.1, Participants shall retain the right to safeguard the health of their Apparatus.

8 Operating Procedures

(1) The SO shall develop and maintain operating procedures for the safe operating of the TS, and for assets connected to the TS. These operating procedures shall be adhered to by Participants when operating Apparatus on the TS or connected to the TS.

(2) Each Participant shall be responsible for his own safety rules and procedures. The SO shall ensure the compatibility with regard to the safety rules and procedures of all Participants. However, if a dispute affecting the interpretation and/or application of safety rules and procedures should arise, such dispute shall be resolved in accordance with the procedures specified by the SO.

(3) Power Pool operating agreements shall apply in the case of operational liaison with all international power systems connected to the TS.

9 Operational Liaison, Permission for Synchronisation

(1) The SO shall sanction the switching, including shutting down and synchronising, of Units and changing over of auxiliaries on all Units.

(2) If any Participant experiences an emergency, the other Participants shall assist to an extent as may be necessary to ensure that it does not jeopardise the operation of the IPS.

(3) A Customer shall enter into an operating agreement with the SO, if it is physically possible to transfer load or Embedded Generators from one Point of Supply to another by performing switching operations on his network. This operating
agreement shall cover at least the operational communication and notice period requirements and switching procedures for such transfers.

10 Emergency and Contingency Planning

(1) The SO shall develop and maintain contingency plans to manage system contingencies and emergencies that are relevant to the performance of the IPS. Such contingency plans shall be developed in consultation with all Participants, shall be consistent with internationally acceptable utility practices, and shall include but not be limited to -

(a) Under-Frequency Load Shedding (UFLS);

(b) Meeting disaster management requirements including the necessary minimum load requirements;

(c) Forced outages at all points of interface; and

(d) Supply restoration.

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

(3) Emergency plans shall comply with applicable Power Pool agreements and guidelines.

(4) All contingency/emergency plans shall be periodically verified by actual tests to the greatest practical extent, as agreed by the Participants, without causing undue risk or undue cost. The costs of these tests shall be borne by the respective asset owners. The SO shall ensure the coordination of the tests in consultation with all affected Participants.

(5) The SO shall specify minimum emergency requirements for Distributors, Power Station local control centres and Substations to ensure continuous operation of their control, recording, enunciator and communication facilities.
(6) Other Participants shall comply with the SO’s requirements for contingency and emergency plans.

(7) Automatic and Manual Load Shedding schemes shall be made available under the direction of the SO.

(8) The SO shall be responsible for determining all operational limits on the TS by means of the applicable analytical studies.

(9) Load flow studies shall be conducted regularly to determine the effect that various component failures would have on the reliability of the IPS. At the request of the SO, DisCo/s shall perform related load flow studies on their part of the network and make the results available to the SO.

11 System Frequency and ACE Control Under Abnormal Frequency or Interchange Imbalance Conditions

(1) 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.

11.1 Description of Normal Frequency or Balancing Conditions

(1) The Control Area is considered to be under normal frequency conditions when:

(a) The immediate demand can be met with the available scheduled resources, including any expensive contingency resources;

(b) the Area Control Error (ACE) deficit does not exceed the available reserves for longer than 15 minutes;

(c) the frequency is not less than 49.8 Hz for longer than 15 minutes;

(d) applicable Power Pool control performance criteria are not violated;

(e) The frequency is within the range 49.5 to 50.5 Hz;
(f) The interconnection is intact; and

(g) There are no security and safety issues.

(2) The Control Area is considered to be under abnormal conditions if it is not in a normal condition as defined above.

11.2 Operation During Abnormal Conditions

(1) When abnormal conditions occur, corrective action shall be taken until the abnormal condition is corrected.

(2) 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.

(3) The SO shall have a designated person to refer to in periods of abnormal operation in particular, emergencies.

(4) The order in which emergency resources are to be used may change from time to time. An updated list shall be issued by the SO.

(5) Termination of the use of emergency resources shall occur as the plant shortage situation improves and after frequency has returned to normal.

(6) Automatic under-frequency systems shall be kept armed at all times.

12 Independent Actions by Participants

(1) 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 Apparatus. Advance notice of such action shall be given where possible and no financial penalties shall apply for such action. Examples include inter alia hot connections, solid breakers, malfunctioning Protection.

(2) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with agreed procedures.
(3) Following such emergency operations as may be necessary to protect the integrity of the IPS or the safety of Apparatus 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.

13 Voltage Control

(1) The SO shall be responsible for the voltage control of the TS, at Transmission level voltages as well as at the interface between TransCo/s and its customers (DisCo/s and/or Large Customers).

(2) Electricity shall be supplied at three phase alternating current which shall have a nominal voltage between phases and range, at the Points of Supply, as agreed between the Participants from time to time.

(3) TS voltages shall be controlled during normal operation to be at least within statutory limits at the Points of Supply, except where otherwise agreed between Participants.

14 Fault Reporting and Analysis/Incident Investigation

(1) Generators shall report loss of output and tripping of Units and governing to the SO within 15 minutes of the event occurring.

(2) DisCos and Customers shall report the loss of major loads (larger than 5 MW) to the SO within 15 minutes of the event occurring. Warning of the reconnection of such loads shall similarly be given with at least 15 minutes advance notice.

(3) Incidents affecting the Power Pool shall be reported to the relevant Participants within the times specified in the relevant Power Pool rules.

(4) Incidents on the IPS involving sabotage or suspected sabotage, as well as threats of sabotage shall be reported to the SO.

(5) Any major incident that materially affected the quality of the service to another Participant shall be formally investigated. These include interruptions of supply,
disconnections, under or over voltage incidents, quality of supply contraventions, etc. The following procedure should be followed:

a. A preliminary incident report shall be available after three (3) working days.

b. A final report within three (3) months.

c. The SO shall initiate such an investigation, arrange for the writing of the report and involve all affected Participants.

d. All these Participants shall make all relevant required Information available to the SO. The confidentiality status of information is described in the Information Exchange Code.

(6) A major incident is defined as an incident where:

   (a) More than 20 System Minutes of load was interrupted;

   (b) A loss of demand/generation greater than 20 MW for more than 15 minutes from a single incident; or

   (c) Severe damage to plant/Apparatus has occurred.

(7) A major incident shall have the following additional requirements:

   (a) Any Participant shall have a right to request an independent audit of the report, at their own cost, if they are not satisfied with it.

   (b) Recommendations shall be implemented by the Participants within the time frames specified.

(8) Incidents shall also be reported to the Authority as defined in the licence conditions.

(8) The SO shall be responsible for developing and maintaining an adequate system of fault statistics.
15 **Commissioning**

(1) The SO shall verify commissioning/maintenance programmes concerning operating at major **Substations** as far as is needed to ensure adequate co-ordination and reliability of the **IPS**.

(2) All aspects of commissioning by **Customers** of new **Apparatus** associated with the **Transmission** connection, or re-commissioning of such existing **Apparatus**, shall be agreed with the **SO** in writing before such commissioning starts.

(3) Aspects of commissioning 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

   (f) Site responsibilities and authorities, etc.

(4) A minimum notice period of one **Month** shall apply from the date of receipt of the request for all commissioning or re-commissioning.

(5) When commissioning **Apparatus** at the **Connection Point**, the **TransCo** shall liaise with the affected **Customers/DisCos** on all aspects that could potentially affect the **Customers’** operation.

(6) **TransCos** and **Customers/DisCos** shall perform all commissioning tests required in order to confirm that the **TransCo** and the **Customers/DisCos’** plant and **Apparatus** meet all the requirements of the **Grid Code** that have to be met before going on-line.
(7) Where commissioning is likely to involve a requirement for dispatch and/or operating for test purposes, the Generator/Customer shall, as soon as possible, notify the SO of this requirement, including reasonable details as to the duration and type of testing required.

16 Risk of Trip

(1) Generators shall identify and report all tripping risks to the SO.

(2) Participants shall minimise the risk of tripping / loss of output on their own Power Stations and Apparatus, associated with their operations and maintenance.

(3) Special care shall be taken by all Participants when planning or executing work on Protection panels. The normal outage process described in the maintenance coordination / outage planning section shall be followed. All such work shall be treated as Risk-related Outages by the SO.

(4) When a risk of trip of Apparatus or loss of output with an impact exceeding 5 MW could occur on any part of the IPS, owing to such operation and maintenance, the affected Participants shall be consulted as to who shall accept the risk before work may commence. The SO shall always be informed of such events and shall in general coordinate these requests and accept the risks.

(5) The affected Participants shall be informed when the risk has been removed.

17 Maintenance Co-ordination/Outage Planning

(1) Optimal reliability of the IPS shall be achieved by co-ordinating scheduled outages of Generation, Transmission, Distribution, Customer, Metering, communication and control facilities affecting IPS operation.

(2) The maintenance coordination / outage planning responsibility shall be borne by the SO and shall be done in collaboration with the Generation Scheduler (at the SO).

17.1 Definition of Roles and Responsibilities

17.1.1 Generation Scheduler
(1) The person responsible for scheduling and dispatching *Generation* on the *IPS* as outlined in section 5 of *this Code*.

### 17.1.2 Outage Requester

(1) An outage requester is a person requesting an outage on plant/*Apparatus* 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. This could be a *TransCo, DisCo, Generator, Customer* employee or agent, formally nominated.

### 17.1.3 *SO* Outage Scheduler

(1) The *SO* outage scheduler is a person appointed to assess the viability of a scheduled outage and either to confirm or to turn down the request. The *SO* outage scheduler shall develop and implement a non-discriminatory mechanism for resolving any scheduling maintenance conflicts. This scheduler shall optimise plant utilisation by evaluating network load capabilities, different system configurations and risk factors. It is also the responsibility of the scheduler to co-ordinate and schedule plant/*Apparatus* that affects international *Customers*.

### 17.1.4 *SO* Shift Controller

(1) The *SO* Controller on shift at the time of the outage that is responsible for finally sanctioning (or alternatively refusing) the planned outage and ensuring that the relevant operating instructions are issued.

### 17.2 Outage Process

(1) The *SO* shall develop and maintain an electronic *TS* maintenance scheduling system for the coordination of all *TS* outages.

(2) *TransCo/s* shall inform all *Customers/DisCos* of the name and contact details of the *SO* Outage Scheduler(s) in the different geographic parts of the country (if more than one exists).

(3) The *SO* shall make available to *Customers/DisCos* an outage schedule of all Planned Outages on the *TS*. The outage schedule shall cover a period of one
year rolling and shall indicate the status of the outage, i.e. whether confirmed or not.

(4) When the need for an outage is first identified it shall be entered into a transmission maintenance scheduling system as a requested outage with Planned Outage dates, times, reason, type of maintenance and request urgency assigned to it. The Outage Requester (TransCo, DisCo, Customer or Generator) shall enter this request into the maintenance scheduling system if the Outage Requester has access to this system. If no access is available, the Outage Requester shall contact the relevant SO Outage Scheduler with the request.

(5) When the SO Outage Scheduler is satisfied with the request(s) and, in the case of a calculated risk, has ensured that negotiation has taken place with the relevant Participants, the SO Outage Scheduler shall mark it as a scheduled outage.

(6) At this point the SO Outage Scheduler shall confirm the outage if it satisfies all the necessary requirements. If acceptable the SO Outage Scheduler shall change the validated request to a confirmed booking. If it is subject to the outcome of another booking, the booking shall reflect that it is linked to another confirmed booking. If the request cannot be accommodated, it shall be marked as refused, with a reason and/or an alternative suggestion for a time being given by the SO Outage Scheduler.

(7) When it is time for the confirmed booking to be executed (the outage becoming effective), the status shall be changed to taken by the SO Shift Controller if sanctioning (i.e. not refusing) the outage. While an outage is in progress the responsible Participants may report the actual state of the progress to the SO Shift Controller, who shall enter this Information into the system. This allows for the progress of the outage to be monitored by those concerned.

(8) When the outage has been completed it shall be the responsibility of the SO Shift Controller receiving the hand back, to change the status of the outage to completed.

(9) When an outage is cancelled or refused it is the responsibility of the person cancelling or refusing the outage to furnish the reasons for cancellation or refusal.
The person receiving the cancellation or refusal shall then enter this *Information* into the system when changing the status to cancelled.

(10) This shall also apply to outages that are postponed.

### 17.3 Risk Related Outages

(1) All Risk-related Outages shall be scheduled a minimum of 14 days in advance with an executable contingency plan in place. The compilation of the contingency plan is the responsibility of *TransCo’s*.

(2) These contingency plans are, in some cases, of a permanent nature and will be in force every time the same system conditions apply. These contingency plans will therefore only have to be prepared once and will come into force again (with minimal changes if needed) when the same outage is scheduled.

(3) Contingency plans shall consist of five parts:

   (a) Security linking prior to the outage, to ensure minimal risk to *Customers*.

   (b) Returning the plant that is on outage back to service as soon as possible.

   (c) Restoring supply to customers by utilising by-pass schemes.

   (d) Load shedding if necessary (load profiles shall be made available by the *Customer*).

   (e) List of contact persons.

(4) Responsibilities during the compilation of contingency plans are as follows:

   (a) The *SO* shall be responsible for identifying Risk-related Outages.

   (b) The *SO* and *Customer* control centres shall be responsible for the Security-linking instructions in the said contingency plan.
(c) It shall be the responsibility of TransCo/s to supply the Information relating to returning the plant to service.

(d) TransCo/s shall develop by-pass schemes with assistance from the SO and the Customer control centre.

(e) The SO and Customer control centres shall be responsible for identification of the load at risk and load shedding in the said contingency plan.

(5) If the contingency plan indicates that load shedding must take place it shall include the following details:

(a) The total amount of load to be shed in relation to the load profile.

(b) The point at which Customers’ load must be shed for optimal results.

(6) The relevant Customer control centres shall confirm that it is possible to execute the contingency plan successfully.

(7) To ensure that the control centre is in possession and aware of the contingency plan, the SO Outage Scheduler shall contact the control centre a Day prior to the outage.

(8) Negotiation of all Risk-related Outages, shall take place with affected Customers a minimum of 14 days prior to the outage being executed, unless otherwise agreed. Where a request comes from a Generator with a requirement for 28 days’ notice, this time period shall be respected by the Participants. Customers shall be involved in the planning phase of projects and outages that will affect them.

(9) These conditions shall also apply to all outages affecting international Customers.

(10) TransCo/s shall give DisCo/s and Customers at least 14 days’ notice of Planned Interruptions.
17.4 Maintenance Planning Between TransCo/s and Generators

(1) Over and above the requirements mentioned above, all Generators shall provide the SO with the following documents in the pro-forma format specified in the Information Exchange Code, to enable it to execute its short-term power system reliability responsibility:

(a) A 52-weeks-ahead outage plan per Power Station, showing Planned Outage and return dates and other known generation constraints, updated weekly by 15:00 every Monday (or first working Day of the week).

(b) An annual maintenance / outage plan per Unit, looking five years ahead, showing the same information as above and issued by 31 October of each year.

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

(2) Each Generator shall invite TransCo/s to provide inputs into the compiling of the five-year-ahead annual maintenance plans mentioned above, on the basis of ensuring system reliability, and shall not unreasonably reject such inputs. Any such rejection shall be substantiated by providing TransCo/s with documentary proof of the reasons.

(3) Plant versus system risks shall be carefully weighed up by the affected Participants under all circumstances. Joint risk assessments shall be undertaken and joint contingency plans under these outage conditions shall be prepared by the affected Participants.

(4) Each Generator shall ensure the absolute minimum deviation from its annual outage plan. Each deviation shall be negotiated with the SO.

(5) The SO shall coordinate network outages affecting Unit output with related Unit outages to the maximum possible extent.
(6) The objectives to be used by the SO in this maintenance coordination are (in order of descending importance:

a. Maintaining adequate reserve levels at all times

b. Ensuring reliability where TS constraints exist

c. Maintaining acceptable and consistent real-time technical risk levels.

17.5 Refusal/Cancellation of Outages

(1) No Participant may unreasonably refuse or cancel a confirmed outage, or the risks associated with that refusal/cancellation shall be transferred to that Participant. In the case of the SO cancelling the request owing to system conditions, the outage requesting Participant shall bear the cost of such cancellation.

18 Communication of System Conditions, Operational Information and IPS Performance

(1) The SO shall determine system conditions from time to time, and communicate these, or changes from a previous determination, to all Participants.

(2) These system conditions shall typically be based on a steady state and dynamic simulation of the IPS and include measures that will enhance reliability.

(3) 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.

(4) The SO shall report on both technical and energy aspects of IPS performance monthly and annually. This shall include daily demands, energies, transmission losses, interruptions and QoS aspects as detailed in the Information Exchange Code. This Information shall be available to all Participants on request.
19 Telecontrol

(1) The nationally adopted standard used by the SO is the standard to be adopted by all Participants.

(2) Where tele-control facilities are shared between Participants, operating procedures shall be agreed.
THE RWANDA GRID CODE

Network Code

4 of 7 Code Documents

Version 1.0

January 2012

Enquiries: RURA, Rwanda
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1 Introduction

(1) The Network Code covers the Transmission and Distribution network requirements applicable to prospective connection applications, technical and protection requirements, the network planning and development process as well as network maintenance requirements.

(2) This Code details involves the following Participants:

a. Generators

b. Transmitters (TransCos)

c. Distributors (DisCos)

d. Embedded Generators (EGs)

e. Transmission System Operator (TSO)

f. System Operator (SO)

g. Customers

(3) If the relevant licence has been attained from the Authority (Generation, Transmission, Distribution) and appropriate processes followed in terms of technical connection conditions by any prospective Participant (Generator, Transmitter, Distributor, Embedded Generator (EG) or Customer), Transmission System (TS) and Distribution System (DS) open access shall not be denied by any DisCo or TransCo.

2 Off-Grid conditions

(1) For Off-Grid networks, all Grid Code requirements shall be applied with the appropriate Exemptions granted by the Authority as agreed upon between the Authority and the Participant(s).
(2) If an Off-Grid network is to be connected to the IPS, the Participant(s) shall endeavour to comply with all Grid Code requirements. Any Exemptions shall be agreed upon between the Participant(s) and the Authority.

(3) Participants will be instructed by the Authority to improve their networks to comply or approach compliance with Grid Code requirements within appropriate time limits.

3 Transmission and Distribution Network connection Process

(1) Any Participant (applicant) seeking a connection to a TS/DS or seeking modifications to an existing connection shall apply in writing to the respective TransCo/DisCo using the sample application form in Appendix C in addition to supplying the required Information as outlined in the Information Exchange Code. Each TransCo/DisCo can develop and publish its own application form for connecting Generators.

(2) The relevant TransCo/DisCo shall provide a provisional quote for a new connection (or for upgrading of an existing connection) within the timeframes agreed upon. The applicant may request this provisional quote Information from the TransCo/DisCo which should be provided without commitment and without detailed studies.

(3) Once a provisional quote has been accepted by the applicant, the applicant can request a budget quote from the TransCo/DisCo. The TransCo/DisCo can charge for providing this budget quote according to the approved tariff methodology set out in the Tariff Code or as agreed upon between the applicant and the TransCo/DisCo. The cost for providing the budget quote should be in line with the costs involved in performing the relevant technical integration studies to ensure that the new/upgraded connection will not jeopardise the IPS in any way and is in compliance with the technical limit criteria set out in section 7 of this Code.

(4) Following commercial conditions being met (payment for the budget quote), the TransCo/DisCo shall provide the applicant with a budget quote. It should be noted that the budget quote can provide a number of options for connection to the TS/DS. The provision of this budget quote indicates that
that the applicant has provisionally been given a **Point of Connection** (a **Point of Connection** has been made available to the applicant).

(5) If the applicant wishes to pursue the connection to the TS/DS, following further negotiations with the respective **TransCo/DisCo** (to ensure all **Grid Code** technical and other requirements have been met and will be met during operation), the applicant can enter into a formalised **Connection Agreement** with the respective **TransCo/DisCo**. This constitutes the applicant becoming a Participant in the **Grid Code whether as a Distributor, Large Customer, Embedded Generator or Generator.**

(6) If the applicant and the **TransCo/DisCo** cannot reach an agreement on the proposed connection, a dispute as outlined in the **Governance Code** will need to be lodged.

(7) Where there is **TS/DS development** or where the provision of access to one **Participant** will have a major cost impact on other **Participant/s**, the respective **TransCo/DisCo** shall notify the affected **Participant/s** well in advance. If a dispute arises regarding funding of the connection, the matter shall be referred to the **Authority** for a decision. The **Authority** shall decide on time frames as part of this decision-making process in consultation with the affected **Participants**.

### 4 Connection conditions

(1) This section on connection conditions specifies acceptable technical, design and operational criteria which must be complied with by any relevant **Participant** connected to or seeking connection to the **TS and DS** in relation to the part of the **TS and DS** where the connection will take place. The relevant **Participants** for this include:

a. **TransCos**

b. **DisCos**

c. **System Operator (SO)**
d. Large/Small Customers

e. Generators

f. Embedded Generators (EGs)

(2) The objective of the connection conditions is to ensure that by specifying minimum technical, design and operational criteria, the basic rules for connection to the TS and DS are similar for all Participants of an equivalent category and will enable TransCos, DisCos and the SO to comply with statutory and licence obligations. Since QoS and network integrity are shared responsibilities of each TransCo, DisCo, the SO, Generators, EGs and their Customers, these conditions furthermore ensure adherence to sound engineering practice and Codes by all the Participants.

4.1 Generator connection conditions

(1) This section defines acceptable requirements for Generator connections.

(2) Units with MCR < 250 kVA do not need to comply with the connection conditions of this Code.

(3) The following guideline procedure (shown graphically in Figure 1) can be used by a prospective Generator when wanting to become a Generator:

a. A potential Generator should apply to the Authority for an Interim/Temporary Generation Licence before entering into any Connection Agreement with any TransCo or making an application to generate into the IPS (and attaining a PPA).

b. Once the potential Generator has been granted an Interim/Temporary Generation Licence, the Generator shall apply for a connection to the appropriate TransCo before connecting to the TransCo’s network (via the procedure outlined in section 3 for a network connection). A sample application form required for a Generator is included in Appendix B. It should be noted that Information included in the sample Generator application form in Appendix B will be relevant in the process of checking
whether a prospective Generator can connect to the relevant TransCo’s TS.

c. A TransCo shall, subject to the necessary technical requirements being met (following the process in section 3), make available a Point of Connection (PoC) to the requesting Generator.

d. Once the PoC has been made available to the Generator by the TransCo, the Generator can make an application to the buyer of the electricity (SO/Buyer/Trader) unless an offtaker has already approached or been approached by the Generator. The Generator shall negotiate a conditional Power Purchase Agreement (PPA) with the relevant licensed entity (SO/Buyer/Trader). The reason for the conditional PPA is that the Generator does not yet have a Generation Licence.

e. If the Generator accepts the PoC made available, the Generator shall enter into a Connection Agreement with the relevant TransCo. It should be noted that this Connection Agreement will typically be signed on condition of the prospective Generator being granted a Generation Licence by the Authority.

f. Finally, the Generator should apply to the Authority for a Generation Licence with all the previously attained documents e.g. Temporary/Interim Generation Licence, Connection Agreement, PPA (taking into account confidentiality requirements).

g. Following the Authority granting a Generation Licence to the prospective Generator, the Generator can/shall commence construction based on the statutory requirements in the Generation Licence, Connection Agreement, PPA and any other relevant documentation.
(4) Generating Units shall comply with the connection conditions based on characteristics and rated capacity as specified in Table 8 and Table 9 in Appendix A.

(5) For new Generating Units with MCR > 3.5 MW and/or Power Stations with total MCR > 7 MW, special consideration shall be given to the impact of the risks on future operating costs e.g. Ancillary Services. The SO should quantify these expected costs. The special consideration may include obtaining the Authority’s approval for including these costs in the tariff base or obliging the Generator to purchase reserves.

### 4.1.1 Protection

(1) A Generating Unit’s Generator transformer, Unit transformer, busbar ducts and switchgear shall be equipped with well-maintained protection functions, to rapidly disconnect appropriate sections of the Power Station (PS) should a fault occur within the relevant protection zones that may affect the overall TS.

(2) The following protection requirements shall be provided in order to protect the IPS:

a. **Backup impedance:** An impedance facility with a reach greater than the impedance of the generator transformer 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.

b. **Loss of Excitation:** The *Generator* shall provide a facility to detect loss of excitation on a *Unit* and initiate a *Unit* trip. The type of facility to be implemented shall be agreed with the *SO*.

c. **Pole slipping facility:** Where agreed upon between the *Generator* and the *SO*, *Units* shall be fitted with a facility protecting against pole slipping.

d. **Reverse power:** This protection shall operate in the event of a *Unit* inadvertently importing active power from the *IPS*. The *Unit* shall be disconnected from the *IPS* under this condition. Settings for reverse power shall be as agreed upon between the *Generator* and the *TransCo* and/or *SO*.

e. **Unit transformer HV backup earth fault:** This is an *IDMT* facility that shall monitor the current in the *Generating Units'* transformer neutral connection. It can detect earth faults in the transformer *HV* side or in the adjacent network. The back-up earth fault facility shall trip the *HV* circuit breaker.

f. **HV breaker fail:** The “breaker fail” protection shall monitor the *HV* circuit breakers’ operation for protection trip signals, i.e. fault conditions. If a circuit breaker fails to open and the fault is still present after a specific time delay as agreed upon with the *SO* (maximum 150 ms), it shall trip the necessary adjacent circuit breakers.

g. **HV circuit breaker pole disagreement:** The pole disagreement protection shall operate in the cases where one or two poles of a circuit breaker fail to operate after a trip or close signal. In cases where the three poles of a circuit breaker are MCRhanically coupled, pole disagreement protection is made redundant and is not required.

h. **Unit switch onto standstill:** 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 the protection and that used for the circuit breaker closing circuit shall be the same. This protection
safeguards the *Generating Unit* against an unintended connection to the *TS* (back energisation) when at standstill, at low speed or when inadequately excited.

(3) Should system conditions dictate, the *SO* shall determine other capital protection requirements in consultation with the *Generator*. This *Apparatus* may be installed at the relevant *Generating Unit* or *PS*, and be maintained by the relevant *Generator*.

(4) Any dispute as to the allocation of costs for the *Apparatus* identified in clause (2)(3) above shall be decided in terms of the dispute resolution MCRhanism in the *Governance Code*.

(5) Required *HV* breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the *SO*. Guidelines for operating times are as follows:

a. 100 ms where the *PoC* is 70 kV or above.

b. 120 ms where the *PoC* is below 70 kV.

(6) Further downstream breaker tripping and fault clearing times (away from the *PoC*), including breaker operating time, shall not exceed 120 ms plus an additional 30 ms for DC offset decay.

(7) Where so designed, earth fault clearing times for high-resistance earthed systems may exceed the tripping times of clause (5) and (6) above.

(8) The *SO* shall co-ordinate and approve all protection interfaces between *Generators* and *TransCos*.

(9) The settings of all protection tripping functions on the *Unit* protection system of a *Generating Unit*, relevant to *TS* performance and as agreed with each *Generator* in writing, shall be agreed between the *SO* (in collaboration with the *TransCo*) and each *Generator*, and shall be documented and maintained by the *Generator*, with the reference copy, which reflects the actual *PS* status at all times, held by the *SO*. The *Generator* shall control all other copies.
(10) A Generating Unit may disconnect from the TS in response to conditions at the PoC that will result in Unit damage. Protection setting documents shall illustrate PS capabilities and protection operations where relevant.

(11) Participants shall ensure that competent persons shall carry out testing, commissioning and configuration of protection systems.

(12) Prototype and routine testing shall be carried out as defined in Appendix D section D-4.1.

(13) Generators shall communicate any work on the protection circuits interfacing with Transmission protection systems (e.g. bus zone) to the SO and relevant TransCo before commencing the work. This includes work done during a Unit outage.

4.1.2 Excitation system requirements

(1) A continuously-variable, continuously-acting automatic excitation control system i.e. an Automatic Voltage Regulator (AVR) shall be installed to provide terminal voltage control of the Unit, without instability, over the entire operating range of the Unit (Note: this does not include the possible influence of a Power System Stabiliser (PSS)). Excitation systems shall comply with the appropriate requirements specified in IEC 60034.

(2) The excitation control system shall be equipped with an under-excitation limiter, load angle limiter and flux limiter as described in IEC 60034-16-1.

(3) The excitation system shall have a minimum excitation ceiling limit of 1.6 p.u. rotor current, where 1 p.u. is the rotor current required to operate the Unit at rated load and power factor (PF).

(4) The settings of the excitation system shall be agreed between the SO (in collaboration with the relevant TransCo) 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 in Appendix D section D-4.2.
(5) In addition, the Unit shall be capable of operating in the full range indicated in the generating Units’ capability diagram supplied as part of the Information Exchange Code requirements. Test procedures are given in Appendix D section 0.

(6) The active power output under steady state conditions at the PoC of any Unit shall not be affected by voltage changes in the normal operating range of ±5% of nominal voltage at the PoC.

(7) The reactive power output of a Unit under steady state conditions must be fully available within the voltage range of ±10% of nominal voltage at the PoC.

(8) PSSs as described in IEC60034-16-1 should be applied if/when required for all new Units and for existing Unit retrofitting as may be required depending on IPS requirements. The requirement for a PSS and/or any other excitation control facilities and/or AVR refurbishment shall be determined in collaboration with the SO and the relevant TransCo.

(9) Routine and prototype response tests shall be carried out on excitation systems as indicated in Appendix D section D-4.2 ensuring compliance with IEC 60034-16-3.

4.1.3 Reactive power capabilities

(1) All new Units shall be capable of supplying rated active power output at any point between the limits 0.85 PF lagging and 0.95 PF leading at the Unit terminals. Reactive output shall be fully variable between these limits under AVR, manual or other control.

(2) Routine and prototype response tests shall be carried out to demonstrate reactive capabilities as indicated in Appendix D section 0.

4.1.4 Multiple Unit Tripping (MUT) risks

(1) A PS and its Units shall be designed, maintained and operated to minimise the risk of more than one Unit being tripped from one common cause within a short duration of time. This “short duration of time” timeframe should be defined by the SO in collaboration with the Authority.
4.1.5 Governing

(2) All Units equal to or bigger than MCR > 1 MVA shall have an operational governor capable of responding according to the minimum requirements set out in this section.

(3) The speed governor must be capable of being set so that it operates with an overall speed droop of between 2% and 10%.

(4) Routine and prototype response tests shall be carried out on the governing systems as indicated in Appendix D.

4.1.5.1 System frequency deviations

(1) The nominal frequency of the IPS is 50 Hz and is normally controlled within the limits as defined in the System Operations Code. The system frequency could rise or fall in exceptional circumstances and Units must be capable of continuous normal operation for the operating frequency-voltage operating ranges indicated in and described in section 4.1.8.

(2) Considering future interconnections and power trading with surrounding countries (including EAPP and non-EAPP members), the IPS should align its frequency limits with that of EAPP in terms of the various defined system conditions as shown in Table 1 and described as follows:

a. Normal operation: Frequency shall be controlled between 49.5 Hz and 50.5 Hz (±1%) unless exceptional circumstances prevail.

b. System disturbance: Following a system disturbance such as the loss of the largest single Unit on the IPS, the frequency band is extended to between 49.0 Hz and 51.0 Hz (±2%).

c. System fault: If multiple Generating Units are tripped, major Transmission Apparatus fail or large loads are suddenly disconnected, the minimum and maximum frequency band is between 48.75 Hz and 51.25 Hz (±2.5%).
d. **Extreme**: If several of the contingencies mentioned previously occur simultaneously, the operating condition is labelled as extreme and the frequency can be below 47.5 Hz or above 51.5 Hz (-5%/+3%). This condition typically results in a system blackout as frequency recovery back to normal range is not possible.

<table>
<thead>
<tr>
<th>Operating Condition</th>
<th>Frequency (Hz)</th>
<th>Frequency variation (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Lower</td>
<td>Upper</td>
</tr>
<tr>
<td>Normal</td>
<td>49.50</td>
<td>50.50</td>
</tr>
<tr>
<td>System disturbance</td>
<td>49.00</td>
<td>51.00</td>
</tr>
<tr>
<td>System fault</td>
<td>48.75</td>
<td>51.25</td>
</tr>
<tr>
<td>Extreme system operation or fault</td>
<td>&lt;47.50</td>
<td>&gt;51.50</td>
</tr>
</tbody>
</table>

(3) The design of *Generating Units* must enable continuous operation, at up to 100% MCR (excluding Gas Turbines) active power output when the system frequency is within the ranges specified in Table 1.

(4) Frequency sensitive relay settings installed on *Generating Units* i.e. tripping time, pick up frequency, *rate of change of frequency* (ROCOF) shall be as agreed with the SO (in collaboration with the TransCo). Sections 4.1.5.2 to 4.1.5.6 shall be used as guidelines for these tripping times.

(5) The time vs system frequency plot as shown in Figure 2 shows the minimum operating range of a non-hydro *Unit*. 
4.1.5.2 High Frequency Requirements for non-hydro Units

(1) All synchronised non-hydro Units shall respond by reducing active power to frequencies above 50 Hz incorporating the allowable dead band described in section 4.1.5.6. Speed governors shall be set to give a 4% governor droop characteristic (or as otherwise agreed by the SO). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(2) 51 Hz < f ≤ 51.5 Hz condition:

a. When the frequency goes above 51 Hz but is less than 51.5 Hz the Unit shall be designed to run for at least 10 minutes over the life of the plant and for at least 5 consecutive minutes without tripping.

b. Exceeding the above limit shall prompt the Generating Unit to take all reasonable efforts to reduce the system frequency below 51.5 Hz. Such actions can include manual tripping of the running Unit. Tripping shall be
staggered in time and be initiated once the frequency has been greater than 51.5 Hz for 5 minutes. The Generator will trip a Unit, and if the system frequency does not fall below 51.5 Hz, the other Units shall be tripped in staggered format over the next 5 minutes or until the system frequency is below 51.5 Hz. The SO shall approve this tripping philosophy and the settings.

(3) $f > 51.5$ Hz condition:

a. When the frequency goes above 51.5 Hz the requirement is that the Unit shall be designed to run for at least 1 minute over the life of the plant and for at least 30 consecutive seconds without tripping.

b. When the system frequency exceeds 51.5 Hz, the Generator can start tripping Units sequentially. Tripping shall be spread over a 30 second window. If a Generator chooses to implement automatic tripping, the tripping shall be staggered. The SO shall approve this tripping philosophy and the settings.

4.1.5.3 High Frequency Requirements for hydro Units

(1) All synchronised hydro Units shall respond by reducing active power to frequencies above 50 Hz plus allowable dead band described in section 4.1.5.6. Speed governors shall be set to give a 4% governor droop characteristic (or as otherwise agreed by the SO). The response shall be fully achieved within 10 seconds and must be sustained for the duration of the frequency excursion.

(2) Currently, the IPS is not designed for (N-1) contingencies and as a result high over-frequency withstand capabilities of Generating Units will be required. If the frequency goes above 54 Hz the requirement is that the Unit shall be designed to run for at least 120 seconds over the life of the Unit and for at least 4 consecutive seconds in this range.

(3) When the system frequency increases to 54 Hz for longer than 4 seconds, the Generator shall start staggered tripping of Units as per the procedure for non-hydro Generators. Settings shall be agreed with the SO.
4.1.5.4 Low Frequency Requirements for non-hydro Units

(1) Low frequency response is defined as an Ancillary Service known as Operating Reserves. However, all Units shall be designed to be capable of having a 4% governor droop characteristic (or as otherwise agreed by the SO) with a minimum response of 3% of MCR within 10 seconds of a frequency incident. The response must be sustained for at least 15 minutes.

(2) 49.0 Hz > f ≥ 48.5 Hz condition:

a. The Unit shall be designed to run for at least 80 minutes over the life of the plant if the frequency goes below 49.0 Hz but greater than 48.5 Hz.

b. No automatic tripping of Generators shall be allowed in this region.

(3) 48.5 Hz > f ≥ 48 Hz condition:

a. The Unit shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes below 48.5 Hz but greater than 48.0 Hz. The Unit shall be able to operate for least 1 consecutive minute while the frequency is in this range.

b. If the system frequency is less than 48.5 Hz for 1 minute the Unit can be islanded or tripped to protect the Unit.

(4) 48 Hz > f ≥ 47.5 Hz condition:

a. The Unit shall be designed to run for at least 1 minute over the life of the plant if the frequency goes below 48.0 Hz but is greater than 47.5 Hz. If the system frequency is less than 48.0 Hz but is greater than 47.5 Hz for 10 seconds the Unit can be islanded or tripped to protect the Unit.

(5) f < 47.5 Hz condition:

a. If the system frequency falls below 47.5 Hz for longer than 6 seconds the Unit can be islanded or tripped.

4.1.5.5 Low Frequency Requirements for hydro Units
(1) All reasonable efforts shall be made by the Generator to avoid tripping of hydro Generating Units for under frequency conditions provided that the system frequency is above or equal to 46 Hz.

(2) If the system frequency falls below 46 Hz for more than 1 second, the Unit can be tripped to protect itself.

4.1.5.6 Dead band

(1) The maximum allowable dead band shall be 0.20 Hz for governing. This means that no response is required from Units while 49.8 Hz ≤ f ≤ 50.2 Hz.

4.1.6 Restart after station blackout

4.1.6.1 Non-hydro PSs

(1) A PS and a Unit is to be capable of being restarted and synchronised to the IPS following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply provided that the following is maintained at the PoC for the duration of the Unit start-up process:

a. A stable supply of at least 90% of nominal voltage for the Unit with on-load tap changers (OLTCs) on the generator Generating Units’ transformers, and a stable supply of at least 95% nominal voltage for Units without OLTCs on the Generating Units’ transformers.

b. An unbalance between phase voltages of no more than 3% negative phase sequence.

c. A frequency within the continuous operating range.

(2) For the purposes of this Code, examples of unreasonable delay in the restart of a PS are:

a. Restart of the first Unit that takes longer than 2 hours after restart initiation
b. Restart of the second Unit that takes longer than 1 hour after the synchronising of the first Unit.

c. Restarting of all other Units that takes longer than 30 minutes each after the synchronising of the second Unit.

d. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant Generator.

e. The start up facilities for a new Unit not being designed to minimise start up time delays for the Unit following loss of external auxiliary AC supplies for two hours or less.

(3) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix D section 0.

4.1.6.2 Hydro PSs, Diesel and Gas engines and Gas Turbines

(1) A PS or a Unit is to be capable of being restarted and synchronised to the IPS following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply provided that the following is maintained at the PoC for the duration of the Unit start-up process:

a. A stable supply of at least 90% of nominal voltage for Unit with OLTCs on the generator transformers, and a stable supply of at least 95% nominal voltage for Unit without OLTCs on the generator transformers.

b. An unbalance between phase voltages of not more than 3% negative phase sequence.

c. A frequency within the continuous operating range.

(2) For the purposes of this Code, examples of unreasonable delay in the restart of a PS are:
a. Restart of the first Unit that takes longer than 30 minutes after restart initiation

b. Restarting of all other Unit that take longer than 30 minutes each after the synchronising of the first Unit.

c. Delays not inherent in the design of the relevant start up facilities and which could reasonably be minimised by the relevant generator.

d. The start up facilities for a new Unit not being designed to minimise start up time delays for the Unit following loss of external auxiliary AC supplies for 30 minutes or less.

(3) Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix D section 0.

4.1.7 Black start capability

(1) Black start capability is defined as an Ancillary Service of which the relevant arrangements should be made by the SO in terms of the strategic type and location of Black start capability.

(2) The relevant arrangements made by the SO to procure Black start capability should strategically take into consideration EAPP Black start requirements and procedures in the EAPP Interconnection Code.

(3) PSs that have declared that they have Black start capability shall demonstrate this facility by test as described in Appendix D section 0.

4.1.8 External supply disturbance withstand capability

(1) Any Unit and any PS Apparatus shall be designed with anticipation of the following voltage conditions at the PoC:

a. A voltage deviation in the range of 90% to 110% of nominal voltage for extended periods.

b. A voltage drop:
i. to 0% for up to 0.2 s.

ii. to 75% for 2 s.

iii. to 85% for 60 s.

iv. Provided that during the 3 minute period immediately following the end of the above voltage conditions the actual voltage remains in the range 90-110% of the nominal voltage.

c. Unbalance between phase voltages of not more than 3% negative phase sequence and or the magnitude of one phase not lower than 5% than any of the other two for 6 hours.

d. Requirements to withstand the ARC cycle for faults on Transmission lines connected to PSs are as follows:

i. Single-phase faults:

1ph fault - 1ph trip - 1 second 1ph ARC dead time - 1ph ARC - 1ph fault - 3ph trip - 3 seconds 3ph ARC dead time - 3ph ARC - 1ph fault - 3ph trip - lock out.

Note: The above only applies where synchronism is maintained.

ii. Three-phase faults:

Currently it is not possible to withstand three phase faults on the IPS as a result of the radial nature of the IPS currently not designed for (N-1) operation.

(2) The frequency-voltage tolerances to be applied to Generating Units are as specified in Figure 3 as defined in IEC 600034-3.
4.1.9 On-load tap changers (OLTCs)

(1) *Generating Unit* step-up transformers shall have on-load tap changers (OLTCs) which can be remotely controlled. The range shall be agreed upon between the *TransCo* and the *Generator*.

4.1.10 Emergency *Unit* capabilities

(1) All *Generators* shall specify their *Unit’s* capabilities for providing emergency support above *MCR* under abnormal power system conditions, as detailed in the *System Operations Code*.

4.1.11 Facility for independent generator action

(1) Frequency control under system island conditions shall revert to the *PSs* as the last resort. *Units* and associated *Apparatus* shall be equipped to handle such situations. The required control range is from 49 Hz to 51 Hz.

4.1.12 Automatic under-frequency starting
(1) It may be agreed with the SO that strategic Units are capable of automatically starting within 15 minutes which shall have automatic under-frequency starting capability. This starting shall be initiated by frequency-level facilities with settings in the range 49 Hz to 50 Hz as specified by the SO.

4.1.13 Synchronisation

(1) All Units shall have the appropriate relays installed to allow for synchronisation with the IPS only once the appropriate parameters (voltage, phase and frequency) are within the error limits agreed upon between the Generator and the SO.

4.1.14 Testing and compliance monitoring

(1) 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).

(2) Within one month after the end of June and December, a Generator shall review and confirm to the SO, compliance by the PS or each of that Generator's Units with every connection condition as specified in Appendix D.

(3) A Generator shall conduct tests or studies to demonstrate that each PS and each Generating Unit complies with each of the requirements of this Code. Tests shall be carried out on new Unit, after every outage where the integrity of any connection condition may have been compromised, to demonstrate the compliance of the Unit with the relevant connection conditions. The Generator shall continuously monitor its compliance in all material respects with all the connection conditions of the Grid Code.

(4) Each Generator shall submit to the SO a detailed test procedure, emphasising system impact, for each relevant part of this Code prior to every test.

(5) If a Generator determines, from tests or otherwise, that one of its Units or PSs are not complying in any material respect with 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 PS (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 PS (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. After taking remedial action as described above, demonstrate to the reasonable satisfaction of the SO that the relevant Unit or PS (as applicable) is then complying with this Code.

(6) The SO may issue an instruction requiring a Generator to carry out a test to demonstrate that the relevant PS complies with Grid Code requirements. A Generator may not refuse such an instruction, provided it is issued timorously and there are reasonable grounds for suspecting non-compliance.

4.1.15 Suspected non-compliance

(1) If at any time the SO believes that a Unit or PS is not complying with a connection condition, the SO shall notify the relevant Generator of such non-compliance specifying the connection condition concerned and the basis for the SO's belief.

(2) If the relevant Generator believes that the Unit or PS (as applicable) is complying with the Code, then the SO and the Generator must promptly meet to resolve their difference.

(3) If no resolution is found following meetings between the SO and Generator, the dispute resolution process defined in the Governance Code should be followed.

4.1.16 Unit modifications

4.1.16.1 Modification proposals
(1) If a Generator proposes to change or modify any of its Unit in a manner that could reasonably be expected to either adversely affect that Unit's ability to inter alia comply with this Code, or changes the performance, information supplied and/or settings, then that Generator shall submit a proposal notice to the SO which shall:

a. Contain detailed plans of the proposed change or modification.

b. State when the Generator intends to make the proposed change or modification.

c. 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.

(2) If the SO disagrees with the proposal submitted, it may notify the relevant Generator, and the SO and the relevant Generator shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement.

(3) If no resolution is found following meetings between the SO and Generator, the dispute resolution process defined in the Governance Code should be followed.

4.1.16.2 Implementing modifications

(1) 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.

(2) The Generator shall notify the SO promptly after an approved change or modification to a Unit has been implemented.

4.1.16.3 Testing of modifications

(1) The Generator shall confirm that a change or modification to any of its Unit as described above conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions, promptly after the proposal has been implemented.
(2) Within 20 business days after any such test has been conducted, the relevant Generator shall provide the SO with a report in relation to that test (including test results, where appropriate).

4.1.17 Apparatus requirements

(1) Where a Generator needs to install Apparatus that connects directly with a TransCo’s Apparatus, for example in the HV yard of the TransCo, such Apparatus shall adhere to the TransCo’s design requirements.

(2) A TransCo may require Generators to provide documentary proof that their connection apparatus complies with all relevant standards, both by design and by testing.

4.2 Embedded Generator connection conditions

(1) This section defines acceptable requirements for EG connections.

(2) A similar procedure to that followed in section 4.1 for Generator connections is shown graphically in Figure 4 as a guideline for prospective EG connections.

Figure 4 Guideline connection process for a prospective Embedded Generator

(3) The applicable lower limit for Embedded Generation requiring a licence as defined in the Electricity Law applies in this Code.
4.2.1 Responsibilities

4.2.1.1 Embedded Generators responsibilities

(1) The EG shall enter into a Connection Agreement with the relevant DisCo before connecting to the relevant DS.

(2) The EG shall ensure that the reliability and Quality of Supply (QoS) complies with the terms of the Connection Agreement.

(3) The EG shall comply with the DisCo’s protection requirements detailed in this section as well as protection of own plant against abnormalities, which could arise on the DS.

(4) The EG shall be responsible for any dedicated connection costs incurred on the DS as a result of connection to the DS in compliance with the Tariff Code.

(5) The EG shall be responsible for synchronizing the PS to the DS within pre-agreed settings with the DisCo.

(6) EGs shall specify, with all relevant details, in their application for connection if the PS to be connected shall have black-start and / or self start capabilities.

4.2.1.2 Distributors responsibilities

(1) If requested by the EG, a DisCo shall provide information relating to inter alia their DS capacity, loading, short circuit levels, X/R ratio at the PoC and any other relevant information to enable the EG to identify and evaluate opportunities for connecting to the DS. The DisCo may charge the EG a reasonable fee for such information.

(2) The DisCo shall treat all applications for connection to the DS by potential EGs in an open and transparent manner that ensures equal treatment for all applicants.
(3) *DisCos* shall be responsible for the installation of bidirectional metering Apparatus between the *DisCo* and the *EG* to the standard defined in the *Metering Code*.

(4) *DisCos* shall develop detailed protection requirement guidelines for connecting *Embedded Generation* to the *DS* which complement *Embedded Generation* protection requirements in this *Code* to ensure safe and reliable operation of the *DS*.

**4.2.2 PoC technical requirements**

(1) The *EG* shall be responsible for the design, construction, maintenance and operation of the *Apparatus* on the *PS* side of the *PoC*.

(2) In the case of a dedicated *PoC*, the *EG* shall be responsible for the provision of the site required for the installation of the *DisCo’s* Apparatus required for connecting the *PS*.

(3) The technical specifications of the Connection Agreement shall be agreed upon by the *Participants* based on *DS Impact Assessment Studies*.

(4) A circuit breaker and visible isolation shall be installed at the *PoC* to provide the means of electrically isolating the *DS* from the *Embedded Generation*.

(5) The *EG* shall be responsible for the circuit breaker to connect and disconnect the *Generating Unit* as well as the required protection functionality of the *PS*.

(6) The location of the circuit breaker and visible isolation shall be decided upon by the *Participants*.

**4.2.3 Protection**

**4.2.3.1 General protection requirements**

(1) The *EG’s* protection systems shall comply with the requirements of this section complemented by detailed *DisCo* developed guidelines.
(2) *Embedded Generation* of MCR > 500 kVA shall in addition to the requirements of this section on *EGs*, comply with section 4.1 of this *Code* regarding protection requirements.

(3) Additional features including inter-tripping and *PS* status are to be agreed upon by the *Participants*.

(4) The protection schemes used by the *EG* shall incorporate adequate facilities for testing and maintenance.

(5) The protection schemes of the *EG* shall be coordinated with the relevant *DisCo’s* protection systems.

(6) The protection schemes of the *EG* should be submitted by the *EG* for approval by the relevant *DisCo and/or SO* where applicable.

(7) Each protection operation shall be investigated for its correctness based on available *Information*. The *EG* shall provide a report to the *Distributor and/or SO* when requested to do so.

### 4.2.3.2 Specific protection requirements

(1) **Phase and earth fault:** The protection system of the *EG* shall fully coordinate with the protective relays of the *DS*. Also, the *EG* shall be responsible for the installation and maintenance of all protection relays at the *PoC*.

(2) **Over-voltage and over-frequency:** The *EG* shall install over-voltage and over-frequency protection to disconnect the *PS* under abnormal network conditions as agreed between the *DisCo and the EG*.

(3) **Faults on Distribution System:** The *EG* shall be responsible for protecting its *PS* in the event of faults and other disturbances arising on the *DS*.

(4) **Islanding:**
a. The DisCo shall specify if/when the EG may remain connected if the section of the DS to which the EG is connected is isolated (islanded) from the rest of the network.

b. The PS shall be equipped with a dead-line detection protection system to prevent a Unit from being connected to a de-energised DS. The DisCo shall take reasonable steps to prevent closing circuit breakers onto an islanded network.

c. For unintentional network islanding, the EG and the DisCo shall agree on a methodology for disconnecting and connecting the Embedded Generation.

(5) **Reverse power:** Settings for reverse power shall be as agreed upon between the EG and the DisCo and/or SO. The recommended setting for reverse power is 10-20% of MCR of the Unit with a time delay of 10-30 seconds to prevent operation during power swings or when synchronising the Unit to the network.

(6) **DC Failure protection:** DC failure within the EG’s facility is a serious safety risk and the appropriate alarms (non-urgent and urgent) should be provided to the DisCo via Telecontrol facilities. Upon the receipt of an urgent DC alarm by the DisCo from the EG, the EG should disconnect and/or be disconnected from the relevant network immediately.

(7) **Phase unbalance:** Negative phase sequence overcurrent shall be applied to the EG’s PS to protect Embedded Generating Unit from unbalanced loading conditions

### 4.2.4 Excitation system

(1) **EGs** using synchronous generators as Embedded Generating Units shall be equipped with excitation controllers capable of connecting and operating on a network within statutory voltage limits operating in voltage control mode or PF control mode as agreed upon in the Connection Agreement.

(2) **EGs** using Induction (asynchronous) generators as Embedded Generating Unit will need to ensure that the PS is capable of operating in either PF control mode or voltage control mode within the statutory voltage or PF limits.
agreed upon in the *Connection Agreement*. This can be accomplished by an integrated *PS* controller via the combined use of inter alia step-up transformer tap-changers, shunt reactive devices (reactors/capacitors) and/or fast reactive power devices (SVCs, STATCOMs) as agreed upon with the *DisCo* and/or *SO* where appropriate.

(3) *EGs* using inverter type *Apparatus* as *Embedded Generating Units* shall be capable of operating in either *PF* control mode or voltage control mode operating within the statutory voltage or *PF* limits agreed upon in the *Connection Agreement*.

### 4.2.5 Governing

(1) The governing requirements of section 4.1.5 of this *Code* shall apply to *Embedded Generating Units* if MCR is greater than the limit defined in section 4.1.5.

(2) *Embedded Generating Units* with MCR lower than the limit defined in section 4.1.5 are not required to comply with governing and frequency requirements defined in this *Code*.

### 4.2.6 Synchronisation

(1) All *Embedded Generating Units* shall have the appropriate relays installed to allow for synchronisation with the *DisCo’s* network only once the appropriate parameters (voltage, phase, frequency) are within the limits agreed upon between the *DisCo* and *EG* and possibly the *SO* in selected cases.

### 4.2.7 Telecontrol

(1) Each *EG’s PS* should have an *RTU* (or appropriate *Data Terminal Equipment (DTE)*) in accordance with the relevant *DisCo’s* standard to allow for the relevant *Information* to be exchanged.

### 4.2.8 Quality of Supply (QoS)

(1) **General QoS**: The *EG* shall comply with general *QoS* requirements as agreed upon between the *DisCo* and *EG*. Suggested *QoS* standards are the IEC 61000 suite or SABS 048. *QoS* parameters include inter alia the following:
i. Voltage regulation

ii. Frequency regulation

iii. Unbalance

iv. Harmonics and inter-harmonics

v. Flicker

vi. Voltage surges and switching disturbances

vii. Voltage dips

(2) **Frequency variations:** The *PS* shall remain synchronized to the *DS* while the network frequency remains within the agreed frequency limits defined in section 4.1 of this *Code* and shall respond to frequency variations if required to do so considering section 4.2.5 of this *Code*.

(3) **Power Factor:** The *PF* at the *PoC* shall be maintained within the limits agreed upon by the *Participants* in the *Connection Agreement*.

(4) **Fault Levels:**

a. The *EG* shall ensure that the agreed fault level contribution from the *EG’s PS* (as agreed in the *Connection Agreement*) shall not be exceeded.

b. The *DisCo* shall ensure that the agreed fault level in the network at the *PoC* shall not be exceeded.

(5) **Telemetry:** The *EG* shall have the means to remotely report any status change of any critical function that may negatively impact on the *QoS* on the *DS* (via *RTU/DTE* as defined in section 4.2.7).

### 4.3 DisCos and Customers

(1) This section describes connection conditions for *DisCos* and *Customers*.
(2) A TransCo shall, subject to the conditions in section Error! Reference source not found., and in collaboration with the TSO offer to connect and, subsequent to the signing of the relevant agreements, make available a PoC to any requesting DisCo or Customer.

(3) A DisCo and/or Customer may request additional reinforcements to the TS over and above that which could be economically justified as described in section 7 of this Code. In this case, a TransCo shall provide such reinforcements if the DisCo and/or Customer agrees to bear the costs, which shall be priced according to the Tariff Code.

(4) Single phase system and interconnection requirements in rural areas

4.3.1 Power Factor

(5) DisCos and Customers shall take all reasonable steps to ensure that PFs at each respective Point/s of Connection from the respective TransCo are, unless otherwise agreed to in contracts between Participants:

a. PF = 0.90 importing or higher during periods of peak demand and during shoulder hours.

b. PF = 1.00 importing or lower during periods of minimum demand.

(6) The above PF requirement applies to each PoC individually for DisCos and/or Customers with more than one PoC.

(7) An exporting PF shall not be acceptable, unless specifically agreed to in the relevant agreements made between Participants.

(8) Aside from the typical kVA (power factor) charge levied in tariffs as detailed in the Tariff Code, technical requirements regarding PFs should be less than the agreed upon limit between Participants during any 10 (ten) demand-integrated half hours in a single calendar Month, the Participants shall cooperate in determining the plans of action to rectify the situation. Overall lowest economic cost solutions shall be sought.
(9) The required PF from an EG shall be in accordance with the required reactive power control and/or voltage control mode as agreed upon between the EG and the DisCo.

4.3.2 Protection

(1) Each Participant shall take all reasonable steps to protect its own Apparatus.

(2) All Apparatus connected directly to a TS or DS Substation shall comply with the Grid Code protection requirements described in section 6 of this Code. The detailed protection applications, insofar as the equipment of one Participant may have an impact on the other, shall be agreed to in writing by the relevant Participants.

(3) DisCos that have Customers connected directly to Transmission Substations are responsible for ensuring that such Customers comply with the relevant protection standards.

(4) A DisCo’s protection system shall be appropriately designed and maintained to ensure optimal grading, coordination and discrimination to ensure safety and minimum interruptions to EGs and Customers.

(5) The Customer shall install and maintain protection, which is compatible with the existing DS protection. The Customer’s protection settings shall ensure coordination with the DisCo’s protection systems.

(6) The Customer shall, on request, provide the relevant DisCo with test certificates, prior to commissioning, of the protection system/s that are installed at the PoS (PoS) with the DisCo.

(7) The DisCo shall, on request, provide the relevant TransCo and the SO (where appropriate) with test certificates, prior to commissioning, of the protection system/s that are installed at the PoS with the relevant TransCo.

(8) Where Apparatus or protection schemes are shared, the Participants shall provide the necessary Apparatus and interactions between the Apparatus of the other party.
4.3.3 Fault levels

(1) Minimum fault levels at each PoS on the TS shall be maintained by TransCos under normal operating conditions to ensure compliance with the adopted QoS standards and to ensure correct operation of protection systems.

(2) TransCos shall annually provide the SO with minimum and maximum normal operating fault levels for each PoS on their respective TS.

(3) The SO shall annually, or when substantial deviations have taken place, publish updated minimum and maximum normal operating fault levels for each PoS on the TS.

(4) Participants shall ensure their Apparatus is capable of operating in these specified fault level ranges.

(5) If Participants Apparatus fault level ratings are or will be exceeded, they shall promptly notify the relevant TransCo. The TransCo shall seek overall lowest economic cost solutions to address fault level problems.

(6) Corrective action shall be for the cost of the relevant asset owner and per the implementation plan agreed to.

(7) Any dispute as to the allocation of costs for the equipment identified in clause (6) above shall be decided in terms of the dispute resolution MCRhanism in the Governance Code.

(8) TransCos and DisCos shall liaise with the relevant Participants as per the process defined in section 7 of this Code, on how fault levels are planned to change and on the best overall solutions when equipment ratings become inadequate. Overall lowest economic cost solutions shall be sought and a joint impact assessment shall be done covering all aspects. Transco and DisCos shall communicate the potential impact on safety of people when Apparatus ratings are exceeded.

4.3.4 Earthing requirements
(1) A *TransCo* or *DisCo* shall advise *Customers* about the neutral earthing methods used in their *TS* or *DS* respectively.

(2) The method of neutral earthing used on those portions of *Customer’s* installations that are physically connected to the *TS* or *DS* shall comply with the nationally adopted earthing standards for *Customers* and for *EGs*.

(3) Protective earthing of *Apparatus* must be done in accordance with the applicable national standard, e.g. IEC 61936 or IEEE 142 or SABS 076.

(4) Designed lightning protection requirements shall be applied to the *TS* or *DS* and relevant switching yards.

(5) *Substation* earthing requirements shall be in accordance with IEC 61936 or IEEE 142 or SABS 076.

### 4.3.5 Network performance indices

(1) Network performance predominantly relates to *QoS* standards adopted by the *Authority*. These are a shared responsibility between *DisCos* and *Customers* (*Large Customers*, *Small Customers* and *EGs*). Suggested *QoS* standards are the IEC 61000 suite or SABS 048

(2) *The Authority* shall be responsible for determining and setting of *DS* performance indices as well as the format in which these are reported. These performance indices predominantly relate to the nationally adopted *QoS* standards and as a guideline the following indices are included in this *Code*:

a. Interruption performance

b. Voltage regulation performance

c. Dip performance

d. Total harmonic distortion performance (harmonics and inter-harmonics)

e. Flicker performance
f. Unbalance performance

g. Voltage dip performance

h. Frequency

i. Voltage surges and switching disturbances

(1) Before the end of each year each DisCo and Customer (where applicable) shall publish and submit to the Authority its targets for performance for the following year.

(2) The Authority shall annually evaluate the DS performance indices to compare each DisCo’s actual performance with the DisCo’s unique targets set by the Authority. The Authority shall publish these comparative results.

(3) If a DisCo’s or Customer’s network performance falls below acceptable levels and affects the QoS to other Participants or causes damage (direct or indirect) to a Participants Apparatus, the Participant responsible for the deviation shall endeavour to find a solution to remedy the cause of damage as well as possible payment for the damaged Apparatus.

(4) Acceptable network performance shall be as follows:

a. Performance comparable to benchmarks for similar networks.

b. Performance that complies with a TransCo’s operating and maintenance procedures at the relevant Substation.

c. Performance that complies with the minimum agreed standards of QoS.

(5) If DisCos or 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, for example by improving line maintenance practices, improving protection and breaker operating times, if necessary by replacing problematic Apparatus, installing additional network Apparatus, changing operating procedures (by installing fault-limiting devices
if the number of faults cannot be reduced). These changes should be effected in consultation with the relevant Participant on both the technical scope and time frame.

(6) Where QoS standards are transgressed, the relevant Participants shall co-operate and agree in determining the root causes and plans of action. If no solution is found or responsibility for damaged Apparatus taken, the process for dispute resolution process, as described in the Governance Code, shall be followed.

4.3.6 A TransCo’s delivered QoS

(1) QoS is a shared responsibility between a TransCo and its Customers (Distributors, Large Customers and Generators), and shall be based on nationally adopted QoS standards as agreed with all relevant Participants i.e. IEC 61000 suite or SABS 048.

(2) A TransCo shall agree in writing with its Customers, for every PoS, at least on the following QoS parameters, taking local circumstances, historical performance and the relevant standards into account:

a. Interruption performance

b. Voltage regulation

c. Frequency regulation

d. Voltage unbalance on the TS should at least comply with the limits set in the EAPP Interconnection Code or better based on the nationally adopted standards.

e. Harmonics and inter-harmonics (EAPP limits use IEEE 519)

f. Voltage flicker on the TS should at least comply with the limits set in the EAPP Interconnection Code or better based on the nationally adopted standards.

g. Voltage surges and switching disturbances
h. Performance on the TS should be evaluated based on nationally adopted standards as no voltage dip performance criteria are set in the EAPP Interconnection Code.

(3) A Participants responsibilities in terms QoS to the TransCo’s TS and IPS in general should also be included in the relevant agreements between Participants.

(4) A reasonable time period for monitoring performance shall be allowed before performance is agreed to for the first time in terms of interruptions and dips. This time period shall be two years unless otherwise agreed. For harmonic voltages and voltage unbalance, performance can be monitored after one week of measurements is completed.

(5) Where a TransCo fails to meet the agreed QoS parameters, it shall take reasonable steps at own cost to overcome the shortcomings. These changes should be effected in consultation with the relevant Participant on both the technical scope and the time frame.

4.3.7 A DisCo’s QoS

(1) A DisCo shall agree in writing with its Customers, for every PoS, at least on the following QoS parameters based on the nationally adopted QoS standard e.g. relevant parts of the IEC 61000 suite or SABS 048, taking local circumstances, historical performance and the relevant standards into account:

a. Interruption performance

b. Voltage regulation

c. Frequency regulation

d. Unbalance

e. Harmonics and inter-harmonics

f. Flicker
g. Voltage surges and switching disturbances

h. Voltage dips

(2) A Participants’ (EGs, Large Customers, and Small Customers) responsibilities in terms QoS to a DisCo’s DS should also be included in the agreement.

(3) Where a DisCo fails to meet the agreed QoS parameters, it shall take reasonable steps at own cost to overcome the shortcomings. These changes should be effected in consultation with the relevant Participant on both the technical scope and the time frame.

4.3.8 Losses in the Distribution system

(1) Losses shall be classified into three categories:

a. Technical Losses.


c. Administrative Losses.

5 Technical design requirements

(1) The connection requirements set out in this Code are based on minimum technical requirements laid out in the EAPP Interconnection Code to ensure the IPS is compliant with regional requirements. This will ensure the possibility of future electrical power trading with EAPP members as a result of EAPP interconnection requirements being met.

5.1 Transmission system design requirements

(1) The purpose of this section is to document the design and other technical standards that TransCos shall adhere to.

5.1.1 Apparatus design standards

(1) Primary Substation Equipment shall comply with the relevant IEC standards

Application of the relevant standards shall cater for local conditions, e.g.
increased pollution levels and should be determined by or in consultation with the relevant Participant.

(2) A TransCo shall design, install and maintain equipment in accordance with the appropriate standards.

(3) Participants may require the TransCo to provide documentary proof that their connection Apparatus complies with all relevant standards, both by design and by testing.

5.1.2 Clearances

(1) Clearances for all electrical equipment shall at least comply with IEC 61936 and the applicable Labour Law in terms of occupational health and safety.

5.1.3 CT and VT ratios, accuracies and cores

(1) All TransCos shall adopt the same standards for Current Transformer (CT) and Voltage Transformer (VT) ratios, cores, transducers and Analogue to Digital Conversion (ADC) (in the form of Remote Terminal Unit (RTUs) or appropriate DTE) as defined in IEC 60044.

5.1.4 Standard busbar arrangements

(1) Substations on the TS shall be configured in accordance with the principles described in this section.

(2) The reliability and availability of the TS is not dependent only on TS lines, transformers, and other Primary Substation Equipment and Secondary Substation Equipment; the busbar layout also plays a part. It is important that the busbar layout and what it can do for the reliability and availability of the TS to Participants be prudently assessed when planning the TS.

(3) The standard Substation arrangement shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar. A TransCo shall, however, consider local conditions, type of Apparatus used, type of load supplied and other factors in the assessment of the required busbar redundancy.
(4) Bypasses provide high line availability by allowing circuit breakers to be taken out of service for maintenance and testing without affecting line availability. Therefore, the following bypass arrangements are Grid Code requirements:

a. A bypass with single busbar selection shall be used at HV on single line radial feeds to provide continuity of supply when maintaining and/or testing the line breakers.

b. A bypass with double busbar selection shall be used on HV lines where justified.

c. HV busbar configuration at PSs shall be agreed upon with Generators and TransCos.

5.1.5 Motorised isolators

(1) All TS Apparatus isolators on the TS shall be motorised at new Substations.

5.1.6 Earthing and surge protection

(2) Each TransCo shall ensure adequacy of all earthing installations to provide for:

a. The safety of personnel and the public.

b. The correct operation of all protection systems.

c. Agreed design and performance levels.

(3) Earthing isolators shall be provided at new Substations where the fault level is designed for 20 kA and above.

(4) Each TransCo shall provide adequate protection to limit lightning surges and/or switching surges at the PoC to the standardised limits e.g. IEC 60071, using the best technology methods e.g. IEC 62305. Protection systems shall be adequate to protect Apparatus to the rating levels as outlined in Table 2 (220 kV and 400 kV included for future network expansion) to align with the EAPP Interconnection Code which are based on IEC 60071.
Table 2 Permissible transient voltages on Rwandan TS (based on IEC 60071)

<table>
<thead>
<tr>
<th>Nominal Voltage (kV)</th>
<th>Highest operating voltage on equipment (kV)</th>
<th>Withstand voltage for lightning surge (kV), LIWL</th>
<th>Withstand voltage for switching surge (kV), SIWL</th>
<th>50 Hz, 1 min. withstand voltage (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>70</td>
<td>72.5</td>
<td>325</td>
<td>N/A</td>
<td>140</td>
</tr>
<tr>
<td>110</td>
<td>123</td>
<td>550</td>
<td>N/A</td>
<td>230</td>
</tr>
<tr>
<td>220</td>
<td>245</td>
<td>950</td>
<td>N/A</td>
<td>395</td>
</tr>
<tr>
<td>400</td>
<td>420</td>
<td>1050-1425</td>
<td>850/950/1050</td>
<td>N/A</td>
</tr>
</tbody>
</table>

5.1.7 Telecontrol

(1) All Participants shall be permitted to have Telecontrol/SCADA facilities in the Substations, yards and/or buildings of other Participants, to perform agreed monitoring and control. The asset owner shall provide access to such Apparatus.

(2) TransCos shall have reliable Telecontrol/SCADA facilities (including telecommunications, computers and RTUs/DTE) for the TS, to provide the necessary response where system conditions require by the SO. e.g. IEC 60870.

5.1.8 Transformer tap changers

(1) TransCos shall install remote tap changing facilities on all new transformers in their respective TS networks.

(2) Transformers used in the TS are normally not on automatic tap change. Transformers supplying Customers and/or DisCos are usually on automatic tap change. As a result, the voltage levels, sensitivity and time delay settings as well as on/off auto tap changing shall be determined by the SO in consultation with the Customer and/or DisCo and the TransCo.

5.1.9 Substation drawings
(1) The following set of engineering drawings shall be made available by the respective asset owners for all Points of Connection and Points of Supply, if required by other relevant Participants for the purposes of connection to the network:

a. Station Electric Diagram

b. Key Plan

c. Bay Layout Schedules

d. Foundation, Earth Mat and Trench Layout

e. Steelwork Marking Plan

f. Security Fence Layout

g. Terrace, Road and Drainage Layout

h. Transformer Plinth

i. General Arrangement

j. Sections

k. Slack Span Schedule

l. Barrier Fence Layout

m. Security Lighting

n. Floodlighting Parameter Sketch

o. Protection details

p. Contour Plan
q. Any other engineering drawings required as agreed upon between Participants.

(2) All engineering drawings shall use the standard electrical symbol set used in IEC 60617.

5.1.10 Voltage

(1) Steady state voltage conditions at TS busses should be maintained within the following ranges unless otherwise agreed upon between Participants:

a. Under normal conditions: \( 0.95 \text{ p.u.} \leq V_{bus} < 1.05 \text{ p.u.} \)

b. Under any single contingency: \( 0.90 \text{ p.u.} \leq V_{bus} < 1.10 \text{ p.u.} \)

c. Multiple contingency: \( 0.85 \text{ p.u.} \leq V_{bus} < 1.20 \text{ p.u.} \)

5.2 Distribution System design requirements

(1) The purpose of this section is to document the design and other technical standards that DisCos shall adhere to.

5.2.1 Apparatus design standards

(1) All DisCos shall use the standards for Apparatus on the DS as defined in section 5.1.1

5.2.2 Clearances

(1) All clearances shall be as defined in section 5.1.2

5.2.3 CT and VT ratios, accuracies and cores

(1) All DisCos shall adopt the same standards outlined in section 5.1.3.

5.2.4 Standard busbar arrangements

(1) Substations on the DS shall be configured in accordance with the principles described in this section.
(2) For reliability and availability of the DS, it is important that the busbar layout and what it can do for the reliability and availability of the DS be assessed by the relevant DisCo when planning the DS.

(3) The standard Substation arrangement shall be based on providing one busbar zone for every main transformer/line normally supplying that busbar. A DisCo shall, however, consider local conditions, type of Apparatus used, type of load supplied and other factors in the assessment of the required busbar redundancy. A DisCo shall also adhere to the system reliability criteria as described in section 7 of this Code.

(4) The bypass facilities to be provided at DisCo Substations shall be as follows:

a. A bypass with single busbar selection shall be used at MV voltage levels on single line radial feeds to provide continuity of supply when maintaining and/or testing the line breakers.

b. A bypass with double busbar selection shall be used at MV voltage levels where justified.

c. Busbar configuration at PSs (EGs) shall be agreed upon with EGs and/or co-generators.

5.2.5 Motorised isolators

(1) The provision of motorised isolators at new Distribution Substations is to be based on individual merit (importance ranking vs. cost vs. remoteness).

5.2.6 Earthing and surge protection

(1) Each DisCo shall ensure adequacy of all earthing installations to provide for:

a. The safety of personnel and the public.

b. The correct operation of all protection systems.

c. Agreed design and performance levels.
(2) Earthing isolators shall be provided at new *Substations* where the fault level is designed for 20 kA and above.

(3) Each *DisCo* shall provide adequate protection to limit lightning surges and/or switching surges at the *PoC* to the standardised limits (e.g. IEC 60071) using the best technology methods e.g. IEC 62305. The protection shall be adequate to protect the *Apparatus* to the rating levels as outlined in Table 2 (existing *DS* voltage levels included) which are based on IEC 60071.

**Table 3 Permissible transient voltages on Rwandan *DS* (based on IEC 60071)**

<table>
<thead>
<tr>
<th>Nominal Voltage (kV)</th>
<th>Highest operating voltage on equipment (kV)</th>
<th>Withstand voltage for lightning surge (kV), LIWL</th>
<th>Withstand voltage for switching surge (kV), SIWL</th>
<th>50 Hz, 1 min. withstand voltage (kV)</th>
</tr>
</thead>
<tbody>
<tr>
<td>6.6</td>
<td>7.2</td>
<td>40-60</td>
<td>N/A</td>
<td>20</td>
</tr>
<tr>
<td>11</td>
<td>12</td>
<td>60/75/95</td>
<td>N/A</td>
<td>28</td>
</tr>
<tr>
<td>15</td>
<td>17.5</td>
<td>75/95</td>
<td>N/A</td>
<td>38</td>
</tr>
<tr>
<td>30</td>
<td>36</td>
<td>145/170</td>
<td>N/A</td>
<td>70</td>
</tr>
</tbody>
</table>

5.2.7 Telecontrol

(1) All *Participants* shall be permitted to have *Telecontrol/SCADA* facilities in the *Substations*, yards and/or buildings of the other *Participants*, to perform agreed monitoring and control. The asset owner shall provide access to such *Apparatus*.

(2) *DisCos* shall have reliable *Telecontrol/SCADA* facilities (including telecommunications, computers and *RTUs/DTE*) for the *DS* connected directly to the *TS*, to provide the necessary response where system conditions require by the *SO*. e.g. IEC 60870.

5.2.8 Transformer tap changers

(1) *DisCos* shall install automatic tap changing facilities on all new transformers in their respective networks.
(2) Transformers used in the DS should be on automatic tap change to ensure sufficient voltage regulation. The voltage levels, sensitivity and time delay settings as well as on/off auto tap changing shall be determined by the DisCo in consultation with the Customer where appropriate.

5.2.9 Substation drawings

(1) Engineering drawing requirements are as given in section 5.1.9.

5.2.10 Voltage

(2) Steady state voltage conditions at DS busses shall be maintained within the following ranges unless otherwise agreed upon between the DisCo and Customer:

a. Under normal conditions: \[0.95 \text{ p.u.} \leq V_{bus} < 1.05 \text{ p.u.}\]

b. Under any single contingency: \[0.90 \text{ p.u.} \leq V_{bus} < 1.10 \text{ p.u.}\]

c. Multiple contingency: \[0.85 \text{ p.u.} \leq V_{bus} < 1.20 \text{ p.u.}\]

5.2.11 Apparatus requirements

(1) Apparatus at the PoC with a Customer, EG and/or TransCo shall comply with the DisCo’s standards as approved by the Authority and/or agreed upon in the Distribution Licensee’s licence and/or any equivalent national standards.

(2) The DisCo shall provide a Customer and/or EG with the necessary information to enable the Customer and/or EG to install Apparatus with the required rating and capacity.

(3) DisCos, their Customers and/or EGs shall ensure that all Apparatus at the PoC is maintained at least in accordance with the manufacturers’ specifications.

(4) DisCos, their Customers and/or EGs connected to at MV and HV levels shall retain test results and maintenance records relating to the Apparatus at the PoC and make this information available if requested by the DisCo and/or Authority.
6 Protection requirements

(1) This section specifies the minimum protection requirements for DisCos and TransCos as well as typical settings, to ensure adequate performance of the TS and DS.

(2) TransCos and DisCos shall at all times install and maintain protection installations that comply with the provisions of this section and other relevant sections of this Code.

(3) TransCos and DisCos shall conduct periodic testing of Apparatus and systems to ensure and demonstrate that these are performing to the design specifications. Test procedures shall be according to the manufacturers’ specifications.

(4) TransCos and DisCos shall make available to Customers, Generators and EGs all results of tests performed on Apparatus for reasonable requests.

(5) Protection schemes for TSs and DSs are generally divided into:

a. Apparatus protection.

b. System protection.

6.1 Apparatus protection requirements

6.1.1 Feeders above 70 kV

6.1.1.1 Design standard

(1) New feeders shall be protected by two equivalent protection systems – Main 1 and Main 2.

(2) The Main 1 and Main 2 protection systems shall be fully segregated in secondary circuits in line with EAPP Interconnection Code requirements.

(3) Separately fused and monitored DC supplies should be used for Main 1 and Main 2 protections systems.
(4) The Main 1 and Main 2 protection systems should not be identical to avoid the risk of simultaneous protection system failure.

(5) An additional backup earth fault function shall be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in detection of high resistance faults.

6.1.1.2 Protection settings

(1) The protection relays shall provide reliable protection against all possible short circuits, provide remote and/or local back up for not cleared busbar faults and are not set to provide overload tripping.

(2) Where required, the feeder protection may be set, if possible, to provide remote back up for other faults as agreed upon with other Participants.

6.1.1.3 Automatic Re-closing

(1) Automatic re-closing (ARC) facilities shall be provided on all feeders. Single pole and three-pole tripping as well as high speed ARC facilities should be available.

(2) The SO shall decide on ARC selection based on real time system, environmental constraints and consultation with Customers, with regard to Apparatus capabilities and in accordance with the ARC philosophy below. All ARC settings and methodology shall be implemented by TransCos and be made available to Customers on request.

(3) ARC Cycles:

a. Either of the following two ARC cycles for single phase faults shall be used:

i. Double attempt ARC cycle for persistent fault:
   1ph fault – 1ph trip – 1ph ARC – 3ph trip – 3ph ARC – 3ph trip – lockout

ii. Single attempt ARC cycle for persistent fault:
   1ph fault – 1ph trip – 1ph ARC – 3ph trip – lockout
(4) On some lines the ARC should be switched off according to the following operational needs:

a. Sporadically, when high risk of line fault is recognised, for live line work or to reduce breaker duty cycle where breaker’s condition is questionable.

b. Periodically, during season of high fault frequency,

c. Permanently, on lines with the highest fault frequency throughout the year or on Customers' request.

d. Whenever an ARC could initiate a severe power swing or an Out-Of-Step condition in weakly interconnected sub-systems (system instability).

e. Predominantly radial networks

6.1.1.4 Single Phase ARC

(1) In most applications the dead time of single phase ARC is selected to one (1) second but may differ for different system requirements. The SO shall define the required single phase ARC switching times with the relevant TransCos. The closing of the circuit breaker is performed without synchronisation as the synchronism is maintained via remaining phases that are closed during the incident.

6.1.1.5 Three Phase ARC

(1) Fast ARC: Fast ARC i.e. fast closing of the breaker without checking synchronism, should not be used on the TS to avoid stress to the rotating machines at the PSs and at the Customers’ plant. This option is available on protection panels and can be selected in case of emergency i.e. when as a result of outages or disturbance load/generation islands are interconnected via a single line. The operating practice, however, is to use only single phase ARC (fast by its nature) in such situations as a compromise between supply reliability and stress to the equipment.

(2) Slow ARC:
a. The Dead Line Charging (DLC) end is selected in line with Table 4 based on Fault Level (FL) at the connected Substations A and B.

<table>
<thead>
<tr>
<th>End B</th>
<th>End A</th>
<th>Substation FL&lt;10 kA</th>
<th>Substation FL&gt;10 kA</th>
<th>PS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FL&lt;10 kA</td>
<td>Substation with higher FL</td>
<td>Substation A</td>
<td>Substation B</td>
<td></td>
</tr>
<tr>
<td>Substation</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>FL&gt;10 kA</td>
<td>Substation B</td>
<td>Substation with lower FL</td>
<td>Substation B</td>
<td></td>
</tr>
<tr>
<td>PS</td>
<td>Substation A</td>
<td>Substation A</td>
<td>PS with lower FL</td>
<td></td>
</tr>
</tbody>
</table>

b. In most applications the dead time of slow ARC is selected to three (3) seconds at DLC end of the line. At the synchronising end of the line the ARC dead time is usually selected to four (4) seconds. The close command will be issued only after synch-check is completed. This may take up to two (2) seconds if synchronising relays are not equipped with direct slip frequency measurement. The circuit breaker may take longer to close if its MCRHanism is not ready to close after initial operation at the time when the close command is issued.

c. On the line between two PSs the dead time at the DLC end should be extended to 25 seconds to allow generators’ rotors oscillations to stabilise. The dead time on the synchronising end is then extended accordingly to 30 seconds.

d. The synchronising relays are installed at both ends of the line to enable flexibility in ARC cycles and during restoration.

6.1.1.6 Power swing blocking

(1) New distance relays on the TS shall be equipped with a power swing blocking facility. All unwanted operations of distance relays during power swing conditions shall be blocked on the TS.

6.1.2 Feeders at 70 kV and below (at TransCo Substations)

6.1.2.1 Design Standard
(1) These feeders shall be protected by a single protection system, incorporating either distance or differential protection relays, unless otherwise agreed. Back up shall be provided by definite time and inverse definite minimum time (IDMT) over-current and earth fault relays.

(2) The protection shall be equipped with ARC. 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

(1) Protection relays shall provide reliable protection against all possible short circuits, provide remote and/or local back up for un-cleared busbar faults and should not be set to provide overload tripping where measurements and alarms are provided on SCADA systems. In isolated applications where SCADA systems are not available, overload tripping will be provided. Where overload conditions are alarmed at the National Grid Control Center (NGCC), it is the NGCC’s responsibility to reduce load to an acceptable level as quickly as possible.

6.1.2.3 Automatic re-closing

(1) The DisCos in collaboration with Customers shall determine ARC requirements. The SO may specify additional ARC requirements for system security reasons, which could extend beyond TransCo Substations.

6.1.2.4 Tele-protection requirements

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

6.1.2.5 Transformer and reactor protection

(1) The standard schemes for transformer protection comprise a number of systems, each designed to provide the requisite degree of protection for the following fault conditions:

a. Faults within the tank
b. Faults on transformer connections e.g. bushings

c. Overheating

d. Faults external to the transformer

(2) A TransCo and/or DisCo shall consider the application of the following relays in the design of the transformer/reactor protection system:

a. Transformer IDMT E/F: The MV E/F Protection is to discriminate with the feeder back-up E/F Protection for feeder faults

b. Transformer HV/MV IDMT O/C: The SO requires that the IDMT O/C does not operate for twice transformer full load. Overloading of the transformer is catered for by the winding and oil temperature protection. However, network requirements may be such that the above standard cannot be applied. In this case, a mutually agreed philosophy between the SO and the relevant TransCo may be used.

c. Transformer HV/MV Instantaneous O/C: This back-up protection is to cater for flash-overs external to the transformer (TRFR) on the HV side or MV side and should operate for minimum fault conditions (possibly as well for an E/F condition). However, the overriding requirement is not to operate for through faults or for magnetising inrush current.

d. Transformer LV (Tertiary) IDMT/Instantaneous O/C: This protection is to operate for external faults between the main delta winding of the TRFR and the auxiliary TRFR, but not for faults on the secondary side of the auxiliary TRFR. The auxiliary TRFR is protected by Buchholz and temperature protection.

e. Transformer Current Differential Protection: This is the main transformer protection for E/F and phase-to-phase faults. Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current, with its attendant decaying offset.
f. **Transformer High Impedance Restricted E/F:** This protection is an additional protection for the TRFR differential relay to cater for earth faults close to the star point of the TRFR winding, where phase-to-phase faults are unlikely to occur.

g. **Transformer Thermal Overload:** Winding temperature and oil temperature relays, supplied by the manufacturer are used to prevent TRFR damage or life time reduction due to excessive loading for the ambient temperature or during failure of the cooling system.

### 6.1.2.6 TS busbar and bus-coupler protection

(1) Busbars shall be protected by current differential protection (bus-zone) 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.

(2) Bus-coupler and bus-section panels are to be equipped with O/C and E/F protection.

### 6.1.2.7 TS shunt capacitor protection

(3) All the new HV 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.

(4) 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 in section 6.1.2.9.

6.1.2.8 Over-voltage protection

(1) Primary protection against high transient over-voltages of magnitudes above 140% of nominal (e.g. induced by lightning) shall be provided by means of surge arrestors.

(2) 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.

(3) Over-voltage protection on shunt capacitors should be set to disconnect capacitors at 110% of nominal voltage with a typical delay of 200 ms to avoid unnecessary operations during switching transients.

(4) Over-voltage protection on feeders should be set to trip the local circuit breaker at a voltage level of 120% of nominal voltage with a delay of one (1) to two (2) seconds.

6.1.2.9 Ancillary protection functions

(1) Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between protection devices and with bay equipment. A TransCo shall consider the following functions for all new protection system designs:

a. **Breaker fail / bus strip:** Each individual protection scheme shall be equipped with breaker fail/bus-strip functionality to ensure fast fault clearance in case of circuit breaker failure to interrupt fault current.

b. **Breaker pole discrepancy:** Breaker pole discrepancy protection compares, by means of breaker auxiliary contacts, state (closed or opened) of breaker main contacts on each phase. When a breaker on one phase is in a different position than breakers on remaining phases a trip command is issued after a specified time delay.
c. **Breaker anti-pumping:** To prevent repetitive closing of the breaker in case of fault in closing circuits, standard protection schemes should provide a breaker anti pumping timer. Circuit breakers are often equipped with their own anti pumping devices. In such cases anti pumping function is not required to be duplicated.

d. **Pantograph isolator discrepancy:** The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarms.

e. **Master relay:** Transformer and reactor protection schemes are equipped with latching master relay that require manual reset before the circuit breaker is enabled to close. The master relay is operated by *Unit* protection that indicates possibility of internal failure.

### 6.2 System protection requirements

#### 6.2.1 Under-frequency Load Shedding (UFLS)

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

2. **Under-frequency load shedding (UFLS)** relays shall be strategically installed on the *IPS* as determined by the *SO* in consultation with *TransCos*, *DisCos* and *Customers*. The respective asset owners shall pay for the installation and maintenance of these relays.

3. UFLS relays shall be tested periodically. *TransCos*, *DisCos* and *Customers* shall submit to the *SO* written reports of each such tests, within a *Month* of the test being done, in the format specified in the *Information Exchange Code*. The testing shall be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

#### 6.2.2 Out of step tripping

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

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

(3) DisCos shall determine and specify the out-of step tripping functionality to be installed at selected locations on their DSs.

6.2.3 Under-voltage load shedding

(1) 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.

(2) The SO shall determine and specify the under-voltage load shedding functionality to be installed at selected locations by TransCos.

6.2.4 Sub-synchronous Resonance (SSR) protection

(1) Although not a considerable threat to the IPS at the moment (small IPS with short lines), the possibility of SSR in the near future with interconnections to EAPP members and other countries in the region could result in conditions where SSR may become a problem requiring consideration. The SSR condition may arise on a power system where a generator is connected to the IPS through long series compensated TS lines. The potential for unstable interaction is sensitive to system topology and is greater with the higher degree of compensation and when larger thermal Units are employed. The SSR condition is addressed either through protection or mitigation:

a. In the case of protection, a suitable relay shall be deployed as part of the Unit’s protection that will lead to the Unit disconnection on detection of the SSR condition. The protection does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance.
b. Mitigation, on the other hand, acts to reduce or eliminate the resonant condition. Mitigation is needed only under conditions when it is desirable or essential to continue operation when the power system is at or near a resonant condition.

(2) New Units shall liaise with the relevant TransCo and SO regarding SSR protection studies. Least-cost solutions shall be determined by the relevant TransCo in collaboration with the prospective Generator and SO in accordance with the TS planning and development section of this Code (section 7), and implemented by the relevant asset owner.

6.2.5 Protection settings impact on network stability

(1) Minimum clearance times for protection in TransCo, DisCo or Customer networks will be determined on a case by case basis in order to ensure general system stability on the TS i.e. to maintain rotor angle, frequency and voltage stability.

(2) The EAPP Interconnection Code specifies the minimum fault clearance times on the EAPP Interconnected TS can be better than (but no longer than):

- a. 80 ms for faults on 400 kV and 500 kV
- b. 100 ms for faults at 230 kV and 220 kV
- c. 120 ms for faults at 132 kV and below

6.3 Protection systems performance monitoring

(1) To maintain a high level of protection performance and long term sustainability, TransCos shall monitor protection performance.

(2) The Authority audits as/when required.

(3) Each protection operation shall be investigated for its correctness based on available Information. Each TransCo and DisCo shall provide a report to Customers affected by a protection operation and/or the SO when requested to do so.
(4) The reliability of protection systems on the TS should be at least 99.5% (in line with EAPP requirements for the EAPP Interconnected TS).

7 Network planning and development

7.1 Transmission System (TS) planning

(1) This section specifies the technical, design and financial/economic criteria and procedures to be applied by a TransCo in the planning and development of its TS and to be taken into account by DisCos and Customers in the planning and development of their own systems. It also specifies the co-ordinated planning responsibility that the TSO takes on. It specifies Information to be supplied by Customers to TransCos, and Information to be supplied by TransCos to Customers as well as Information to be supplied to the TSO.

(2) The TSO shall assume the central co-ordinated responsibility of planning and development of the Transmission System.

(3) The development of a TS, will arise for a number of reasons including, but not limited to:

   a. A development on a Customer/DisCo system already connected to a TS.

   b. The integration of new Generators.

   c. The introduction of a new TS Substation or PoC or the modification of an existing connection between a Customer and the TS.

   d. The cumulative effect of a number of such developments referred to in clauses a, c and c above by one or more Customers/DisCos.

   e. The need to reconfigure, decommission or optimise parts of the existing network.

   f. Relief of network congestion.
(4) Accordingly, the development of a TS may involve work:

   a. At a Substation where Customer's/DisCo's Apparatus is connected to the TS.

   b. On TS lines or other Apparatus which join that Substation to the remainder of the TS.

   c. On TS lines, TS Substations or other facilities at or between points remote from that Substation.

(5) The time required for the planning and development of the TS will depend on:

   a. The type and extent of the necessary reinforcement and/or extension work

   b. The need or otherwise for statutory planning consent

   c. The associated possibility of the need for public participation

   d. The degree of complexity in undertaking the new work while maintaining satisfactory security and QoS on existing TSs and the overall TS.

7.1.1 Planning process

   (1) For the development of a specific TransCo's network, the TransCo shall follow a planning process divided into major activities as follows:


   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 acceptable justification criteria.

g. Requesting approval of the preferred option and initiating execution (the Authority/TSO).

### 7.1.2 Identifying the need for network investment

(1) A TransCo shall source relevant data from inter alia the following to establish the needs for network strengthening:

a. Integrated Development Plans e.g. National Integrated Resource Plan

b. Customer/DisCo information

c. System performance indices

d. TS network load forecast

e. Government development plans e.g. Electricity Development Strategy, National Energy Policy and Strategy, Electricity Master Plans


### 7.1.3 Forecasting the demand

(1) A TransCo is responsible for producing a TS demand forecast for the next five years and updating it annually and for estimating the load forecast for the next 10 years for the relevant TransCos section of the overall TS.

(2) A TransCo's TS demand forecast shall be determined for each PoS. Generation and import capacity plans shall be used to obtain the annual generation patterns.

(3) To forecast the maximum demand (MW) for each TS Substation on a TransCo’s network, a TransCo shall use DisCo and Customer load forecasts. Final loads are reconciled with data from various sources.
(4) The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to line up with the higher-level data.

(5) All DisCos and Customers shall annually, by the end of October, supply their 5-year ahead load forecast data and an estimate for the ten (10) years ahead demand as detailed in the Information Exchange Code.

7.1.4 Technical limits and targets for planning process

(1) The limits and targets against which proposed options are checked by a TransCo in collaboration with the TSO and SO shall include technical and statutory limits which must be observed, and other targets, which indicate that the overall TS is reaching a point where problems may occur. If technical or statutory limits are not achieved, alternative options shall be evaluated. If targets are not achieved, some options may be still acceptable as per the investment criteria.

7.1.4.1 Voltage limits and targets

(1) Technical and statutory limits are stated in Table 5.

(2) For convenience, standard voltages (U_M and U_N) are in included in Table 6.

<table>
<thead>
<tr>
<th>Description of parameter</th>
<th>Parameter symbol</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nominal continuous operating voltage on any bus for which equipment is designed</td>
<td>U_N</td>
</tr>
<tr>
<td>Maximum continuous voltage on any bus for which equipment is designed</td>
<td>U_M</td>
</tr>
<tr>
<td>Note: To ensure voltages never exceed U_m, the highest voltage used at sending-end busbars in planning studies should not exceed 0.98 U_m</td>
<td></td>
</tr>
<tr>
<td>Minimum voltage on Point of Common Coupling (PCC) during motor starting</td>
<td>0.85 U_N</td>
</tr>
<tr>
<td>Maximum voltage change when switching lines, capacitors, reactors, etc...:</td>
<td></td>
</tr>
<tr>
<td>At Maximum Fault Level</td>
<td>0.03 U_N</td>
</tr>
<tr>
<td>At Minimum Fault Level</td>
<td>0.075 U_N</td>
</tr>
<tr>
<td>Statutory voltage change on bus supplying Customer for any period longer</td>
<td>0.10 U_N</td>
</tr>
</tbody>
</table>
than 10 consecutive minutes (unless otherwise agreed in Connection Agreement) \( U_N \pm 10\% \)

<table>
<thead>
<tr>
<th>( U_N (kV) )</th>
<th>( U_M (kV) )</th>
<th>( (U_M-U_N)/U_N (%) )</th>
</tr>
</thead>
<tbody>
<tr>
<td>400</td>
<td>420</td>
<td>5.00</td>
</tr>
<tr>
<td>220</td>
<td>245</td>
<td>11.36</td>
</tr>
<tr>
<td>110</td>
<td>123</td>
<td>11.81</td>
</tr>
<tr>
<td>66</td>
<td>72.5</td>
<td>9.85</td>
</tr>
<tr>
<td>33</td>
<td>36</td>
<td>9.09</td>
</tr>
<tr>
<td>11</td>
<td>12</td>
<td>9.09</td>
</tr>
</tbody>
</table>

(3) Target voltages for planning purposes are as in Table 9.

<table>
<thead>
<tr>
<th>Description of parameter</th>
<th>Parameter symbol</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum steady state voltage on any bus not supplying a Customer With multiple feeder supplies:</td>
<td>0.95 ( U_N )</td>
</tr>
<tr>
<td>Minimum steady state voltage on any bus not supplying a Customer With single feeder supplies and after contingency for multiple feeder supplies:</td>
<td>0.90 ( U_N )</td>
</tr>
<tr>
<td>Maximum harmonic voltage caused by Customer at PCC:</td>
<td>QoS standard</td>
</tr>
<tr>
<td>Maximum negative sequence voltage caused by Customer at PCC:</td>
<td>QoS standard</td>
</tr>
<tr>
<td>Maximum voltage change due to load varying N times per hour</td>
<td>((4.5 \log_{10}N)%) OF ( U_N )</td>
</tr>
<tr>
<td>Maximum voltage decrease for a 5% load increase at receiving end of system (without adjustment):</td>
<td>0.05 ( U_N )</td>
</tr>
</tbody>
</table>

7.1.4.2 Other long-term planning targets

(1) **TS lines**: Thermal ratings of standard TS lines shall be determined and updated from time to time. The temperatures used to derive thermal ratings shall be 90°C for aluminium conductor steel reinforced (ACSR) lines providing a **Firm Supply** (under single contingencies), and 75°C for lines of copper or aluminium alloy or aluminium conductor steel reinforced lines not providing a **Firm Supply**. 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.

(2) **Transformers:** Standard transformer ratings shall be determined and updated from time to time using IEC specifications e.g. IEC 60076. The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors. If target loads are exceeded, the specific situation shall be assessed as it may be possible to defer transformer strengthening, depending on the actual transformer and on load conditions.

(3) **Shunt reactive compensation:**

a. Shunt capacitors shall be able to operate at 30% above their nominal rated current at $U_N$ to allow for harmonics and voltages up to $U_M$.

b. Reactive compensation, whether new or modified, may cause harmonic resonance problems. 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 overall TS, the Participant shall inform the SO before proceeding with the installation or modification.

c. Any TransCo wishing to install a new shunt device or series capacitor or modify the size of an existing shunt device or series capacitor, shall at his expense arrange for SSR, harmonic and protection coordination studies to be conducted to ensure that SSR will not be excited in any generator in the IPS.

(4) **Circuit breakers:**

a. Normal and fault current ratings for standard switchgear are determined and updated from time to time. These ratings, and the following limits specified for circuit breakers, shall not be exceeded:

   i. Single-phase breaking current: **1.15** times 3 phase fault current

   ii. Peak making current: **2.55** times 3 phase rms fault current
7.1.4.3 Reliability criteria

(1) A system cannot be made 100% reliable as planned and forced outages of components will occur, and multiple outages are always possible, despite having a very low probability of occurrence. From an economic point of view, optimum reliability is obtained when the cost involved in reducing the load not supplied by one kW is just equal to the value of this unsupplied kW to the economy or to the specific Customer involved. The appropriate degree of reliability depends on the probability of loss of supply and the probable amount of load not supplied when an outage does occur.

(2) All TransCos in collaboration with the TSO shall formulate long-term plans for expanding or strengthening the overall TS on the basis of the justifiable reliability and redundancy.

7.1.4.4 Contingency criteria

(1) A system meeting the N-1 contingency criterion must comply with all relevant technical limits outlined in section 7.1.4.1 of this Code (on voltage limits) and the applicable current limits, under all credible system conditions.

(2) For contingencies considered under various loading conditions it shall be assumed that the appropriate, normally-used, Generating Units are in service to meet the load and provide Operating Reserves as occurs during actual system operation i.e. appropriate generation pattern should be assumed. 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.

(3) The generation assumptions for the N-1 and N-2 network contingencies do not affect the final justification to proceed with investments, but merely check that the backbone of the network is still sufficient to meet an N-1 or N-2 contingency.

7.1.4.5 Integration of PSs

(1) When the integration of PSs is planned, the following network redundancy criteria shall apply:
a. **PSs of less than 25 MW**

i. With all connecting lines in service, it shall be possible to transmit the total output of the PS to the system for any system load condition. If the local area depends on the PS for voltage support, the connection shall be made with a minimum of two lines.

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

iii. If only a single line is used, it shall have the capability of being switched to alternative busbars and be able to go onto bypass at each end of the line.

b. **PSs of more than 25 MW**

i. With one connecting line out of service (N-1), it shall be possible to transmit the total output of the PS to the system for any system load condition.

ii. The smallest Unit installed at the PS shall only include Units that are directly connected to the TS and are centrally dispatched.

c. **Transient stability**

i. Transient stability shall be retained for the following conditions:

1. A three-phase line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous PS loading condition; or

2. A single-phase fault cleared in “bus-strip” times, with the system healthy and the most onerous PS loading condition; or

3. A single-phase fault, cleared in normal protection times, with any one line out of service and the PS loaded to average availability.
4. The above conditions will only apply to PSs larger than 25 MW. For PSs smaller than 25 MW, the conditions will only apply where it is economically justifiable.

5. The cost of ensuring transient stability shall be carried by the Generator if the optimum solution, as determined by the relevant TransCo in consultation with TSO, results in Unit or PS Apparatus being installed. In other cases, the relevant TransCo shall bear the costs and recover these as per the approved tariff methodology in the Tariff Code.

d. Busbar arrangements

i. Busbar layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass and not more than 25 MW of generation shall be connected to any bus section, even with one bus section out of service.

ii. The busbar layout shall ensure that no more than 25 MW of generation is lost as a result of a single contingency.

e. Information

i. To enable the relevant TransCo and TSO (via approval) to successfully integrate new PSs, detailed information is required per Unit and PS, as described in the Information Exchange Code.

7.1.5 Criteria for network investments

(1) The planning limits, targets and criteria form the basis for evaluation of the long-term development of the TS.

(2) A TransCo shall only invest in the TS when the required development meets the approved investment criteria specified in this section. However, it may be mutually agreed with affected Customers/DisCos to waive certain investments.
(3) Any one of the following investment criteria, each applicable under different circumstances, can be applied.

a. Assume a typical project life expectancy of 25 years except where otherwise dictated by plant life or project life expectancy.

b. The following key economic parameters shall have the Authority approved process of being established:

i. Discount rate (%)

ii. Cost of Unserved Energy (COUE)

7.1.5.1 Least economic cost criteria

(1) 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 Apparatus redundancy. The methodology requires that the cost of poor network services needs to be determined. These include the Customer Interruption Cost, load shedding, network constraints, poor QoS, etc. Statistical analysis of network outages is also required.

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

Value of improved QoS to Customers > Cost to provide improved QoS

(3) From the equation above it is evident that if the value of the improved QoS to the Customer is less than the cost to improve the QoS, the TransCo should not invest in the proposed project(s).

(4) The equation above can be stated differently as:

\[
p.a. \text{ value (RWF/kWh) } \times \text{ Reduction in EENS (kWh)} > p.a. \text{ cost (TransCo) reduce EENS (RWF)}
\]
(5) The reduction in *Expected Energy Not Served (EENS)* is calculated on a probabilistic basis based on the improvements derived from the investments.

(6) The *COUE* is a function of inter alia 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 *Customer* back-up generation.

(7) Figure 5 shows a typical load profile, while Figure 6 indicates the EENS for the time period considered. This is in the event of a load growing to 125 MVA whereas the firm transformer rating is 100 MVA.

![Figure 5 Example Load profile](image)

![Figure 6 Example load duration curve](image)

7.1.5.2 Cost reduction investments
(1) Proposed expenditure which is intended to reduce a TransCo’s costs e.g. shunt capacitor installations, telecommunication projects and equipment replacement which reduces 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:

a. Calculate the net-present value (NPV) of the proposed investment using the discounted cash flow method. This should be done by considering all cost reductions (e.g. savings in system losses) as positive cash flows, off-setting the required capital expenditure.

b. Perform a sensitivity analysis with respect to the amount of capital expenditure (estimated contingency amount), the annual average incremental cost of generation (when appropriate) and, future load growth scenarios is required.

c. A resulting positive NPV indicates that the investment is justified over the expected life of the proposed new asset.

7.1.5.3 Statutory investments

(2) This category of projects include the following:

a. Investments formally requested by government. This includes investments that will allow the country to become more self-sufficient in electricity supply and issues pertaining to the electrification of the country.

b. Increased connection with neighbouring countries in the region and EAPP requirements to allow the country’s ESI access to other markets in turn possibly reducing the overall cost of electricity.

c. Projects necessary to meet environmental legislation.

d. Expenditure to satisfy the requirements of the Labour Law specifically regulations in terms of occupational health and safety. This classification is intended to ensure the safety of operating and maintenance personnel who
are exposed to possible danger when busy with activities related to electricity transmission.

e. Possible compulsory contractual commitments.

f. Servitude acquisition

g. This category shall not be used for justifying projects that are not of economic benefit to the country.

7.1.6 Development Investigation Reports

(1) *TransCos* shall compile, before any development of the *TS* is approved, a detailed Development Investigation Report which should be submitted to the Authority/TSO. 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.

(2) The Development Investigation Report shall be approved in collaboration with the relevant *TransCo* and TSO/Authority before any development commences.

7.1.7 Mitigation of network constraints

(1) *TransCos* have the obligation to resolve network constraints.

(2) Network constraints (“congestion”) shall be regularly reviewed by *TransCos* in collaboration with the TSO. Economically optimal plans shall be put in place around each constraint, which may involve investment in the TS, the purchase of constrained *Generation, Ancillary Services* or other agreed upon solutions.
7.1.8 Special requirements for increased reliability

(1) Should a Customer require a more reliable or safer connection than the one provided for by a TransCo (a Premium Supply), and the Customer is willing to pay the total cost of providing the increased reliability in the form of an additional connection charge, the relevant TransCo shall meet the requirements at the lowest overall cost.

(2) The Premium Supply and the additional connection charges shall be approved in collaboration with the relevant TransCo, Customer and the Authority/TSO before any development commences.

7.1.9 Transmission System Development Plans

(1) All TransCos shall prepare TS development plans with a minimum window period of five (5) years indicating the major capital investments planned (but not yet necessarily approved). These TS Development Plans shall be reviewed at the least every 2 years by the TSO.

(2) The TS Development Plans shall be based on all Customer requests received at the time of preparing the plans, network load forecasting, as well as TransCo initiated projects.

(3) TransCos shall submit their TS development plans to the TSO/the Authority who will collaboratively approve them. This will allow for centralised coordinated TS planning and development as well as a harmonised approach to regional EAPP interconnections.

(4) TransCos shall publish the latest approved TS Development Plans.

(5) The TSO shall submit a consolidated TS Development Plan to the Authority for approval

(6) The latest approved consolidated TS Development Plan shall be published by the TSO.

7.1.10 EAPP planning coordination
(1) The TSO shall be responsible for submitting the required *Power Balance Statement* and *TS Capability Statement* as outlined in the *EAPP Interconnection Code*.

(2) The TSO shall provide accurate and appropriate *Apparatus* characteristics and system data for modelling and simulation purposes as required in the *EAPP Interconnection Code*.

(3) The *Power Balance Statement* comprises a forecast of the expected demand and *Generation* over the planning horizon (10 years). This should be submitted by the TSO with the required information as detailed in the *EAPP Interconnection Code* timorously.

(4) The required *TS Capability Statement* outlines the capability of the TS to support the required energy flows across the Rwandan TS and for cross-border interconnections. The TSO shall submit the TS Capability Statement using data from the common *EAPP* database and shall ensure that the planning process is based on a common set of principles agreed upon beforehand.

(5) The *Power Balance Statement* and *TS Capability Statement* should be submitted in collaboration with the *EAPP Sub-Committee on Planning*.

### 7.2 Distribution System (DS) planning

(1) Similar to section 7.1 on TS planning and development, this section specifies the technical, design and economic criteria and procedures to be applied by a *DisCo* in the planning and development of its *DS* and the involvement of the *Authority* in general co-ordination and regulation of the overall *DS*.

#### 7.2.1 Framework

(1) *DisCos* shall source/develop relevant data from various sources including inter alia the latest versions of the following to establish the need for network strengthening:

a. Integrated Development Plan
b. *Customer information*

c. System performance indices

d. Distribution network load forecast

e. Government development plans e.g. Electricity Development Strategy, National Energy Policy and Strategy, Electricity Master Plan

f. *Customer* development plans

(2) *DisCos* shall annually compile a 10-year load forecast for a *DisCo’s* incoming *Points of Supply* including *DisCo’s* cross-boundary connections to the relevant *TransCo’s* network to which they are connected.

(3) *DisCos* shall be responsible for compiling network development plans with a minimum window period of five (5) years. These network development plans shall be reviewed at the least every 2 years by the *Authority*. The aim of network development plans is to ensure a capable network and should therefore include all relevant activities such as electrification and refurbishment. Such plans should be drawn up taking into account only available *Information*. Unexpected loads or *Customer* requests can be retrospectively added to the plan during the review process.

(4) The network development plans and post release changes shall be submitted to the *Authority*.

(5) All *DisCos* approved network development plans shall be published.

(6) *TransCos* and the *TSO* shall use the *Information* in approved *DisCo* development plans to perform their network planning responsibilities.

### 7.2.2 Network investment criteria

#### 7.2.2.1 Introduction
(1) *Distribution tariffs* should be sufficient to allow the necessary investments in the networks to be carried out in a manner allowing these investments to ensure the viability of the networks.

(2) *DisCos* shall invest in the *DS* when the required development meets the technical and investment criteria specified in this section.

(3) The need to invest must first be decided on technical grounds. All investments must be the least life-cycle cost technically acceptable solution, that is, it shall provide for *Standard Supply*:

   a. Minimum QoS requirements defined in *this Code* and by *the Authority*.

   b. Minimum reliability and operational requirements as determined by this *Code* and by *the Authority*.

(4) The investment choice must be justified by considering technical alternatives on a least life cycle cost approach. Least life cycle cost is the discounted least cost option over the lifetime of the equipment, taking into account the technical alternatives for investment, operating expenses and maintenance.

(5) Calculations to justify investment shall assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

(6) The following key economic and financial parameters shall be determined by *the Authority*:

   a. Discount rate

   b. *Customer* interruption cost *i.e.* *Cost of Unserved Energy* (*COUE*).

   c. Other *Authority* approved economic parameters.

### 7.2.2.2 General Investment Criteria
(1) Investments should be prudent (justified) as a least life-cycle cost solution after taking into account, where applicable, technical alternatives that consider the following:

a. The investment that will minimise the cost of the energy supplied and the Customer interruption cost i.e. COUE.

b. Current and projected demand on the network.

c. Reduction of life-cycle costs e.g. reduction of technical losses, operating and maintenance costs and telecommunication projects

d. Current condition of assets and refurbishment and maintenance requirements.

e. Demand and supply options.

f. Any associated risks.

(2) Shared network investments shall be evaluated on the least-life-cycle economic cost. Economic cost will consider the least life cycle total cost of the electricity related investment to both DisCos and the Customer.

(3) Investments made by DisCos dedicated to a particular Customer shall be evaluated on a least life-cycle DisCo cost. DisCo cost will consider only the least-life cycle investment cost to the DisCo.

(4) DisCos shall evaluate investments in terms of the following categories:

a. Shared network investments.

b. Dedicated Customer connections.

c. Statutory investments.

d. International connections (cross-border connections)
7.2.2.3 Least economic cost criteria for shared network investments

(1) Shared network investments are:

a. Investments on shared infrastructure (not-dedicated) assets.

b. Investments required to provide adequate upstream network capacity.

c. Investments required to maintain or enhance supply to attain the relevant QoS and technical limits or targets applicable to DisCos in this Code.

d. Refurbishment of existing standard dedicated connection assets.

(2) All shared network investments are to be justified on least economic cost. In determining the least economic cost for shared network investments the investment must be justified to minimise the cost to the electricity industry and not just to the DisCo.

7.2.2.4 Least life cycle cost criteria for standard dedicated Customer connections

(1) A standard connection (Standard Supply) is defined as the lowest life-cycle costs for a technically acceptable solution and will be charged for as described in the in the Tariff Code.

(2) Dedicated Customer connections are:

a. New connection assets created for the sole use of a Customer to meet the Customer’s technical specifications.

b. Dedicated assets are assets that are unlikely to be shared in the DisCo’s planning horizon by any other Customer.

(3) All dedicated connection investments are to be justified on the technically acceptable least life-cycle costs.

(4) Where the investment meets the least life-cycle cost, the Customer shall be required to pay a standard connection charge as described in the Tariff Code.
(5) For certain Customer groupings, as approved by the Authority, the investments shall be justified collectively as per Customer grouping and not per Customer.

(6) The DisCo will refurbish / replace / reconfigure all Apparatus in terms of its standards to meet standard QoS and technical limits criteria at no cost to the Customer and this will allowed to be recovered in the use-of-system (network charges). This will be a non-discriminatory approach where no consideration will be given to the special or unique requirements of the Customer.

7.2.2.5 Investment criteria for premium Customer connections

(1) The DisCo shall investigate the additional requirements for a premium connection (Premium Supply) and will provide a least life-cycle cost solution.

(2) If the Customer agrees to the solution, all costs to meet the Customer requirement in excess of what is considered the least life-cycle cost investment is payable as a premium connection charge by the Customer as described the Tariff Code. Such costs shall be appropriately pro-rated, if a portion of the investment can be justified based on improved reliability or reduction of costs.

(3) The refurbishment of identified premium connection assets will occur when the equipment is no longer reliable or safe for operation. The DisCo must justify the need for refurbishment of the premium assets to the Customer, and the Customer must agree to the continuance of the Premium Supply.

(4) At the time of refurbishment, should the Customer have any requirements that cannot be met in terms of clause (5) in section 7.2.2.4, any additional investment will be seen as a Premium Connection.

(5) Where the refurbishment of a supply in accordance with current technical standards will result in additional cost to the Customer, an engineering solution that minimises the sum of the DisCo’s and the Customer’s costs will be found. This least economic cost option will be implemented but any expenditure in excess of the DisCo least life-cycle cost solution (as per section 7.2.2.2 and 7.2.2.4) will be borne by the Customer through a new
Premium Connection charge and shall not be recovered through use-of-system (network) charges.

7.2.2.6 Statutory or strategic investments

(1) DisCos will be obligated to make statutory investments in terms of clause (3) below.

(2) Statutory and strategic investments will be motivated on a least economic cost basis, as defined in section 7.2.2.3 of this Code.

(3) Strategic and statutory projects include the following:

a. Investments formally requested in terms of published government policy but not considered dedicated Customers as under section 7.2.2.4.

b. Projects necessary to meet national environmental legislation.

c. Expenditure to satisfy the requirements on the DisCo to comply with appropriate Occupational Health and Safety legislation. This is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to the ESI.

d. Possible compulsory contractual commitments.

e. Servitude acquisition.

f. New Embedded Generators (EGs).

7.2.2.7 Investment criteria for international connections

(1) The investment for international Customers shall be in terms of the criteria set out for a dedicated connection, but the DisCo shall charge a connection charge that ensures that there is no cross border subsidies, as set out in the Tariff Code.
8 Other Network Services

(1) Other Network Services are those mandatory services to ensure a standard of supply that meets QoS, reliability and safety standards. Other Network Services may be competitive or provided by TransCos/DisCos as a monopoly service.

(2) Other Network Services include the following:

a. Design and construction of dedicated Customer connections.

b. Recoverable works such as inspection and maintenance of non-DisCo and/or non-Transmission owned installations, line relocation and other requested recoverable works.

c. The construction and maintenance of public lighting assets.

(3) For Other Network Services, Customers, Generators and EGs shall be allowed to choose a contractor other than the TransCo/DisCo or a contractor appointed by the TransCo/DisCo, provided that an agreement is mutually reached between the TransCo/DisCo and the Customer, Generator or EG prior to the project being undertaken. Conditions to be included in the agreement can include (amongst other conditions agreed upon):

a. The assets the Customer, Generator or EG is allowed to work on or not.

b. The terms and conditions for the approval of the network design.

c. The terms and conditions for the inspection and the work done prior to any agreement to take over and/or commission the connection.

d. The charges to be raised by the TransCo/DisCo for monopoly related services.

(4) The fees charged by the TransCo/DisCo for Other Network Services may be regulated by the Authority.
9 **Network maintenance**

(1) All *Participants* shall operate and maintain the *Apparatus* owned by them. The cost of such operations and maintenance shall be borne by the respective *Participants* unless such *Apparatus* is proved to have been damaged by a negligent act or omission of a *Participant* other than the owner, its agents or employees, in which case the responsible *Participant* shall be liable for the costs of repairing such damage. If no agreement can be found as to who damaged the *Apparatus* under consideration, the dispute resolution process outlined in the *Governance Code* shall be followed.

(2) *Participants* shall monitor the performance of their *Apparatus* and take appropriate action where deteriorating trends are detected.

(3) Maintenance scheduling shall be done in accordance with the *System Operations Code*.

(4) *TransCos* and *DisCos* shall agree in writing with *Customers*, details of any special maintenance requirements as well as maintenance co-ordination requirements per *Transmission Substation* and *Distribution Substation* respectively. *TransCos* and *DisCos* shall provide *Customers* with details of maintenance plans and practices upon request, if these affect the quality of a connection.

(5) *The Authority* can audit maintenance procedures as/when required.
Appendix A  Generator Connection Conditions
Table 8 Summary of the requirements applicable to non-hydro generating Unit

<table>
<thead>
<tr>
<th>Grid Code Requirement</th>
<th>Unit Size $S_{MCR}$ (MVA rating)</th>
<th>$S_{MCR} &lt; 1$</th>
<th>1 to 20</th>
<th>20 to 40</th>
<th>40 to 60</th>
<th>60 to 100</th>
<th>$S_{MCR} \geq 100$</th>
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<thead>
<tr>
<th>Grid Code Requirement</th>
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Key:
- D - Depends on system requirements
- A - If agreed upon
- PS - PS
- N<sub>Unit</sub> - Number of Unit at a PS
Table 9 Summary of the requirements applicable to hydro generating Unit

<table>
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<tr>
<th>Grid Code Requirement</th>
<th>Unit Size $S_{MCR}$ (MVA rating)</th>
<th>$S_{MCR} &lt; 1$</th>
<th>1 to 20</th>
<th>20 to 40</th>
<th>40 to 60</th>
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<tr>
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<tr>
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<td>If $PS &gt; \text{Largest single contingency}$</td>
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<td>If $PS &gt; \text{Largest single contingency}$</td>
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Key:
- D - Depends on system requirements
- A - If agreed upon
- PS - $PS$
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$N_{Unit}$ - Number of Unit at a PS
Appendix B  Sample Generator / Embedded Generator Application Form
**Note:** This form (or a variant thereof as defined by each TransCo and/or DisCo) is to be completed in full by all prospective Generators or Embedded Generators and returned to the relevant DisCo/TransCo together with additional requested information for review.

**Generator / Embedded Generator Application Form**

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   Telephone:  
   Facsimile:  
   Email: |
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   Project Location:  
   Project Contact Name & Telephone Number:  
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<tr>
<td></td>
<td>Projected In-Service Date of Embedded Generator:</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th><strong>Site plan:</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>5</td>
<td>Please attach site plan to show inter alia scaled mapping of existing lot lines, road crossings, water services, electricity infrastructure</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th><strong>Preliminary design (please list as attached):</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>6</td>
<td>Design to show inter alia number and size of generators, transformer/s, proposed connection point/s, isolating devices, protection schemes</td>
</tr>
<tr>
<td><strong>Generator specifications:</strong></td>
<td></td>
</tr>
<tr>
<td>-----------------------------</td>
<td></td>
</tr>
<tr>
<td>Manufacturer:</td>
<td></td>
</tr>
<tr>
<td>Fuel type:</td>
<td></td>
</tr>
<tr>
<td>Rated MVA:</td>
<td></td>
</tr>
<tr>
<td>Rated MW:</td>
<td></td>
</tr>
<tr>
<td>Rated Voltage:</td>
<td></td>
</tr>
<tr>
<td>Rated Power Factor:</td>
<td></td>
</tr>
<tr>
<td>Inertial Constant:</td>
<td></td>
</tr>
<tr>
<td>Maximum MVAR Limit:</td>
<td></td>
</tr>
<tr>
<td>Neutral to Earth Resistance in Ohms:</td>
<td></td>
</tr>
<tr>
<td>$X_d$ – Synchronous reactance in p.u:</td>
<td></td>
</tr>
<tr>
<td>$X'd$ - Direct Axis transient reactance in p.u:</td>
<td></td>
</tr>
<tr>
<td>$X'd$ – Direct axis sub-transient reactance in p.u:</td>
<td></td>
</tr>
<tr>
<td>$X_2$ – Negative sequence reactance in p.u:</td>
<td></td>
</tr>
<tr>
<td>$X_0$ – Zero sequence reactance in p.u</td>
<td></td>
</tr>
</tbody>
</table>
8 | **Generator and Unit transformer specifications:**
- Voltage and power ratings:
- Windings configuration:
- Neutral earth resistors or reactors:
- Positive and zero sequence impedances in p.u:
  - R1:
  - X1:
  - RO:
  - XO:

9 | **Expected Consumption in MWh per year**
(details to be clarified with the relevant *DisCo/TransCo*):

10 | **Future Site Developments plans:**

11 | **Proposed Plant Design:**
- Operating characteristics

12 | **Any other additional relevant information (please list as attached):**
I request the Transmitter/DisCo to proceed with a preliminary review of this Embedded Generator/Generator connection application and I agree to pay the cost associated with completing this review.

I further consent to the Transmitter/DisCo providing this information to other Participants (TransCos, DisCos, the Authority, SO) as required (with prior approval from myself).

Name: ___________________________ Signature: ____________________

Title: ___________________________ Date: ________________________
Appendix C  Transmission/Distribution service application form
## Transmission/Distribution Service Application Form

Note: Where indicated, shaded areas are for completion by the Transmitter (TransCo)/Distributor (DisCo). Please provide any additional detail in the areas designated for notes.

<table>
<thead>
<tr>
<th>Required Service:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Transmission/Distribution</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applicant Contact Person 1:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Applicant's preferred form of address</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applicant Contact Person 1 Initials, Surname and Job Title:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Initials:</td>
<td></td>
</tr>
<tr>
<td>Surname:</td>
<td></td>
</tr>
<tr>
<td>Job Title:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applicant Contact Person 2:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Applicant's preferred form of address</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Applicant Contact Person 2 Initials, Surname and Job Title:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Initials:</td>
<td></td>
</tr>
<tr>
<td>Surname:</td>
<td></td>
</tr>
<tr>
<td>Job Title:</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Company Name:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Officially registered company name</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Co/CC Reg. Number:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Officially registered company number</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Person 1 Telephone 1:</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Person 2 Telephone 1:</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Person 1 Telephone 2/Mobile:</th>
<th></th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Person 2 Telephone 2/Mobile:</th>
<th></th>
</tr>
</thead>
</table>

| Person 1 Fax |  |

| Person 2 Fax |  |
Person 1 E-Mail: 

Person 2 E-Mail: 

Applicant’s Physical Address: 

Applicant’s Postal Address: 

Physical connection to the Transmission system (Y/N): 

If not, indicate nature of business e.g. Trader: 

Type of quote required (please tick) 

Feasibility: 

Firm: 

Notes: 

Additional Applicant information
The following fields will be completed by the TransCo/DisCo

<table>
<thead>
<tr>
<th>Applicant ID:</th>
<th>Applicant type:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unique reference number</td>
<td>e.g. Individual, company, partnership, other</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Existing Customer:</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>(Y/N)</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Application Date</th>
<th>Connection Voltage</th>
<th>Capacity of connection:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Initial application date</td>
<td>kV</td>
<td>MVA</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Requested completion date</th>
<th>Estimated monthly consumption/generation:</th>
</tr>
</thead>
<tbody>
<tr>
<td>When applicant wants connection to network</td>
<td>MWh</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Temporary connection:</th>
<th>Owner or tenant</th>
</tr>
</thead>
<tbody>
<tr>
<td>If temporary, num. of months for which connection is required</td>
<td>Applicant owns/rents property for this application</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Physical connection address (POS)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geographical location of connection</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Longitude</th>
<th>Latitude</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Application category (please circle)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Industrial</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other (please specify):</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Nearest existing Transmission Substation:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation closest to Physical connection address</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Other Transmission System Connections:</th>
<th>Standard or premium connection:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Does Customer have other transmission connections/points of supply?</td>
<td></td>
</tr>
</tbody>
</table>

Special instructions:

<table>
<thead>
<tr>
<th>Cancellation Date</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>d       d  m m y y y</td>
</tr>
</tbody>
</table>

Reason for cancellation:

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

The following fields will be completed by the TransCo/DisCo
### Application ID:
Unique no for current application

### POS ID:
Unique no applicable to point-of-supply

#### Application Type ID:
- **NEW**
  - New connection
- **INCR**
  - Increase of connection to:
- **DECR**
  - Decrease of connection to:
- **CHANGE**
  - Change of Customer only
- **LINES**
  - Existing lines to be moved

<table>
<thead>
<tr>
<th>MVA</th>
<th>MVA</th>
<th>MVA</th>
<th>MVA</th>
<th>MVA</th>
<th>MVA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Size of required supply</td>
<td>Size of required supply</td>
<td>Size of required supply</td>
<td>Current supply</td>
<td>Current supply</td>
<td>Size of required supply</td>
</tr>
</tbody>
</table>

#### Priority request indicator:
Low / Normal / High

#### Priority request reason
Motivation for high/low indicators

#### Customer major activity:

#### Project ID:

#### Grid Region:

#### Application remarks:

#### Other Reference numbers:
Other applicant applications and/or points of connection

#### Quotation Date:
Date on which application was completed

#### Agreement Date:

<table>
<thead>
<tr>
<th>Date on which agreement was completed</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Connection fee amount (RWF)</td>
<td></td>
</tr>
<tr>
<td>Connection fee reference number</td>
<td></td>
</tr>
<tr>
<td>Unique number</td>
<td></td>
</tr>
<tr>
<td>Connection fee payment date:</td>
<td>d d m m y y y</td>
</tr>
<tr>
<td>Date on which receipt of connection payment</td>
<td></td>
</tr>
</tbody>
</table>
Appendix D  Surveying, monitoring and testing of generators
D-1 Introduction

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

a. Compliance by PSs with the Grid Code.

b. Provision by PSs of Ancillary Services which they are required or have agreed to provide.

D-2 Request for surveying, monitoring or testing

(1) The SO may at any time issue an instruction requiring a PS to carry out a test (although it may not do so more than twice in any calendar year in respect of any particular PS except to the extent that it can on reasonable grounds justify the necessity for further tests or unless the further test is a re-test), at a time no sooner than 48 hours from the time that the instruction was issued, to demonstrate that the relevant PS complies with the Grid Code requirements.

D-3 Ongoing monitoring of a Unit’s performance

(2) Generators shall monitor each of their Units during normal service to confirm ongoing compliance with the applicable parts of this Code. Any material deviations detected must be reported to the SO within five working days.

(3) Generators shall keep records relating to the compliance by each of their Generating Units with each section of this Code applicable to that Generating Unit, setting out such information as the SO and/or TransCo reasonably requires for assessing power system performance (including actual Unit performance during abnormal conditions).

(4) Within one month after the end of June and December, Generators shall provide the SO with a report detailing the compliance or non-compliance in any material respect by each of their Generating Units with every section of
this Code during the previous six-month period. The template for this appears as an Appendix in the Information Exchange Code.
## D-4 Procedures

### D-4.1 Unit Protection System Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Protection function and setting integrity study</td>
<td>4.1.1</td>
</tr>
</tbody>
</table>

**APPLICABILITY AND FREQUENCY**

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

**Routine review:** All *generators* to confirm compliance every six years.

**PURPOSE**

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

**PROCEDURE**

**Prototype:**

1. Establish the system protection function and associated trip level requirements from the *System Operator*.
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 and stability calculations for each protection function.
5. Convert protection tripping levels for each protection function into a per unit base.
6. Consolidate all settings in a 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 on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers’ information into one document.
11. Submit to the System Operator for its acceptance and update.
12. Provide the System Operator with one original master copy and one working copy.

Review:
1. Review Items 1 to 10 above.
2. Submit to the System Operator for its acceptance and update.
3. Provide the System Operator with one original master copy and one working copy.

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

Submit a report to the System Operator one month after commissioning for a prototype study or six-yearly for routine tests.
<table>
<thead>
<tr>
<th>Protection integrity tests</th>
<th>4.1.1</th>
</tr>
</thead>
</table>

**APPLICABILITY**

**Prototype test:** All new *power stations* coming on line and all other *power stations* after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified.

**Routine test:/Reviews:** All *units* on:
- item 1 below: Review and confirm every 6 years
- item 2, and 3 below: at least every 12 years.

**PURPOSE**
To confirm that the protection has been wired and functions according to the specifications.

**PROCEDURE**
1. Apply final settings as per agreed documentation to all protection functions.
2. With the *unit* off load and de-energised, 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.
5. With the *unit* at nominal speed, excite *unit* slowly, recording voltages on all relevant protection functions. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses.
<table>
<thead>
<tr>
<th>ACCEPTANCE CRITERIA</th>
</tr>
</thead>
<tbody>
<tr>
<td>All protection functions are fully operational and operate to required levels within the relay OEM allowable tolerances.</td>
</tr>
<tr>
<td>Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard.</td>
</tr>
<tr>
<td>Submit a report to the System Operator one month after test.</td>
</tr>
</tbody>
</table>
## D-4.2 Excitation System Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excitation and setting integrity study</td>
<td>4.1.2</td>
</tr>
</tbody>
</table>

### APPLICABILITY AND FREQUENCY

**Prototype study:** All new power stations coming on line or power stations at which major refurbishment or upgrades of excitation systems have taken place. Also, where localised changes or modifications are done, only affected part or parts shall be covered.

**Routine review:** All power stations to confirm compliance every six years.

### PURPOSE

To ensure that the excitation system in the power station is co-ordinated and aligned with the system requirements.

### PROCEDURE

**Prototype:**

1. Establish the excitation system performance requirements from the System Operator.
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 the System Operator 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 and alarms.
5. Confirm the stability of the excitation system for relevant excitation system operating conditions.
6. Document the details of the trip levels, stability calculations for each setting and function.
7. Convert the settings for each function into a 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 the signal source.
10. Document the tripping functions for each tripping on one tripping logic diagram.
11. Consolidate the detailed setting calculations, model, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers’ information into one document.
12. Submit to the System Operator for its acceptance and update.
13. Provide the System Operator with one original master copy and one working copy.

**Review:**
Review items 1 to 10 above.
Submit to the System Operator for its acceptance and update.
Provide the System Operator with one original master copy and one working copy update if applicable.

**ACCEPTANCE CRITERIA**

The excitation system is set to meet the necessary control requirements in an optimised manner for the performance of the transmission and power station plant. The excitation system operates stable both internally and on the network.

Submit a report to the System Operator one month after commissioning for a prototype study or five to six-yearly for routine tests, within one month after expiry of the due date.
### 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. Also, after localised modifications or works have been carried out to the plant that will affect this performance.

**Routine test:** All generators to perform tests on each unit 6-yearly after a major overhaul of plant.

**PURPOSE**

To confirm that the excitation system performs as per the specifications.

**PROCEDURE**

- With the unit off line, carry out frequency scan/bode plot tests on all circuits in the excitation system critical to the performance of the excitation system.
- With the unit 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 and voltage response.
- With the unit synchronised and loaded, carry out the small signal performance tests according to IEE 421.2 of 1990. Also carry out power system stabiliser tests and determine damping with and without power system stabiliser.
- Document all responses.

**ACCEPTANCE CRITERIA**

The excitation system meets the necessary control requirements in an optimised manner for
the performance of the transmission and power station plant as specified. The excitation system operates stably both internally and on the network. The power system stabilisers are set for optimised damping.
## D-4.3 Unit Reactive Power Capability Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactive power capability</td>
<td>4.1.3</td>
</tr>
</tbody>
</table>

**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/reviews:** Confirm compliance every 6 years.

**PURPOSE**
To confirm that the reactive power capability specified is met.

**PROCEDURE**
The unit will be required to regulate the voltage on the HV busbar to a set level.

**ACCEPTANCE CRITERIA**
The unit shall maintain the set voltage within ±5% of the capability registered with the System Operator for at least one hour.

Submit a report to the System Operator one month after the test.
### D-4.4  PS Multiple Unit Trip Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Multiple-unit tripping (MUT) tests, study and survey</td>
<td>4.1.4</td>
</tr>
</tbody>
</table>

#### APPLICABILITY

**Prototype tests/study/survey:**

- **New power stations** coming on line: items 1 to 5 below.
- **Power stations** at which major modifications or changes have been implemented on plant critical to *multiple-unit tripping*: applicable item(s) listed 1 to 5 below.

**Routine assessment:** All *power stations*: item 5 below every 6 years

**Routine testing:** All *power stations*. Review and confirm the status every 6 years, and test if required.

#### PURPOSE

To confirm that a *power station* is not subjected to unreasonable risk of *MUT* as defined in the Network Code, section 3.1.5.

#### PROCEDURE AND ACCEPTANCE CRITERIA

1. **Emergency supply isolation test:**

   On all emergency supplies (e.g. DC supplies) common to more than one *unit*, isolate the supply for at least one second, with the *unit* running at full load under normal operating conditions. Tests are carried out on one *unit* at a time. Where two supplies feed one common load, isolation of one supply at a time will be sufficient. Confirm that the *unit* or part of the *unit* plant
does not trip. No change in the unit output shall take place. Document results. This test does not apply to nuclear plant.

2. Disturbance on DC supply survey:

On all DC supplies common to more than one unit, carry out a survey of the immunity of all devices that are part of tripping circuits, to supply voltage according to IEC specifications. All devices on DC supplies common to more than one unit that form part of tripping circuits or that can cause tripping or load reduction on a unit must comply with IEC specification. Document findings.

3. Uninterruptible power supplies (UPS) integrity testing:

On all UPS’s supplying critical loads that can cause tripping of more than one unit within the time zones specified in 3.1.5, isolate the AC supply to the UPS for a period of at least one minute. Where two UPS’s supply one common load, one UPS at a time can be isolated. Load equipment must resume normal operation. Document results. This test does not apply to nuclear plant.

4. Earth mat integrity inspection and testing:

Carry out an inspection and tests on all parts of the power station earth mat that is exposed to lightning surge entry and in close proximity to circuits vulnerable to damage that will result in tripping of more than one unit within the time zones specified in 3.1.5 (e.g. chimney on fossil fuel power stations or penstock on hydro power stations) Confirm that all the earthing and bonding are in place, and measure resistances to earth at bonding points. Document findings and results.
5. **MUT** risk assessment:

Identify all power supplies, air supplies, water supplies and other supplies/systems common to more than one *unit* that are likely to cause the tripping of more than one *unit* within the **MUT** categories specified in section 3.1.5. Calculate the probability of all the **MUT** risk areas for the *power station*. Document all findings, listing all risks and probabilities.

No unreasonable **MUT** items as listed in 3.1.5 shall be present.

Report to be submitted to the *System Operator* one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.
## D-4.5 Governing System Grid Code Requirements

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Governing response tests</td>
<td>4.1.5</td>
<td></td>
</tr>
</tbody>
</table>

### 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 units to be monitored continuously. Additional tests may be requested by the System Operator, acting reasonably but not more than 2-yearly.

### PURPOSE
To prove that the unit is capable of the minimum requirements for governing.

### PROCEDURE
- Frequency or speed deviation to be injected on the unit for ten minutes.
- Real power output of the unit to be measured and recorded.

### ACCEPTANCE CRITERIA
Minimum requirements of the Grid Code are met.
D-4.6 Unit Restart after Station Blackout Capability Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Restart after station blackout survey</td>
<td>4.1.6</td>
</tr>
</tbody>
</table>

**APPLICABILITY**

Prototype survey: New power stations or power stations at which modifications have been carried out on plant critical to multiple-unit restarting.

**PURPOSE**

To confirm that a power station can restart units simultaneously, according to the criteria outlined in section 3.1.7, after a station blackout condition.

**PROCEDURE**

1. Plant capacity survey:

   Identify all supply systems common to two or more systems (e.g. power supplies, crude oil, air, demin water).
   Determine the quantity and supply rate required to simultaneously restart the number of units specified in section 3.1.7.
   Document critical systems, required stock, study details and findings.

2. Survey of available stock:

   For each of the applicable critical systems identified, document the average stock for the year, minimum stock and duration below critical stock levels.

**ACCEPTANCE CRITERIA**

More than 95% of the time over the year, all stocks are above critical levels.
Report to be submitted to the System Operator one month after commissioning. Routine survey reports to be submitted one month after expiry of the due date.
D-4.7  PS Black Start Capability Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
<th>APPLICABILITY</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black starting</td>
<td>4.1.7</td>
<td></td>
</tr>
</tbody>
</table>

**Routine test**: Power stations that have contracted under the ancillary services to supply black start services. Once every three years for a partial test and once every six years for a full test.

**PURPOSE**
To demonstrate that a black start power station has such capability.

**PROCEDURE**
- The relevant unit of the power station shall be disconnected from the system and shut down.
- All external auxiliary supplies to the relevant unit shall be disconnected.
- In the case of a station black start, the designated unit, shall be started with the relevant unit board being energised from an independent auxiliary supply within the power station. This auxiliary supply has to be in shutdown mode until the alternator is at a standstill.
- The unit shall be re-synchronised to the IPS.

**ACCEPTANCE CRITERIA**
The unit shall be able to re-synchronise to the IPS within 4 hours from the start of the test.

A partial test shall involve:
- Isolation of the unit
- Starting up of the unit from an independent source and
- Energizing a defined portion of the transmission / distribution system.
A full test shall involve:

- Isolation of the unit
- Starting up of the unit from an independent source
- Energizing a defined portion of the transmission / distribution system and
- The subsequent loading of the unit to prove blackstart capability.

Submit a report to the System Operator one month after the test.

The System Operator may request a full re-test in the event of a failed test or to re-test functions that did not meet test requirements.
### D-4.8  External Supply Disturbance Withstand Capability Grid Code Requirement

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Reference</th>
<th><strong>APPLICABILITY</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage and frequency deviation</td>
<td>4.1.8</td>
<td><strong>Prototype survey/test</strong>: New power stations coming on line or power stations in which major modifications have been made to plant that may be critical to system supply frequency or voltage magnitude deviations: item 2 for plants using dip proofing inverters (DPI).</td>
</tr>
<tr>
<td></td>
<td></td>
<td><strong>Routine testing and survey</strong>: All power stations: review items 1 to 3 every six years. Carry out item 3 every six years.</td>
</tr>
</tbody>
</table>

**PURPOSE**

To confirm that the power station and its auxiliary supply loads conform to the requirements of supply frequency and voltage magnitude deviations as specified in section 3.1.9.

**SCOPE OF PLANT OR SYSTEMS**

**Critical plant**: Equipment or systems that are likely to cause tripping of a unit or parts of a unit or that are likely to cause a multiple-unit trip (MUT).

**PROCEDURE AND ACCEPTANCE CRITERIA**

1. **Frequency deviation survey**:

   Carry out a survey on the capability of critical plant confirming that it will resume normal operation for frequency deviations as defined in section 3.1.6.
A unit or power station shall not trip or unduly reduce load for system frequency changes in the range specified in section 3.1.6.

2. **Voltage magnitude deviation survey:**
Carry out a survey on the capability of critical plant confirming that it will resume normal operation for voltage deviations as defined in section 3.1.7. Document findings. Also consider protection and other tripping functions on critical plant. Document all findings.

A unit or power station must not trip or unduly reduce load for system voltage changes in the range specified in section 3.1.7.

3. **Dip proofing inverter (DPI) integrity testing:**

DPIs and any other equipment must be tested according to the OEM requirements.

Document all results.

Report to be submitted to the System Operator one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.
### D-4.9 Unit Load and De-loading Rate Capability Grid Code Requirements

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Grid Code Reference</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intermediate Load Capability</td>
<td></td>
</tr>
</tbody>
</table>

**APPLICABILITY**

*Prototype study:* All new Power Stations coming on line or Power Stations where major refurbishment or upgrade of the Unit have taken place.

*Routine test:* All Units to be monitored continuously, additional tests may be requested by the System Operator

**PURPOSE**

Prove Unit can meet the minimum requirements of the Grid Code

**PROCEDURE**

A section of the Unit is to be tripped that will cause a 15% of MCR reduction of the output of the Unit. Should nothing be found to induce this reduction a sudden reduction of the Unit output shall be done manually. The plant is to be monitored and recorded to ensure the plant continues to operate in a stable and controlled mode after the reduction.

**ACCEPTANCE CRITERIA**
The Unit shall be in a stable and controlled mode after the trip or reduction in the Unit output.
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1 Introduction

(1) The Metering Code specifies Transmission and Distribution tariff and energy trading Metering requirements and clarifies responsibilities in terms of Metering Installations.

(2) The nationally adopted Metering standards e.g. SANS 474:2008, NRS 057:2011, IEC 62056, shall be used as the Metering requirements for this Code. This Code supplements some sections of the nationally adopted standards where these standards are inadequate.

(3) All sections written in this Code shall take precedence over the nationally adopted metering standards where disagreements and/or inadequacies exist.

2 Application of the Metering Code

(1) This Code shall apply to all Participants in respect of any Metering Point and applicable to:

a. Main Metering Installations and check Metering Installations used for the measurement of Active Power/Energy and Reactive Power/Energy

b. The design of the Metering Installation

c. The collection of Metering Data

d. The provision, installation and maintenance of Metering Apparatus

e. The accuracy of Apparatus used in the process of Metering

f. Testing procedures for Metering Installations

g. Storage requirements for Metering Data

h. Competencies and standards of performance of Participants
3 General Provisions

(1) The Metering Point shall be located at the point agreed upon between the Participants unless otherwise specified in this Code.

(2) Participants shall provide TransCos and/or DisCos (where applicable) with all Information reasonably required to enable optimal performance of their Metering duties.

4 Responsibility for Metering Installations

(1) The relevant TransCo or DisCo shall ensure that all points identified as Metering Points in accordance with Sections 2 and 3 above, have appropriate Metering Installations.

(2) The relevant TransCo or DisCo shall ensure that commissioning, maintenance, auditing and testing of Metering Installations are done in accordance with the nationally adopted standards.

(3) Where a TransCo or DisCo owns the Substation or the cable/line at the Metering Point, the respective TransCo or DisCo shall be responsible for providing the Metering Installation in accordance with this Code.

(4) Where the Metering Installation is between TransCos, the TransCos are to agree which TransCo is responsible for providing the Metering Installation.

(5) Where Metering Installations are between Customers (Large or Small) and TransCos or DisCos (where applicable), the Metering Installation should preferably be installed at the Point of Supply which defines the commercial boundary between the TransCo or DisCo and the Customer. Where this is not possible, the Metering Point shall be located at the point agreed between the relevant TransCo or DisCo and the Customer.

(6) Where a Metering Installation is between a TransCo or DisCo and a Generator or Embedded Generator (EG) (where applicable), the TransCo or DisCo shall be responsible for the Metering Installation whose location shall be agreed upon between the relevant Participants. If a Generator or EG would like to install an
additional Metering Installation, this is allowed. If the additional Metering Installation is at the same location as the above Metering Installation, the DisCo or TransCo shall allow access to the relevant location to allow for the installation of the additional Metering Installation. The cost of the additional Metering Installation shall be for the Participant installing the additional Metering Installation.

(7) TransCos shall be responsible for managing and collecting Metering Information on their respective TSs i.e. TransCos are the Transmission Metering Administrators (TMAs) for their respective TSs.

(8) DisCos shall be responsible for managing and collecting Metering Information on their respective DSs i.e. DisCos are the Distribution Metering Administrators (TMAs) for their respective DSs.

(9) Upon request from a Customer, Generator and/or EG, the relevant TMA or DMA shall provide applicable Information to the relevant Participant regarding Metering Installations, Metering Information and the TMA or DMA Metering database.

(10) A central co-ordinated database of all Metering Installations on the IPS shall be kept by the SO. It is the sole responsibility of the SO to ensure that this central co-ordinated database is kept up to date. The SO shall formulate the appropriate processes to ensure this occurs detailing timing of data collection from the TMAs and/or DMAs, procedures for this and general formatting as well as input fields of the database.

(11) The SO shall submit to an audit by the Authority when reasonably requested. The SO shall allow access by the Authority or an officially appointed subcontractor appointed by the Authority to the central database for the audit.

(12) TMAs and/or DMAs shall submit to an audit by the SO and/or the Authority when reasonably requested. TMAs and/or DMAs shall allow access to all applicable Information for the audit to the SO, the Authority or an officially appointed subcontractor appointed by the SO or the Authority.
5 **Metering installation requirements**

(1) The following requirements shall apply to all *Metering Installations*:

a. The type of *Metering Installation* at each *Metering Point* shall comply with the nationally adopted standard for *Metering* specifications as modified by this *Code* e.g. NRS 057.

b. Each *Metering Point* on the TS shall be installed with main *Metering*. There shall be at least one dedicated *Metering Current Transformer (CT)* and Voltage Transformer (*VT*) core. All *CTs* installed after the implementation of the *Grid Code* shall have separate main and check *CT* cores.

c. There shall be check metering installed at a *Point of Connection (PoC)* when agreed upon between *Participants*.

d. The accuracy of *Metering* and recorders shall be in accordance with the minimum requirements of the nationally adopted standard if applicable e.g. NRS 057.

e. Commissioning of the *Metering Installation* and *Metering Data* supporting systems shall take place in accordance with the requirements of the nationally adopted standard if applicable e.g. NRS 057.

f. Both active and reactive power/energy for *Participants* above the *Metering Threshold* shall be measurable without compromising any requirements of this *Code*.

g. Full four quadrant *Metering Installations* shall be installed for *Participants* when active and reactive energy flows in both directions.

h. Two quadrant *Metering Installations* shall be installed for *Participants* where active energy flows in both directions.

i. A *Metering Installation* above the *Metering Threshold* shall be configured to record and store *Metering Data* in half-hourly integration periods.
j. A Metering Installation above the Metering Threshold shall be able to store Data in memory for at least 40 days. Data stored in a Metering Installation shall be remotely and locally retrievable.

(2) The relevant TransCo or DisCo above the Metering Threshold shall connect a telecommunications medium to Metering Installations that will allow for remote downloading of Metering Data.

(3) The relevant TransCo or DisCo above the Metering Threshold shall remotely interrogate a Metering Installation daily or as mutually agreed upon between the affected Participants for appropriate storage and backup at a location other than the location of the Metering Installation.

(4) Metering Installations shall be visible and accessible, but the access to such shall be authorised by the relevant TransCo or DisCo unless the Metering Installation belongs to the Participant seeking access whereupon the TransCo or DisCo shall allow access upon request.

(5) TransCos and DisCos shall provide historical Metering Data for Customers, Generators and EGs on a secure server upon request.

(6) TransCos and DisCos shall provide, when required by Customers, Generators or EGs, real-time Metering impulses. The Customers, Generators or EGs shall bear the installation costs in such an event.

(7) The Metering Data retrieval process shall be a secure process whereby Metering Installations are directly interrogated to retrieve billing information from their systems. The protocols used to interrogate the Metering Installations shall be approved by the Authority/NSA or an agency acting on their behalf.

(8) In the event of a Metering Installation being used for purposes other than Metering Data, such use shall not in any way obstruct Metering Data collection and accuracy requirements.

(9) TransCos and DisCos shall communicate the secondary use of all Metering Installations to all Participants who may be affected by the secondary use of the Metering Installation.
(10) No secondary user shall interfere with VT/CT circuitry.

(11) Where own Metering staff or Metering Service Providers (as defined in the nationally adopted standard e.g. NRS 057) are contracted for any work related to Metering, the relevant TransCo or DisCo (where applicable) remains fully accountable to ensure compliance with the requirements of the Metering Code. The TransCo or DisCo shall thus only appoint own Metering staff or Metering Service Providers that have the necessary skills and authorisation to install Metering Apparatus. The skills requirements as specified in the nationally adopted standard shall be adhered to (NRS 057).

(12) All Primary and Secondary Apparatus shall be calibrated accordingly before installation as specified in the nationally adopted standard e.g. NRS 057.

6 Metering Apparatus maintenance

(1) All Participants (TransCos, DisCos, Generators, EGs, Customers) shall appoint own Metering staff or Metering Service Providers that have the necessary skills and authorisation to maintain Metering Apparatus. The skills requirements as specified in the nationally adopted standard shall be adhered to e.g. NRS057.

(2) Metering Installations shall be maintained according to the requirements and frequency in the nationally adopted standard e.g. NRS 057.

(3) For prepayment Metering Installations, the inspection procedure shall be followed as stated in the nationally adopted standard e.g. NRS057.

7 Metering Apparatus access

(1) Metering Apparatus owned by a TransCo or DisCo or a Metering Service Provider but installed on a Customer’s, Generator’s or EG’s premises shall remain the property of the TransCo, DisCo or Metering Service Provider.

(2) Customers, EGs or Generators shall not tamper or permit tampering with Metering Apparatus owned by themselves, TransCos, DisCos or any Metering Service Provider.
(3) Except with written consent by the owner, access by Customers, EGs, Generators or representatives of these Participants to Metering Installations, Metering circuits and Metering Data shall be restricted to ensure that the integrity of the Metering Installation including Metering device, Metering installation and Meter Data are not at risk.

(4) Customers, EGs, Generators or representatives of these Participants shall not have direct access to Metering Installations owned by TransCos or DisCos to obtain any Metering Information unless in the company of the relevant TransCo or DisCo and vice versa. Direct access includes access gained by downloading the Metering Information from the Metering Installation directly through the digital communication interface, or remotely through any communication media, or any other means other than visual access. Requests from Customers, EGs and Generators to read their own Metering Installations shall not be unreasonably refused.

(5) Except with written consent by the owner of a Metering Installation, any Customers, EGs, Generators or representatives of these Participants shall not install any Metering Installation or other Apparatus integrated into a TransCo’s or DisCo’s CT and VT Metering circuits, test blocks, terminals, or any portion forming part of the electrical Metering installation or vice versa.

(6) Customers, EGs, Generators or representatives of these Participants shall provide reasonable access to the Metering Apparatus owned and operated by the TransCo or DisCo, Metering Service Provider but installed on the Customer’s, EG’s or Generator’s premises provided an official identification is produced on request and vice versa.

(7) Where the Metering Installation is situated in a restricted area as defined in the appropriate legislation, procedure(s) as stated in the nationally adopted standard (NRS047), applicable legislation and/or as agreed between the Participants shall be followed to gain access to the Apparatus.

(8) Any changes that may affect a Participant’s authorised and safe access to the Metering Apparatus shall be reported as soon as it is brought to either Participant’s attention and rectified in the appropriate agreed upon timeframe.
8 **Metering Data retrieval**

(1) *TransCos* and *DisCos* shall ensure that the necessary Data retrieval Apparatus and processes are in place to achieve the Meter read frequency or regularity as required in the nationally adopted standard.

(2) The *Metering Data* retrieval process for Automated Meter Reading (AMR) typically on Large Customers, Generators and/or EGs shall be a secure process whereby *Metering Installations* are directly interrogated to retrieve billing Information from their memories. The retrieval process shall comply with the requirements in the nationally adopted standard e.g. NRS 071.

(3) Pre-payment *Metering Installations* are excluded from the requirements of this section.

9 **Data validation and verification**

9.1 **Data validation**

(1) *TransCos* and *DisCos* shall carry out Data validation in accordance with the nationally adopted standard e.g. NRS 057.

(2) Above the *Metering Threshold*, in the event of:

   a. electronic access to the *Metering Installation* not being possible.

   b. an emergency bypass or other scheme having no *Metering* system.

   c. *Metering Data* not being available;
   the *TransCo* or *DisCo* may resort to any of the following:


   b. Estimation or substitution subject to mutual agreement between the affected *Participants*. 
c. Profiling (based on among other parameters: geographical location, voltage level, sector specific customers).

d. Reading of the Metering Installation at scheduled intervals.

(3) In the event of an estimation having to be made, above the Metering Threshold the following shall apply:

a. The TransCo or DisCo shall produce a monthly report for all estimations made and shall submit this to the Authority upon request.

b. No estimation shall be made on three or more consecutive measurement periods, and if such estimation has to be made, the TransCo or DisCo shall ensure that the Metering Installations are downloaded for the billing cycle.

(4) Above the Metering Threshold, no more than three measurement periods may be estimated per Metering Point per Month. If such estimation has to be made, the relevant TransCo or DisCo shall ensure that the Metering Installations are downloaded for the billing cycle in lieu of the estimated Data.

9.2 Meter verification

(1) Above the Metering Threshold, in addition to the nationally adopted standard verification requirements e.g. NRS057, TransCos and DisCos shall compare Meter readings (advances) with their Metering Database at least once a year.

10 Metering Database

(1) As the relevant TMAs and DMAs, TransCos and DisCos respectively shall create, maintain and administer a Metering Database containing the following information:

a. Name and unique identifier of each Metering Installation

b. The date on which the Metering Installation was commissioned

c. The connecting Participants at the Metering Installation
d. Maintenance history for each Metering Installation

e. Telephone numbers used to retrieve Information from the Metering Installation

f. Type and form of the Metering Installation e.g. manufacturer, model

g. Fault history of a Metering Installation

h. Commissioning documents for Metering Installations

i. Calibration certificates for all Metering Installations

j. Information relating to raw and official values as indicated in the nationally adopted standard e.g. NRS 057-4

(2) TransCos and DisCos shall retain Metering Information for at least five years for audit trail purposes.

11 Testing of Metering Installations

(1) Any Participant may (upon request) test its Metering Installation by an independent accredited agent, in co-operation with the TransCo or DisCo concerned. The costs of such tests shall be for the account of the TransCo or DisCo concerned unless the Metering Apparatus is found to be within specification, in which event the cost shall be borne by the requesting Participant.

12 Metering Database inconsistencies

(1) In the event of testing revealing that Data in the Metering database is inaccurate, the TransCo or DisCo shall inform all affected Participants and corrections shall be made to the official Metering Data and associated billing by mutual agreement between Participants.
13 **Access to Metering Data**

(1) Applicable official *Metering Data* shall be made available by *TransCos* and *DisCos* to all authorised *Participants* in a format agreed upon between *Participants*.

(2) *TransCos* and *DisCos* shall publish all formats in which it can provide *Data* to *Participants*. All new formats shall be negotiated between *TransCos* and *DisCos* and the affected *Participants*.

(3) Non-standard *Data* provision methods shall be provided by *TransCos* and *DisCos* at the expense of the requesting *Participant* as mutually agreed upon between *Participants*.

(4) *TransCos* and *DisCos* shall administer access to *Metering Data* from their own *Metering* database in line with the nationally adopted standard e.g. NRS 057-4.

(5) The SO shall administer access to the central database in a similar manner to the nationally adopted standard e.g. NRS 057-4.

(6) All security requirements for *Metering Data* shall be as specified in the nationally adopted standard e.g. NRS 057.

14 **Confidentiality of Metering Data**

(1) *Metering Data* for use in energy trading and/or billing is confidential *Information* and shall be treated in accordance with the *Information Exchange Code*.

15 **Customer queries on Metering integrity and Metering Data**

(1) Where *Customers*, *Generators* or *EGs* indicate they have a query or complaint related to *Metering*, the relevant *TransCo* or *DisCo* shall comply with the applicable requirements of the nationally adopted standard (NRS 047).

(2) *Any Customers*, *Generators* or *EGs* may request the *TransCo* or *DisCo* or *Metering Service Provider*, to test a *Metering Installation*. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of
the TransCo or DisCo unless the Metering Installation is found to be within specification, in which event the cost shall be borne by the requesting Participant.

(3) A Customer, Generator or EG may request an independent audit of Metering Installations done by an agent or Metering Service Provider. The appointed agent or Metering Service Provider shall be mutually agreed upon between the two Participants. The requesting Participant shall be responsible for any costs of the audit unless the Metering Installations are proved to be outside the defined standards.

(4) If errors are found with the Metering after testing or auditing, the Customer’s, Generator’s or EG’s account will be adjusted according to the rectified Data.

(5) An audit result shall be submitted to the TransCos and/or DisCos and they shall respond to the Customer, Generator or EG within 30 calendar days on any account or Metering adjustments proposed in the audit report.

(6) Customers, Generators or EGs shall have the right to request an audit of the settlement process related to their account and the right to choose an independent agent qualified to perform the audit.

(7) Should no agreement be reached on account or Metering disputes between the Customers, Generators or EGs and the TransCos or DisCos, the dispute resolution procedure shall be followed as stipulated by in the Governance Code.
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Information Exchange Code

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Version 1.0

January 2012

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1 **Introduction**

(1) The *Information Exchange Code* defines the reciprocal obligations of *Participants* with regard to the provision of *Information* for the implementation of the *Grid Code*. The *Information* requirements, as defined for all *Participants*, are necessary to ensure non-discriminatory access to the *Transmission System (TS)* and *Distribution System (DS)* and the safe, reliable provision of *Generation*, *Transmission* and *Distribution* services.

(2) The *Information* requirements are divided into:

   a. Planning *Information*

   b. Operational *Information*

   c. Post-dispatch *Information*.

(3) *Information* criteria specified in the *Information Exchange Code* are supplementary to the other codes within the *Grid Code*. In the event of inconsistencies between other *Codes* and the *Information Exchange Code* with respect to *Information* exchange, the requirements of the *Information Exchange Code* shall prevail.

(4) The appendices relevant to this *Code* are in a separate document and should be referred to as required.

2 **Information Exchange interface**

(1) The *Participants* shall identify the following for each type of *Information* exchange:

   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, contact details of, and the *Participants* represented by persons requesting the *Information*.
c. The purpose for which the *Information* is required.

d. The *Participants* shall agree on appropriate procedures for the transfer of *Information*.

(2) With reference to the *Distribution System (DS)*, *Participants* with installed capacity of more than the *Metering Threshold* shall exchange *Information*, prior to commissioning, of new or altered *Apparatus* connected at the *Point of Connection* or changes to the operational regimes that could have an adverse effect on the *DS* to enable proper modifications to any affected *Participants* networks and related systems.

### 3 System planning *Information*

(1) *Large Customers, Embedded Generators (EGs)* and *GenCos* shall provide such *Information* as *TransCos* and *DisCos* (where appropriate) reasonably request on a regular basis for the purposes of planning and developing the *TS* and *DS*. *Large Customers, EGs* and *GenCos* shall submit the *Information* to the *TransCos* and *DisCos* without unreasonable delay. Such *Information* may be required so that *TransCos* and *DisCos* can plan and develop *TS* and *DS* systems accordingly, monitor current and future power system adequacy and performance as well as fulfil their statutory or regulatory obligations.

(2) *Small Customers*, selected *Large Customers* and *EGs* shall provide such *Information* as *DisCos* reasonably request on a regular basis without unreasonable delay for the purposes of planning and developing the *DS* and as required to fulfil their statutory or regulatory obligations.

(3) *TransCos* and *DisCos* (where applicable) shall provide the above *Information* where appropriate to the *TSO* for purposes of system wide and coordinated modelling and studying of the behaviour of the *IPS*.

(4) *Participants* shall submit to the *TransCos and DisCos* the *Information* listed in Appendix 2 (for *DisCos or Customers*) or Appendix 3 and Appendix 9 (for *GenCos*). *TransCos* and *DisCos* may request additional *Information* when reasonably required.
(5) *TransCos* shall provide *GenCos* with *Information* about *Apparatus* and systems installed in HV yards as defined in Appendix 10.

(6) *DisCos* shall provide *EGs (EGs)* with *Information* about *Apparatus* and systems installed in *LV, MV and HV* yards as defined in Appendix 10.

(7) *TransCos* and *DisCos* shall keep an updated technical database of their *TSs* and *DSs* for purposes of modelling and studying the behaviour of their *TSs* and *DSs* respectively.

(8) The *TSO* shall keep an updated technical database of the *IPS* for purposes of modelling and studying the behaviour of the *IPS*. This database shall include appropriate data for surrounding international networks where interactions will have an effect on the *IPS*.

(9) As described in the *Network Code*, *TransCos* shall provide *Large Customers, GenCos* and *DisCos*, upon any reasonable request, with any relevant *Information* that they require to properly plan and design their own networks/installations or to comply with their obligations in terms of the *Grid Code*.

(10) As described in the *Network Code*, *DisCos* shall provide *Customers* and *EGs*, upon any reasonable request, with any relevant *Information* that they require to properly plan and design their own networks/installations or to comply with their obligations in terms of the *Grid Code*.

(11) *Customers, GenCos* and *EGs* shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *TransCos* and/or *DisCos* with *Information* relating to the data given in Table 1.

<table>
<thead>
<tr>
<th>Commissioning</th>
<th>Projected or target commissioning test date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating</td>
<td>Target operational or on-line date</td>
</tr>
<tr>
<td>Reliability of connection requested</td>
<td>Number of connecting circuits, e.g. one or two feeders, or firm/non-firm supply required (subject to Network Code and Tariff Code requirements)</td>
</tr>
<tr>
<td>-----------------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Location map</td>
<td>Upgrades: Name of existing PoC 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, co-ordinates of the PoC to be specified</td>
</tr>
<tr>
<td>Site plan</td>
<td>Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed PoC, and where applicable, the Transmission/Distribution line route from the facility boundary to the PoC, clearly marked</td>
</tr>
<tr>
<td>Electrical single-line diagram</td>
<td>Provide an electrical Single Line Diagram (SLD) of the Customer intake substation</td>
</tr>
</tbody>
</table>

(12) TransCos and DisCos may estimate any system planning Information not provided by a GenCo, DisCo, EG or Customer. TransCos and DisCos shall take all reasonable steps to reach agreement with above Participants on estimated Data items. TransCos and DisCos shall indicate to the relevant above Participant any Data items that have been estimated. The obligation to ensure the correctness of Data remains with the Information owner providing the Information.

(13) GenCos and EGs shall submit weekly to the relevant TransCos and/or DisCos as well as the System Operator (SO) (where applicable) all the maintenance planning Information detailed in Appendix 4 with regard to each Unit at each Power Station (PS).

(14) TransCos and DisCos shall provide the approved monthly rolling maintenance schedule (approved by the SO) to Customers, GenCos and EGs
where appropriate for all planned work in Substations for a period of one year in advance.

(15) As required by the EAPP Interconnection Code, it is the TSO’s responsibility to provide the relevant Information to EAPP Sub-Committees (EAPP Sub-Committee on Planning and/or EAPP Sub-Committee on Operations). Relevant Information includes the Information required for modelling and analysis of the steady-state and dynamic behaviour of the EAPP Interconnected Transmission System. More specifically, this Data includes:

a. Basic Data: Electrical characteristics and ratings of Transmission Apparatus (Substations, Generating Units, AC Transmission lines, HVDC Transmission lines, transformers, reactive compensation and interchange schedules) for each year up to ten (10) years ahead.

b. Study Data: Demand Data including the distribution of demand across individual TS nodes, generation patterns, evaluation of Transmission capacity, interchanges with EAPP and non-EAPP members, thermal ratings of Transmission Apparatus, timing of new Apparatus and outage schedules and a list of appropriate contingencies.

4 Operational Information

4.1 Pre-commissioning studies

(1) Customers, Generators and EGs shall meet all system planning Information requirements before the commissioning test date (this includes confirming any estimated values assumed for planning purposes or, where practical, replacing them with validated actual values and with updated estimates for the future.)

(2) The SO in collaboration with the relevant TransCo or DisCo shall perform pre-commissioning studies prior to sanctioning the final connection of new or modified Apparatus to the TS or DS (including Customers, Generators and EGs), using supplied Data in accordance with section 3 of this Code, to verify that all control systems and Apparatus functions are correctly tuned and planning criteria have been satisfied.
(3) The SO in collaboration with the relevant TransCo or DisCo may request adjustments from the asset owner 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 duration of the operational life of the Apparatus. Information shall be made available within a reasonable time on request from the SO and relevant Participants upon notification of such a request.

4.2 Commissioning and notification

(1) The relevant Participants shall ensure that exciter, turbine governor, FACTS and HVDC control system settings are implemented and are as finally recorded by the SO prior to commissioning.

(2) Participants shall give the SO notice, as defined in the System Operations Code, of the time at which the commissioning tests will be carried out. The SO and the Participant shall agree on the timely provision of operational Data items as per Appendix 5.

(3) Records of commissioning shall be maintained for reference by the asset owner for the operational life of the Apparatus and shall be made available, within a reasonable time, to the SO upon notification of such a request.

(4) The asset owner shall communicate changes made during an outage to commissioned Apparatus to the SO and the relevant TransCo or DisCo, before the Apparatus is returned to service. The TransCo or DisCo shall keep commissioning records of operational Data as per Appendix 5 for the operational life of the Apparatus connected to the TS or DS.

4.3 General Information Data acquisition Information requirements

(1) Measurements and indications to be supplied by TransCos, GenCos, DisCos, EGs and Large Customers where appropriate to the SO shall include the formats 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 this and restore or correct the signals and/or indications as soon as is reasonable as agreed with the SO.
(2) The SO shall notify a Participant (if applicable), where the SO, acting reasonably and in consultation with the Participant, determines that additional measurements and/or indications in relation to a Participant’s Apparatus are needed to meet a TS requirement. The costs related to the Participant’s modifications for the additional measurements and/or indications shall be for the account of the providing Participant. On receipt of such a notification from the SO the Participant shall promptly ensure that such measurements and/or indications are made available at the Apparatus’ communications Gateway Apparatus.

(3) The Data formats to be used and the fields of Information to be supplied to the SO by various Participants are defined in Appendix 5.

(4) TransCos and DisCos shall provide periodic feedback to GenCos, EGs and Customers regarding the status of Apparatus and systems installed in Substations (where appropriate) where GenCos, EGs and Customers are connected to the relevant TransCo’s TS or DisCo’s DS. This feedback shall include results from tests, condition monitoring, inspections, audits, failure trends and calibration. The frequency of the feedback shall be determined in agreement between the Participants, but will not exceed one year. These status reports will also include contingency plans where applicable.

(5) The SO needs to inform Customers where out-of-step relays are installed and how the relays are expected to operate. Furthermore, the characteristics of the resultant islanded networks shall be provided by the SO, based on the most probable local network configuration at such a time.

(6) The cost of installation of Data Terminal Equipment (DTE) will be paid for by the relevant Participant.

(7) The Participant shall decide on the location of the DTE.

(8) The Participant will be responsible for the maintenance of communications links between Generating Unit Gateways and the DTE.

(9) The SO shall be responsible for the maintenance, upkeep and communication charges of the DTE.
4.4 **Unit scheduling**

(1) The SO shall create the *Data* defined in Appendix F for unit scheduling.

### 4.4.1 Schedules

(1) The SO shall define the next day’s twenty-four (24) hour day-ahead energy schedule based on the principles defined in the *System Operations Code* and this shall be given to all relevant *Participants* before 15:00 on the day before dispatch.

(2) The SO shall define the daily twenty-four (24) hours day-ahead *Ancillary Service* schedule and this shall be given to all relevant *Participants* before 15:00 on the day before dispatch.

(3) All *Information Exchange* requirements for *Ancillary Services* that are contracted annually shall be included in the relevant contracts between *Participants*.

### 4.4.2 File transfers

(1) The format of the file used for *Data* transfer through file transfers shall be negotiated with the SO. The *Data* shall be made available in a common, electronically protected directory. All file transfer *Data* shall be fetched by the SO. File transfer requirements are briefly summarised in Table 2.

**Table 2 File transfer requirements**

<table>
<thead>
<tr>
<th>File</th>
<th>Description</th>
<th>Trigger Event</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dispatch schedule</td>
<td>The combined 24-hour day-ahead energy and ancillary services schedules.</td>
<td>Generation dispatch schedule</td>
<td>Daily</td>
</tr>
</tbody>
</table>
4.5 Participants inter control centre communications

(1) Applicable Customers, Generators, EGs, DisCos and TransCos shall ensure that they provide the SO with network Information that is considered reasonable for the security and integrity of the IPS on request.

(2) The SO shall communicate network Information as requested to Customers, Generators, EGs, DisCos and TransCos, as required for safe and reliable operation of the IPS.

(3) The Information exchanged between Participants shall be electronic and/or paper-based, and within the time frame agreed upon between the Participants.

(4) The Participants shall optimise redundant communications where required for the safe operation and control of the IPS.

4.6 Communication facilities requirements

(1) The minimum communication facilities for voice and Data that are to be installed and maintained between the SO and TransCos, Large Customers, GenCos and DisCos shall comply with the applicable IEC standards for SCADA and communications Apparatus.

(2) The communication standards shall be set and documented by the SO, acting reasonably, in advance of design. Any changes to communication facility standards impacting on GenCos, EGs, Customers and/or DisCos Apparatus shall be designed in consultation with GenCos, EGs, Customers and/or DisCos and shall be informed by a reasonable business motivation.

4.6.1 Telecontrol

(1) The Information exchange between Participant’s Apparatus shall support Data acquisition to and from a Power Station’s Gateway. The SO shall be able to monitor the state of the IPS via telemetry from the Gateway connected to the Participant’s Power Station.
(2) 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.

(3) Participants shall interface via the standard digital interfaces, as specified by the SO. The provision and maintenance of the wiring and signalling from the Participant's Apparatus to the interface cable shall be the responsibility of the Participant.

(4) Participants shall comply with such telecontrol requirements as may be applicable to the National Grid Control Centre (NGCC) and, as reasonably required, to the emergency control centre of the SO. Any changes to telecontrol requirements impacting on Participant Apparatus shall be designed in consultation with Participants and shall be informed by a reasonable business motivation.

4.6.2 Telephone/facsimile

(1) Each GenCo and EG (where applicable) shall be responsible for the provision and maintenance of no fewer than one telephone and one facsimile unit on separate lines that shall be reserved for operational purposes only, and shall be continuously attended to and answered without undue delay.

(2) 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. 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 Authority.

4.6.3 Electronic mail

(1) Participants shall provide the SO with the electronic mailing address of the contact person as defined in this Information Exchange Code and vice versa. The provider of this service shall be selected to meet the real-time operational requirements of the SO.

4.7 SCADA and communication infrastructure at Points of Connection

4.7.1 Access and security
(1) The SO shall agree with the relevant Participants the procedures governing security and access to the Participants’ SCADA, computer and communications Apparatus. The procedures shall allow for adequate access to the Apparatus and Information by the SO or its nominated representative for purposes of maintenance, repair, testing and the taking of readings/measurements.

(2) 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 Participants, and shall disclose that person’s name and contact details to the Authority. A Participant may, at its sole discretion, designate more than one person to perform these duties.

4.7.2 Time standards

(1) All Information exchange shall be GPS satellite time signal referenced. The SO shall ensure broadcasting of the standard time to relevant telecommunications devices in order to maintain time coherence across the IPS.

4.7.3 Integrity of installation

(1) Where electrical Apparatus does not belong to a TransCo or DisCo, the TransCo or DisCo shall enter into an agreement with a Participant for the provision of reliable and secure facilities for the housing and operation of TransCo and DisCo Apparatus. This includes access to, at no charge to the relevant TransCo or DisCo, an uninterruptible power supply with an eight-hour standby capacity.

4.8 Data storage and archiving

(1) The obligation for Data storage and archiving shall lie with the Information Owner.

(2) The systems that store the Data and/or Information to be used by Participants shall be of their own choice and for their own cost.

(3) All the systems must be able to be audited by the Authority. 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 Participants.
4 The Information Owner shall store the Information in a manner that will allow for such Information to be retrieved on request and shall ensure that the contents remain unaltered from their original state. The Information shall be retained for a period of at least five (5) years (unless otherwise specified in the Grid Code) commencing from the date the Information was created.

5 Participants shall ensure reasonable security against unauthorised access, use and loss of Information (i.e. have a backup strategy) for the systems that contain the Information.

6 Participants shall store outage planning Information as defined in section 3 clause (13) and (14) electronically for at least five (5) years. Other system planning Information as defined in section 3 shall be retained for the life of the Apparatus concerned, whichever is the longer.

7 The SO shall archive operational Information, in a historical repository sized for three (3) years of Data. This Data shall include:

a. TS time-tagged status Information, change of state alarms, and event messages.

b. Hourly scheduling and energy accounting Information.

c. SO entered Data and actions.

8 An audit trail of all changes made to archived Data should be maintained. This audit trail shall identify every change 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.

5 Post-dispatch Information

5.1 Common IPS information

1 The SO shall provide all Participants with the following Information on a daily basis::
a. Hourly system total MW loading.

b. Hourly individual power station MW sent out.

c. Hourly system constraints and constrained generation.

d. Hourly international tie-line power flows.

e. Pre-determined system load flow Data.

5.1.1 Generation settlement

(1) The appropriate TradeCos (including NEP (Trader) as the GenCo of last resort i.e. balancing responsibility) shall settle generation with GenCos based on their bilateral agreements and on ex post Information from the SO or their appropriate Metering Apparatus.

(2) The above Participants shall make this Information available to the relevant Participants, within an agreed time period. Should this Information be classified as confidential, Participants shall treat it accordingly.

5.1.2 Ancillary Services settlement

(1) The SO has the sole responsibility for securing Ancillary Services and accordingly shall request all Data required for settlement of Ancillary Services from TransCos, DisCos, Generators, appropriate EGs and Customers. These Participants shall make this Information available, within an agreed time period to the SO. Should this Information be classified as confidential, Participants shall treat it accordingly.

5.1.3 Additional unit post dispatch Information

(1) The SO shall provide operational Information regarding Unit dispatch and overall dispatch performance as specified in Appendix 7.
5.2 File transfers

(1) The format of the files used for Data transfer shall be negotiated and defined by the supplier and receiver of the Information. The file transfer media shall be negotiated and defined by both Participants involved.

(2) Participants shall keep the agreed number of files for backup purposes so as to enable the recovery of Information in the case of communication failures.

(3) Typical file transfers between the SO and Generators are given in Table 3.

<table>
<thead>
<tr>
<th>File</th>
<th>Description</th>
<th>Trigger Event</th>
<th>Frequency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Energy dispatch instructions</td>
<td>Record of Energy Dispatch Instructions sent to Generators from the SCADA system including AGC</td>
<td>Ongoing file appended at the end of the hour</td>
<td>Daily</td>
</tr>
<tr>
<td>Ancillary Service Dispatch Instructions</td>
<td>Record of Ancillary Service Dispatch Instructions sent to Generators from the SCADA system including AGC</td>
<td>Ongoing file appended at end of hour</td>
<td>Daily</td>
</tr>
<tr>
<td>Power Pool Performance and settlement data</td>
<td>As required by relevant Power Pool Rules</td>
<td>Ongoing, file appended at end of hour</td>
<td>Daily</td>
</tr>
<tr>
<td>System near real-time Data</td>
<td>Historic near real-time system Data files on readings as required for post-dispatch</td>
<td>Communication Failure</td>
<td>To be agreed</td>
</tr>
<tr>
<td>Unit near real-time Data</td>
<td>Historic near real-time unit Data files on readings as required for post-dispatch</td>
<td>Communication Failure</td>
<td>To be agreed</td>
</tr>
</tbody>
</table>
5.3 Performance Data

5.3.1 Generator performance Data

(1) Generators shall provide the SO monthly with performance indicators in relation to each Unit at each Power Station in respect of availability, reliability, etc., as detailed in Appendix 8.

(2) Generators shall report significant events, such as catastrophic failures, to the Authority within one (1) week of occurrence of such event.

5.3.2 Distributor and Customer performance

(1) Where appropriate, EGs shall provide sufficient Information to DisCos to ensure that DisCo's performance indices (as defined in the Network Code) are satisfactory.

(2) The performance measurements of all DisCos and relevant Customers shall be supplied to the SO in accordance with the operating agreement requirements as defined in the Network Code.

(3) DisCos and TransCos shall report periodic testing of Under-Frequency Load Shedding (UFLS) relays in the format given in Table 4.

Table 4 Under Frequency Load Shedding (UFLS) reporting and testing format

<table>
<thead>
<tr>
<th>TransCo/DisCo Name:</th>
<th>Date:</th>
</tr>
</thead>
<tbody>
<tr>
<td>Substation Name:</td>
<td></td>
</tr>
<tr>
<td>Fed from which Transmission Substation (directly or indirectly):</td>
<td></td>
</tr>
<tr>
<td>Activating frequency</td>
<td>Timer setting</td>
</tr>
<tr>
<td>Required</td>
<td>As tested</td>
</tr>
<tr>
<td>Stage 1</td>
<td></td>
</tr>
<tr>
<td>Stage 3</td>
<td></td>
</tr>
<tr>
<td>Feeders selected (required)</td>
<td>Feeders selected (as tested)</td>
</tr>
</tbody>
</table>
5.3.3 **TransCo performance**

(1) TransCos shall make the TS performance indicators *Information* given in Table 5 available monthly to the SO, the Authority, DisCos, GenCos and relevant Customers.

<table>
<thead>
<tr>
<th>Table 5 TransCo performance information to be made available</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Indicator</strong></td>
</tr>
<tr>
<td>-------------------------------------------------</td>
</tr>
<tr>
<td>System minutes lost</td>
</tr>
<tr>
<td>No. of interruptions</td>
</tr>
<tr>
<td>No. of statutory voltage transgressions</td>
</tr>
<tr>
<td>Mandatory under-frequency load shedding</td>
</tr>
<tr>
<td>SAIDI</td>
</tr>
<tr>
<td>SAIFI</td>
</tr>
<tr>
<td>SAIRI</td>
</tr>
<tr>
<td>TS losses</td>
</tr>
</tbody>
</table>
(2) *TransCos* shall provide *DisCos* and *Customers* with all performance indicators at each *Point of Supply* in accordance with section 4.3 of the *Network Code*.

### 5.3.4 System operational performance *Information*

(1) The following *IPS* operational *Information* shall be published by the *SO* to all *Participants*:

a. Daily:

   i. The hourly actual demand of the previous day (MW)

   ii. Hourly *Primary Response* reserve amounts of the previous day (MW)

b. Monthly:

   i. Power (MW) generated

   ii. Power (MW) imported

   iii. Power (MW) exported

   iv. Power (MW) available for distribution/sale

   v. Overall *TS* losses.

   vi. Each *Power Station*’s availability

   vii. *Secondary Response* reserve hours deficit over total hours

   viii. Number of frequency excursions: $f > 51.0 \text{ Hz}$ or $f < 49.0 \text{ Hz}$

   ix. For each abnormal network condition the action taken by the *SO* to restore normal operations

   x. Network constraints (details to be defined by the *Authority*)

c. Annually:
i. Annual IPS peak (MW), date and hour

ii. Annual IPS minimum (MW), date and hour

(2) TransCos shall make available all Information collected via recorders installed at Substations, to the SO for analysis. The SO shall make this Information available to affected Participants on request.

6 Confidentiality of Information

(1) Information exchanged between Participants governed by this Code shall not be confidential, unless otherwise stated.

(2) Confidential Information shall not be transferred to a third Participant without the written consent of the Information Owner. Participants shall observe the proprietary rights of third Participants for the purposes of this Code. Access to confidential Information within the organisations of Participants shall be provided as reasonably required.

(3) Participants receiving Information shall use the Information only for the purpose for which it was supplied.

(4) The Information Owner may request the receiver of Information to enter into a Confidentiality Agreement before Information, established to be confidential, is provided. A sample Confidentiality Agreement is included in Appendix 1.

(5) Participants shall take all reasonable measures to control unauthorised access to confidential Information and to ensure secure Information exchange. Participants shall report any leak of Information that is governed by a Confidentiality Agreement as soon as practicable after they become aware of 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).
THE RWANDA GRID CODE

Information Exchange Code:

Appendices

6 of 7 Code Documents

Version 1.0

January 2012

Enquiries: RURA, Rwanda
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APPENDIX 1: Information confidentiality

SAMPLE 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, as strictly confidential.
2. The Recipient agrees to disclose the Information only to 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 computer disks 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/she becomes aware of 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).

Signed at ...................................................... on this the ........ day of ...................................................... by (full name) ......................................................in his/her capacity as ...................................................... on behalf of ......................................................, the Information Owner

......................................................
APPENDIX 2: Distributor and Customer data

Unless otherwise indicated, the following information shall be supplied to the TransCos (System Operator) prior to connection and then updated as and when changes occur.

(a) Demand and network data

<table>
<thead>
<tr>
<th>Connection capacity</th>
<th>Connection capacity required (MW)</th>
</tr>
</thead>
</table>
| Measured and forecast data (annually) | For each point of supply, the information required is as follows:  
A 10-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 (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, X, B, R0, X0, B0, continuous and probabilistic ratings)  
Contribution from Customer network to a three-phase short-circuit at point of connection  
Information pertaining to the network connecting shunt capacitors, harmonic filters, reactors, SVC's, etc., to the point of supply for the 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 for 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 switchbays 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. quality of supply)
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 System Operator 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 NRS048. The size limit for arc furnaces is subject to local conditions in respect of fault levels 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

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of windings</td>
<td></td>
</tr>
<tr>
<td>Vector group</td>
<td></td>
</tr>
<tr>
<td>Rated current of each winding</td>
<td>A</td>
</tr>
<tr>
<td>Transformer rating</td>
<td>MVA&lt;sub&gt;Trans&lt;/sub&gt;</td>
</tr>
<tr>
<td>Transformer tertiary rating</td>
<td>MVA</td>
</tr>
<tr>
<td>Transformer nominal LV voltage</td>
<td>kV</td>
</tr>
<tr>
<td>Transformer nominal tertiary voltage</td>
<td>kV</td>
</tr>
<tr>
<td>Transformer nominal HV voltage</td>
<td>kV</td>
</tr>
<tr>
<td>Tapped winding</td>
<td>HV/MV/LV/None (Delete what is not applicable)</td>
</tr>
<tr>
<td>Transformer ratio at all transformer taps</td>
<td></td>
</tr>
<tr>
<td>Transformer impedance (resistance R and reactance X) at all taps</td>
<td>R+jX</td>
</tr>
<tr>
<td>---</td>
<td>---</td>
</tr>
<tr>
<td>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</td>
<td>Z_{HVMV}, Z_{HLVLV}, &amp; Z_{MVLV}</td>
</tr>
<tr>
<td>Transformer zero sequence impedances at nominal tap</td>
<td></td>
</tr>
<tr>
<td>Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals open-circuit</td>
<td>Z_{HT0}</td>
</tr>
<tr>
<td>Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals short-circuited to the neutral</td>
<td>Z_{HL0}</td>
</tr>
<tr>
<td>Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals open-circuit</td>
<td>Z_{LT0}</td>
</tr>
<tr>
<td>Zero phase sequence impedance measured between the HV terminals (shorted) and the neutral terminal, with the LV terminals short-circuited to the neutral</td>
<td>Z_{LH0}</td>
</tr>
<tr>
<td>Zero phase sequence leakage impedance measured between the HV terminals (shorted) and the LV terminals (shorted), with the Delta winding closed</td>
<td>Z_{L0}</td>
</tr>
<tr>
<td>Earthing arrangement, including LV neutral earthing resistance and reactance core construction (number of limbs, shell or core type)</td>
<td></td>
</tr>
<tr>
<td>Open-circuit characteristic</td>
<td>Graph</td>
</tr>
</tbody>
</table>

Transformer test certificates, from which actual technical detail can be extracted as required, are to be supplied on reasonable 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 10 Mvar connected to or capable of being connected to a customer network, the customer shall inform the TransCo (or System Operator) and, if required, shall provide the TransCo (or System Operator) 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 *TransCo* (or System Operator) of his intention to extend or modify this equipment.

If any participant finds that a capacitor bank of 10 Mvar or less is likely to cause harmonic resonance problems on the TS, he shall inform the *TransCo* (or System Operator). The 10 Mvar minimum size limit shall thereafter be waived in respect of the affected network for information reporting purposes in respect of this code, and the *TransCo* (or System Operator) 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 10 Mvar or less no longer cause harmonic resonance problems on the TS, the *TransCo* (or System Operator) 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.

<table>
<thead>
<tr>
<th>Shunt capacitor or reactor rating</th>
<th>Rating (Mvar)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reactor/capacitor/harmonic filter</td>
<td>(delete what is not applicable)</td>
</tr>
<tr>
<td>Location (station name)</td>
<td></td>
</tr>
<tr>
<td>Voltage rating</td>
<td>KV</td>
</tr>
<tr>
<td>Resistance/reactance/susceptance of all components of the capacitor or reactor bank</td>
<td></td>
</tr>
<tr>
<td>Fixed or switched</td>
<td></td>
</tr>
<tr>
<td>If switched</td>
<td>Control details (manual, time, load, voltage, etc.)</td>
</tr>
<tr>
<td>If automatic control</td>
<td>Details of settings. If under FACTS device control (e.g. SVC), which device?</td>
</tr>
</tbody>
</table>

(d) Series capacitor or reactor data requirements

Series capacitors are installed in long transmission lines to increase load transfer capability.

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

<table>
<thead>
<tr>
<th>Location (specify substation bay where applicable)</th>
<th>(Delete what is not applicable)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage rating</td>
<td>KV</td>
</tr>
<tr>
<td>Impedance rating</td>
<td>Ohm or Mvar</td>
</tr>
<tr>
<td>Current rating (continuous and emergency, maximum times for emergency ratings)</td>
<td>Continuous: A Hours A Hours A Hours A</td>
</tr>
</tbody>
</table>

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 and HVDC data

**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:

- Voltage regulation following loss of a system component, generation, large load, or HVDC link disturbance
- Arc furnace voltage flicker mitigation
- Negative phase sequence voltage compensation
- SSR (sub-synchronous resonance) damping
- Machine transient stability enhancement
- System load transfer capability enhancement
- Load sharing control in interconnected, deregulated, networks

The most commonly used FACTS device is the SVC (static Var compensator). Other FACTS devices made possible by advances in power electronics and control systems include STATCON (static condenser), TCSC (thyristor controlled series capacitor), thyristor controlled tap changer, thyristor controlled phase shifter, BES (battery energy storage), and UPFC (unified power controller). The common factor is rapid control capability.
Because FACTS devices are purpose-designed for their specific applications, the following data is required:

<table>
<thead>
<tr>
<th>Name</th>
<th>Station, HV voltage, device number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type</td>
<td>(SVC, STATCON, TCSC, etc.)</td>
</tr>
<tr>
<td>Configuration: provide a single line diagram showing all HV components and their MVA/Mvar and voltage ratings, with all controlled components identified as such</td>
<td></td>
</tr>
<tr>
<td>Control system: provide a block diagram of the control system suitable for dynamics modelling</td>
<td></td>
</tr>
<tr>
<td>Primary control mode</td>
<td>Voltage control, arc furnace flicker mitigation, negative phase sequence voltage control, etc.</td>
</tr>
</tbody>
</table>

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 NRS048.

**HVDC**

Strictly speaking, 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 TransCo (or System Operator) shall co-operate 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 contravene the QOS parameters specified in NRS048, and where applicable shall specify what additional HV plant will be required to ensure compliance with NRS048.
(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**

<table>
<thead>
<tr>
<th>Units</th>
<th>Line description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Name (“from” busbar, “to” busbar, circuit number and, where applicable, line section number numbered from the “from” busbar end)</td>
<td>Line description</td>
</tr>
<tr>
<td>Line voltage (specify separately for dual voltage multicircuit lines)</td>
<td>KV</td>
</tr>
<tr>
<td>Single/double/multiple circuit</td>
<td>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</td>
</tr>
<tr>
<td>Phase sub-conductor type (per circuit)</td>
<td></td>
</tr>
<tr>
<td>Number of sub-conductors per phase conductor bundle</td>
<td></td>
</tr>
<tr>
<td>Sub-conductor spacing, if applicable (supply sketch showing phase conductor bundle geometry and attachment point)</td>
<td>Mm</td>
</tr>
<tr>
<td>Number of earth wires</td>
<td></td>
</tr>
</tbody>
</table>
### Earthwire description

<table>
<thead>
<tr>
<th>Line length</th>
<th>Km</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductor parameters ($R$, $X$, $B$, $R_0$, $X_0$, $B_0$)</td>
<td>Ohmic values or p.u. on 100MVA base (specify)</td>
</tr>
<tr>
<td>Conductor normal and emergency ratings</td>
<td>Ampere or 3-phase MVA at nominal voltage</td>
</tr>
</tbody>
</table>

### Cable data

<table>
<thead>
<tr>
<th>Cable description</th>
<th>Name (“from” busbar, “to” busbar, circuit number, and where applicable, line section number numbered from the “from” busbar end)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voltage rating</td>
<td>KV</td>
</tr>
<tr>
<td>Type (copper/aluminium)</td>
<td>(Delete what is not applicable)</td>
</tr>
<tr>
<td>Size</td>
<td>mm²</td>
</tr>
<tr>
<td>Impedance ($R$, $X$, $B$, $R_0$, $X_0$, $B_0$)</td>
<td>Ohms or p.u. on 100MVA base (specify)</td>
</tr>
<tr>
<td>Length</td>
<td>Km</td>
</tr>
<tr>
<td>Continuous and (where applicable) emergency current rating and time limit</td>
<td>Amp or MVA at nominal voltage (specify), hours maximum at emergency rating</td>
</tr>
</tbody>
</table>
APPENDIX 3: Generator planning data

Unless otherwise indicated, the following information shall be provided to the TRANSCO prior to connection and then updated as and when changes occur.

(a) Power station data

<table>
<thead>
<tr>
<th>Generator name</th>
<th>Power station name</th>
<th>Number of units</th>
<th>Primary fuel type/prime mover</th>
<th>Secondary fuel type</th>
<th>Capacity requirement</th>
<th>“Restart after station blackout” capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td>For example, gas, hydro, fossil or nuclear</td>
<td>For example, oil</td>
<td>Generation sent-out connection capacity required (MW)</td>
<td>Provide a document containing the following: Start-up time for the first unit (time from restart initiation to synchronise) and each of the following units assuming that restarting of units will be staggered</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>A document stating the number of units that can be black started at the same time, preparation time for the first unit black starting, restarting time for the first unit, and restarting time for the rest of the units</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>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</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>A document outlining all systems common to more than one unit that is likely to cause a MUT; discuss the measures taken to reduce the risk of MUT</td>
</tr>
</tbody>
</table>

(b) Unit data

<table>
<thead>
<tr>
<th>Unit number</th>
<th>Capacity</th>
<th>Unit capacity (MW)</th>
</tr>
</thead>
</table>

<p>| Units |
|------------------|----------------|-------------------|
| Maximum continuous generation capacity: | MW | |
| Maximum continuous sent out capacity | MW |
| Unit auxiliary active load | MW |
| Unit auxiliary reactive load | MVAr |
| EL1 | MW |</p>
<table>
<thead>
<tr>
<th>Description</th>
<th>Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capability chart showing full range of operating capability of the generator, including thermal and excitation limits</td>
<td>Diagram</td>
</tr>
<tr>
<td>Systems that are common and can cause a multiple unit trip</td>
<td>Description</td>
</tr>
<tr>
<td>Open-circuit magnetisation curves</td>
<td>Graph</td>
</tr>
<tr>
<td>Short-circuit characteristic</td>
<td>Graph</td>
</tr>
<tr>
<td>Zero power factor curve</td>
<td>Graph</td>
</tr>
<tr>
<td>V curves</td>
<td>Diagram</td>
</tr>
<tr>
<td>Documents</td>
<td>Description</td>
</tr>
<tr>
<td>---------------------------</td>
<td>-------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Protection settings</td>
<td>A document agreed and signed by the <strong>System Operator</strong> containing the following:</td>
</tr>
<tr>
<td>document</td>
<td>- A section defining the base values and per unit values to be used</td>
</tr>
<tr>
<td></td>
<td>- A single line diagram showing all the protection functions and sources of current and voltage signals</td>
</tr>
<tr>
<td></td>
<td>- Protection tripping diagram(s) showing all the protection functions and associated tripping logic and tripping functions</td>
</tr>
<tr>
<td></td>
<td>- A detailed description of setting calculation for each protection setting relevant to the TS connection, discussion on protection function stability calculations, and detailed dial settings on the protection relay in order to achieve the required setting</td>
</tr>
<tr>
<td></td>
<td>- A section containing a summary of all protection settings on a per unit basis</td>
</tr>
<tr>
<td></td>
<td>- A section containing a summary for each of the protection relay dial settings/programming details</td>
</tr>
<tr>
<td></td>
<td>- An annex containing plant information data (e.g. OEM data) on which the settings are based</td>
</tr>
<tr>
<td></td>
<td>- An annex containing OEM information sheets or documents describing how the protection relays function</td>
</tr>
<tr>
<td>Excitation settings</td>
<td>A document agreed and signed by the <strong>System Operator</strong> containing the following:</td>
</tr>
<tr>
<td>document</td>
<td>- A section defining the base values and per unit values to be used</td>
</tr>
<tr>
<td></td>
<td>- A single line diagram showing all the excitation system functions and all the related protection tripping functions</td>
</tr>
<tr>
<td></td>
<td>- An excitation system transfer function block diagram in accordance with IEEE or IEC standard models</td>
</tr>
<tr>
<td></td>
<td>- 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</td>
</tr>
<tr>
<td></td>
<td>- A section containing a summary of all settings on a per unit basis</td>
</tr>
<tr>
<td></td>
<td>- A section containing a summary for each of the excitation system dial settings/programming details.</td>
</tr>
<tr>
<td></td>
<td>- An annex containing plant information data (e.g. OEM data) on which the settings are based</td>
</tr>
<tr>
<td></td>
<td>- An annex containing OEM information sheets or documents</td>
</tr>
</tbody>
</table>
The document shall include models of the turbine, boiler, reactor, penstock and the relevant controls, which together can be used by the SO to simulate the dynamic performance of the unit, specifically load ramping and frequency support within the normal operating range of the unit. The generator may obtain guidance about the modelling requirements from IEEE documentation or any other standard agreed to by the SO.

The document, to be agreed and signed by the SO, will contain the following:
- The operating parameters on which the model is based, with the per unit and corresponding base values
- A governor (turbine controller) single-line diagram showing all the governor system functions
- A model for the dynamic response of the unit in block diagram form, in accordance with IEEE standard models or any other model standard agreed to by the SO
- A detailed list of gains, constants and parameters, with explanations of the derivations for each of the modelled functions of the governor system model
- Plant test data from which the model was derived

(c) Reserve capability

The generator shall provide the System Operator with the reserve capability of each unit at each power station. The reserve capability shall be indicated as per each reserve category: instantaneous reserve, regulating reserve, emergency reserve, ten (10) minute reserve and supplemental reserve.

(d) Unit parameters

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>$X_d$</td>
<td>% on rating</td>
</tr>
<tr>
<td>$X_{d,\text{sat}}$</td>
<td>% on rating</td>
</tr>
<tr>
<td>$X_{d,\text{unsat}}$</td>
<td>% on rating</td>
</tr>
</tbody>
</table>
### Sub-typographic 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

\[ R_a \]  
% on rating

### Stator leakage reactance

\[ X_L \]  
% on rating

### Poitier reactance

\[ X_P \]  
% on rating

### Generator time constants:

- Direct axis open-circuit transient
  \[ T_{do} \]  
sec
- Direct axis open-circuit sub-transient
  \[ T_{do}'' \]  
sec
- Quad axis open-circuit transient
  \[ T_{qo} \]  
sec
- Quad axis open-circuit sub-transient
  \[ T_{qo}'' \]  
sec
- Direct axis short-circuit transient
  \[ T_d \]  
sec
- Direct axis short-circuit sub-transient
  \[ T_d'' \]  
sec
- Quad axis short-circuit transient
  \[ T_q \]  
sec
- Quad axis short-circuit sub-transient
  \[ T_q'' \]  
sec

### Speed damping

\[ D \]

### Saturation ratio at 1 pu terminal voltage

\[ S(1.0) \]

### Saturation ratio at 1.2 pu terminal voltage

\[ S(1.2) \]

---

**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 System Operator) 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. The criteria for such dynamic instability shall be supplied by the System Operator. 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.
<table>
<thead>
<tr>
<th>Parameter</th>
<th>Symbol</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Excitation system type (AC or DC)</td>
<td>Text</td>
<td></td>
</tr>
<tr>
<td>Excitation feeding arrangement (solid or shunt)</td>
<td>Text</td>
<td></td>
</tr>
<tr>
<td>Excitation system filter time constant</td>
<td>Tr</td>
<td>Sec</td>
</tr>
<tr>
<td>Excitation system lead time constant</td>
<td>Tc</td>
<td>Sec</td>
</tr>
<tr>
<td>Excitation system lag time constant</td>
<td>Tb</td>
<td>Sec</td>
</tr>
<tr>
<td>Excitation system controller gain</td>
<td>Ka</td>
<td></td>
</tr>
<tr>
<td>Excitation system controller lag time constant</td>
<td>Ta</td>
<td>Sec</td>
</tr>
<tr>
<td>Excitation system maximum controller output</td>
<td>Vmax</td>
<td>p.u.</td>
</tr>
<tr>
<td>Excitation system minimum controller output</td>
<td>Vmin</td>
<td>p.u.</td>
</tr>
<tr>
<td>Excitation system regulation factor</td>
<td>Kc</td>
<td></td>
</tr>
<tr>
<td>Excitation system rate feedback gain</td>
<td>Kf</td>
<td></td>
</tr>
<tr>
<td>Excitation system rate feedback time constant</td>
<td>Tf</td>
<td>Sec</td>
</tr>
</tbody>
</table>
(f) 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.

(g) Pumped storage

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir capacity</td>
<td>MWh pumping</td>
</tr>
<tr>
<td>Max pumping capacity</td>
<td>MW</td>
</tr>
<tr>
<td>Min pumping capacity</td>
<td>MW</td>
</tr>
<tr>
<td>Efficiency (generating/pumping ratio)</td>
<td>%</td>
</tr>
</tbody>
</table>

(h) Unit step-up transformer

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Units</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of windings</td>
<td></td>
</tr>
<tr>
<td>Vector group</td>
<td></td>
</tr>
<tr>
<td>Rated current of each winding</td>
<td>Amps</td>
</tr>
<tr>
<td>Transformer rating</td>
<td>MVA_{Trans}</td>
</tr>
<tr>
<td>Transformer nominal LV voltage</td>
<td>KV</td>
</tr>
<tr>
<td>Transformer nominal HV voltage</td>
<td>KV</td>
</tr>
<tr>
<td>Tapped winding</td>
<td></td>
</tr>
<tr>
<td>Transformer ratio at all transformer taps</td>
<td>% on rating</td>
</tr>
<tr>
<td>Transformer impedance at all taps</td>
<td>MVA_{Trans}</td>
</tr>
<tr>
<td>(for three winding transformers the HV/LV1, HV/LV2 and LV1/LV2 impedances together with associated bases shall be provided)</td>
<td></td>
</tr>
<tr>
<td>Transformer zero sequence impedance at nominal tap</td>
<td>$Z_0$ Ohm</td>
</tr>
<tr>
<td>Earthing arrangement, including neutral earthing resistance and reactance</td>
<td></td>
</tr>
<tr>
<td>Core construction (number of limbs, shell or core type)</td>
<td></td>
</tr>
<tr>
<td>Open-circuit characteristic</td>
<td>Graph</td>
</tr>
</tbody>
</table>

(i) Unit forecast data
The generator shall provide the TRANSCO with expected maintenance requirements, in weeks per annum, for each unit at a power station.

(l) Mothballing of generating plant:

Mothballing of generating plant is the withdrawal of plant from commercial service for six months or longer, with the intention of returning it to commercial service at a later date. Mothballing can have a profound impact on the operation and integrity of the TS. Customers wishing to mothball generating plant shall supply the TRANSCO with the following information:

<table>
<thead>
<tr>
<th>Generator name</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power station name</td>
<td></td>
</tr>
<tr>
<td>Unit number</td>
<td></td>
</tr>
<tr>
<td>Date withdrawn</td>
<td>Date unit is to be withdrawn from commercial service</td>
</tr>
<tr>
<td>Return to commercial service</td>
<td>Envisaged return to service date (recommissioning tests completed and unit available for commercial service)</td>
</tr>
<tr>
<td>Auxiliary power requirements</td>
<td></td>
</tr>
</tbody>
</table>

(k) Return to service of mothballed generating plant:

Once the customer has decided to return mothballed generating plant to service, the TRANSCO requires the information specified for new connections.

(l) Decommissioning of generating plant:

Decommissioning of plant is the permanent withdrawal from service of generating plant. The TRANSCO requires the following with a one-year notice period:

<table>
<thead>
<tr>
<th>Generator name</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Power station name</td>
<td></td>
</tr>
<tr>
<td>Unit number</td>
<td></td>
</tr>
<tr>
<td>Date to be removed from commercial service</td>
<td></td>
</tr>
<tr>
<td>Auxiliary supplies required for dismantling and demolition</td>
<td>kVA, point at which supply is required, duration</td>
</tr>
</tbody>
</table>
APPENDIX 4: Generator maintenance plan

a) The 52-weeks-ahead maintenance plan per week per generator shall be supplied weekly to the System Operator.

Generator:

<table>
<thead>
<tr>
<th>DATE (week starting)</th>
<th>WEEK NUMBER:</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>n</td>
<td>n+1</td>
<td>...</td>
<td>n+51</td>
<td></td>
</tr>
</tbody>
</table>

**MAINTENANCE (MW)**

<table>
<thead>
<tr>
<th>WEEKEND OUTAGES</th>
<th>Power Station 1</th>
<th>Power Station 2</th>
<th>Power Station 3</th>
<th>Power Station n</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>TOTAL MAINTENANCE</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>FUTURE KNOWN UNPLANNED:</th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
</table>

For MAJOR CHANGES SINCE LAST WEEK:

Notes:

<table>
<thead>
<tr>
<th>FUTURE KNOWN UNPLANNED:</th>
<th>a)</th>
<th>b)</th>
</tr>
</thead>
</table>

b) The annual maintenance/outage plan per generator, looking five years ahead, shall be supplied to the System Operator.

The format shall be as per the 52-weeks-ahead outage plan per week per generator, but extending for five years.

c) A monthly variance report, explaining the differences between the above two reports, shall be supplied to the System Operator.
<table>
<thead>
<tr>
<th>Station and MW</th>
<th>Start Date</th>
<th>Outage Completion Date</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Outage Code</strong></td>
<td><strong>Cap</strong></td>
<td><strong>Official</strong></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX 5: Operational data

This appendix specifies the data format to be used by the SCADA system for the mapping of Gateway data into the SCADA database. The database has a definition for each bay in the HV yard. Each bay definition specifies a different bay type, e.g. transformers, units, feeders, etc., and is accompanied by a picture showing the bay and all its associated devices as they would be indicated on the system operator 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:

<table>
<thead>
<tr>
<th>Device</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
</table>

Device: Gives the name of the device and acts as a collector of all point information belonging to the device. The System Operator shall define the requirements where grouping is used.

Each binary status point can be mapped to one or two binary bits. In the case of a breaker or isolator, 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.

In the following sections, the TYPE column indicates the number of bits used to report the state of the point in question. The column headings indicate two bits but for single-bit points ignore the left-hand 0 or 1 value in the headings “01-State” and “10-State”.

1_state: This is the alarm state of the point.
0_state: This is the normal state of the point.

Double bit: 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 isolators.
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:

<table>
<thead>
<tr>
<th>Category</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Health</td>
<td>All alarm indications that refer to the health of the primary or secondary plant are assigned to this category.</td>
</tr>
<tr>
<td>Main Protection</td>
<td>All protection activity that is triggered by the Main 1 protection circuits is assigned to this category.</td>
</tr>
<tr>
<td>Backup Protection</td>
<td>Where backup protection is installed, such as on transformers, or where Main 2 protection is used, these alarms are assigned to this category.</td>
</tr>
<tr>
<td>Information</td>
<td>Pure state change data such as the state of a breaker or isolator are assigned to this category. As such, no alarming is associated with these points – the data presented is pure information.</td>
</tr>
</tbody>
</table>

Type

Indicates the type of point – single-bit, double-bit, analogue or binary change detection.

Control

Indicates if there is a supervisory control associated with the point

A5.1 Generator

The generator shall install operational measurements to specification from the System Operator 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:

Data Acquisition from generator to Gateway

Measurements of MW, MW set point and Mvar analog shall update the SCADA value from the source to the Gateway if the value changes by more than 0.5 MW or 0.5 Mvar. The maximum delay in this update shall be no longer than one second as shown in Figure 1 - Data collection time frame.
Figure 1 - Data collection time frame
Data Acquisition

The participant is responsible for the provision of communications facilities between the plant and the data terminal equipment as shown in Figure 1. See section 4 above for additional clarity related to the participant’s communication obligations.

The maximum delay for updating the Energy Management System shall be no longer than two seconds as shown in Figure 1.

The generator will provide the facility to set the jitter value of the measured data to a value between 1 and 5 bits to prevent the unnecessary messages being sent whilst maintaining the 0.5 MW or 0.5 Mvar accuracy required above. The System Operator will determine the exact number of bits required to be set for jitter tolerance for every installation.
(a) Gas turbines

Unit Analogs

<table>
<thead>
<tr>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Gross MW</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Gross Mvar</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Net MW</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Net Mvar</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Rotor RPM</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Stator kV</td>
<td>Info</td>
<td>Analog</td>
</tr>
</tbody>
</table>

Unit Status Points

<table>
<thead>
<tr>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Engine A</td>
<td>Ready</td>
<td>Health Single</td>
</tr>
<tr>
<td>Engine B</td>
<td>Ready</td>
<td>Health Single</td>
</tr>
<tr>
<td>GEN to SCO mode</td>
<td>Active</td>
<td>Info Single True</td>
</tr>
<tr>
<td>SCO to GEN mode</td>
<td>Active</td>
<td>Info Single True</td>
</tr>
<tr>
<td>Remote control</td>
<td>On</td>
<td>Info Single True</td>
</tr>
<tr>
<td>SCO start not ready</td>
<td>Alarm</td>
<td>Normal Health Single</td>
</tr>
<tr>
<td>GEN start not ready</td>
<td>Alarm</td>
<td>Normal Health Single</td>
</tr>
<tr>
<td>Under-frequency start</td>
<td>Armed</td>
<td>Off Health Single</td>
</tr>
<tr>
<td>Unit at Standstill</td>
<td>Yes</td>
<td>No Info Single</td>
</tr>
<tr>
<td>Unit auto load to base</td>
<td>Yes</td>
<td>No Info Single True</td>
</tr>
<tr>
<td>Unit auto load to minimum</td>
<td>Yes</td>
<td>No Info Single True</td>
</tr>
<tr>
<td>Unit in GEN mode</td>
<td>Yes</td>
<td>No Info Single</td>
</tr>
<tr>
<td>Unit in SCO mode</td>
<td>Yes</td>
<td>No Info Single</td>
</tr>
<tr>
<td>Unit load rate</td>
<td>Fast</td>
<td>Slow Info Single True</td>
</tr>
</tbody>
</table>

1 Note that where modes or functions are not available, such as SCO, the associated signals are not required.
<table>
<thead>
<tr>
<th>Event</th>
<th>Mode</th>
<th>Info</th>
<th>Single</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit to GEN mode</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single True</td>
</tr>
<tr>
<td>Unit to SCO mode</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single True</td>
</tr>
<tr>
<td>Unit to Standstill</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single True</td>
</tr>
<tr>
<td>Unit tripped and locked out</td>
<td>Alarm</td>
<td>Normal</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit under-frequency start</td>
<td>Initiate</td>
<td>No</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit islanded</td>
<td>Alarm</td>
<td>No</td>
<td>Health</td>
<td>Single</td>
</tr>
</tbody>
</table>
# (b) Hydro units

![Diagram of hydro units](image)

## 1.1 Unit Analogs

<table>
<thead>
<tr>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Frequency</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Gross MW</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Gross Mvar</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Net MW</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Net Mvar</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Stator kV</td>
<td>Info</td>
<td>Analog</td>
</tr>
<tr>
<td>Rotor RPM</td>
<td>Info</td>
<td>Analog</td>
</tr>
</tbody>
</table>

## Unit Status Points

<table>
<thead>
<tr>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Auto load</td>
<td>Active</td>
<td>Normal</td>
</tr>
<tr>
<td>Automatic power factor regulator</td>
<td>On</td>
<td>Off</td>
</tr>
<tr>
<td>Emergency Shutdown</td>
<td>Operated</td>
<td>Normal</td>
</tr>
<tr>
<td>GEN start not ready</td>
<td>Alarm</td>
<td>Normal</td>
</tr>
<tr>
<td>GEN to PUMP mode</td>
<td>Active</td>
<td>Off</td>
</tr>
<tr>
<td>GEN to SCO mode</td>
<td>Active</td>
<td>Off</td>
</tr>
<tr>
<td>Pump start not ready</td>
<td>Alarm</td>
<td>Normal</td>
</tr>
<tr>
<td>Pump to GEN mode</td>
<td>Active</td>
<td>Off</td>
</tr>
<tr>
<td>Pump to SCO mode</td>
<td>Active</td>
<td>Off</td>
</tr>
<tr>
<td>SCO start not ready</td>
<td>Alarm</td>
<td>Normal</td>
</tr>
<tr>
<td>SCO to GEN mode</td>
<td>Active</td>
<td>Off</td>
</tr>
<tr>
<td>SCO to PUMP mode</td>
<td>Active</td>
<td>Normal</td>
</tr>
<tr>
<td>Turning in gen direction</td>
<td>Yes</td>
<td>No</td>
</tr>
<tr>
<td>Turning in motor direction</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>

Note that where modes or functions are not available, such as SCO, the associated signals are not required.
<table>
<thead>
<tr>
<th>Under-frequency start</th>
<th>Armed</th>
<th>Off</th>
<th>Health</th>
<th>Single</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit at standstill</td>
<td>Yes</td>
<td>Normal</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit in GEN mode</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit in PUMP mode</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit in SCO mode</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit synchronising</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit to GEN mode</td>
<td>Active</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit to PUMP mode</td>
<td>Active</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit to SCO mode(^1)</td>
<td>Active</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
</tr>
<tr>
<td>Unit to Standstill</td>
<td>Active</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
</tr>
</tbody>
</table>
(c) **Steam units**

<table>
<thead>
<tr>
<th>Unit Breaker</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unit breaker state</td>
<td>Closed</td>
<td>Tripped</td>
<td>Info</td>
<td>Double</td>
<td>False</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Unit Signals</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross MW</td>
<td>Info</td>
<td>Analog</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gross Mvar</td>
<td>Info</td>
<td>Analog</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net MW</td>
<td>Info</td>
<td>Analog</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Mvar</td>
<td>Info</td>
<td>Analog</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Unit islanded</td>
<td>Alarm</td>
<td>No</td>
<td>Health</td>
<td>Single</td>
<td></td>
</tr>
</tbody>
</table>

(d) **System Operator to and from Power Station signals**

All manned *Power Stations* shall receive and provide the following signals to the *System Operator*:

<table>
<thead>
<tr>
<th>System Operator to Power Station</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reschedule</td>
<td>Initiate</td>
<td>Cancel</td>
<td>Info</td>
<td>Double</td>
<td>True</td>
</tr>
<tr>
<td>Emergency</td>
<td>Initiate</td>
<td>Cancel</td>
<td>Info</td>
<td>Double</td>
<td>True</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Power Station to System Operator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reschedule Initiated</td>
<td>Acknowledge</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Emergency Initiate</td>
<td>Acknowledge</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Emergency Cancel</td>
<td>Acknowledge</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
</tbody>
</table>

**Signal Description**

The *System Operator* staff initiates the action by activating the control function in the control room. The activation signal is sent via the BME to the *Generator* for action by the *Generator* staff. Note that once the *Emergency* signal has been sent to a *Generator*, and it has not been cancelled, the *Generator* should remain aware of the requirement to assist in delivering *Emergency* support.
Figure 2 – Example *Emergency* and Reschedule indication.

**Operation**: *Generator functions*: generators can implement the functionality differently such as fast flashing indicating *Emergency Level 1* in force received, keeping the light lit solid whilst *EL1* in force and acknowledged, slow flashing to indicate *Emergency Level 1* cancelled and off to indicate *Emergency Level 1* cancelled and acknowledged.

An alternative is to have the logic implemented on a standard PC screen using an internet browser.
Reschedule Initiated
The Reschedule function is sent by the System Operator to the generators via the BME and indicates that rescheduling took place that could result in a new generator schedule for the rest of the current day. There is no Cancel function for this action. When the power station staff acknowledge the request the requested state is reset.

Emergency Initiate
The Emergency initiate request from the System Operator is an indication that maximum generation is required.

Emergency Cancel
The Emergency Cancel indication from the System Operator is an indication that the Emergency assistance is no longer required.
Figure 4 – Example acknowledge push button behaviour

**Reschedule Initiate Acknowledge** The Reschedule Acknowledged indication from the Station is an acknowledgement from the station that rescheduling took place. (This indication should have an automatic reset based on a 15 minute timer) See Figure 4.

**Emergency Initiate/Cancel Acknowledged**

The *Emergency Initiate/Cancel* Acknowledged indication from the *generator* control room is an acknowledgement from the station that *Emergency* is in force or has be cancelled. (This indication could have an automatic reset based on a 15 minute timer).
(e) AGC signals

All Generating Units providing AGC shall provide and receive the following signals

<table>
<thead>
<tr>
<th>AGC signals from Generator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>High regulating limit</td>
<td></td>
<td></td>
<td>Health</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Low regulating limit</td>
<td></td>
<td></td>
<td>Health</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Ramp rate</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Set-point active power</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td>True</td>
</tr>
<tr>
<td>AGC – unit Status</td>
<td>On</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
<td></td>
</tr>
<tr>
<td>Frequency Bias</td>
<td>On</td>
<td>Off</td>
<td>Info</td>
<td>Single</td>
<td></td>
</tr>
<tr>
<td>Raise Block (optional)</td>
<td>High</td>
<td>Normal</td>
<td>Health</td>
<td>Single</td>
<td></td>
</tr>
<tr>
<td>Lower Block (optional)</td>
<td>Low</td>
<td>Normal</td>
<td>Health</td>
<td>Single</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>AGC signals to Generator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGC Raise Command</td>
<td>Raise pulse</td>
<td></td>
<td></td>
<td></td>
<td>True</td>
</tr>
<tr>
<td>AGC Lower Command</td>
<td></td>
<td>Lower pulse</td>
<td></td>
<td></td>
<td>True</td>
</tr>
</tbody>
</table>

**Signal description**

**High regulating limit**
This value gives the maximum allowable output AGC can raise the active power output. This is set at the generator. The high regulating limit can either be net active power or gross active power.

**Low regulating limit**
This value gives the minimum allowable output AGC can lower the generator. The low regulating limit can either be net active power or gross active power.

**Maximum Unit Gradient**
This is the maximum rate in (MW/min) which the unit can change whilst on AGC.

**Setpoint Value**
The setpoint value comes from the control equipment of the Generator. To change the active power output of the Generator, the output setpoint has to be adjusted. AGC controls the setpoint when AGC is on. The setpoint can either be net active power or gross active power.
AGC – Generator Status – (Set by the Power Station staff)
This signal indicates if the generator is allowing AGC. Only when signal is “on” can the System Operator select the generator to AGC operation. When this signal is “off”, all raise/lower commands from System Operator should be ignored.

Frequency Bias On
This indicates that primary governing is “on”.

Raise Block
In the event that the generator chooses not to allow AGC raise commands then the Raise Block is set. When this indication is set, all raise commands from the System Operator should be ignored.

Lower Block
In the event that the Generator wants to prevent AGC lower commands then the Lower Block is set. When this indication is set, all lower commands from System Operator should be ignored.

Raise/Lower Command
The Raise/Lower command consists of a message from the System Operator's AGC program instructing a particular unit to raise or lower its active power output by a predefined amount. The predefined amount is specified in terms of a rate of active power change (MW response per pulse received). The unit should be configured to interpret the amount and rate of active power change (MW) per pulse and the unit setpoint is adjusted appropriately.
(f) **Unmanned Unit or System Operator remote operation signals**

All units that are not manned for full or portion of the day or if it is agreed that the Generator must be capable of remote operation by the *System Operator*, then the following signals shall be provided and facilitated.

<table>
<thead>
<tr>
<th>Signals from generator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under frequency start ready</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Under frequency start armed</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Generator MW Setpoint (Gross or Nett)</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Regulation MW High Limit</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Regulation MW Low Limit</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Generator Mvar Setpoint⁵</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Generator kV Setpoint⁶</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Voltage or Q control mode⁷</td>
<td>V - Mode</td>
<td>Q - Mode</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Unit Controller status</td>
<td>Yes</td>
<td>No</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
<tr>
<td>Unit Load Limit⁸</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analog</td>
<td></td>
</tr>
<tr>
<td>Unit local AGC status</td>
<td>AGC</td>
<td>Local</td>
<td>Info</td>
<td>Double</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Signals to generator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>AGC Generator Status on</td>
<td>on</td>
<td>off</td>
<td>Info</td>
<td>True</td>
<td></td>
</tr>
<tr>
<td>Regulation High Limit Raise</td>
<td>Raise pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulation High Limit Lower</td>
<td>Lower pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulation Low Limit Raise</td>
<td>Raise pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Regulation Low Limit Lower</td>
<td>Lower pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator MW Setpoint Raise</td>
<td>Raise pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator MW Setpoint Lower</td>
<td>Lower pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator Mvar Setpoint’ Raise</td>
<td>Raise pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator Mvar Setpoint⁸ Lower</td>
<td>Lower pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator kV Setpoint⁹ Raise</td>
<td>Raise pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generator kV Setpoint¹⁰ Lower</td>
<td>Lower pulse</td>
<td></td>
<td>True</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Voltage or Q control mode¹¹</td>
<td>V - Mode</td>
<td>Q - Mode</td>
<td>Info</td>
<td>True</td>
<td></td>
</tr>
<tr>
<td>Primary Governing</td>
<td>On</td>
<td>Off</td>
<td>Info</td>
<td>True</td>
<td></td>
</tr>
</tbody>
</table>

³ Only applicable to units running in SCO mode
⁴ Only applicable to units running in SCO mode
⁵ Only applicable to units running in SCO mode
⁶ Maximum Load limit setting
⁷ Only applicable to units running in SCO mode
⁸ Only applicable to units running in SCO mode
⁹ Only applicable to units running in SCO mode
¹⁰ Only applicable to units running in SCO mode
¹¹ Only applicable to units running in SCO mode
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 an SVC, as well as full control by the System Operator.

(b) Interruptible load

All interruptible loads shall meet the minimum requirements. The System Operator 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 an interruptible load:

<table>
<thead>
<tr>
<th>Isolator</th>
<th>01_State</th>
<th>10_State</th>
<th>Category</th>
<th>Type</th>
<th>Control</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pole</td>
<td>Disagree</td>
<td>Normal</td>
<td>Health</td>
<td>Single</td>
<td>False</td>
</tr>
<tr>
<td>Isolator state</td>
<td>Closed</td>
<td>Open</td>
<td>Info</td>
<td>Double</td>
<td>False</td>
</tr>
<tr>
<td>Breaker</td>
<td>01_State</td>
<td>10_State</td>
<td>Category</td>
<td>Type</td>
<td>Control</td>
</tr>
<tr>
<td>Unit breaker state</td>
<td>Closed</td>
<td>Tripped</td>
<td>Info</td>
<td>Double</td>
<td>True</td>
</tr>
<tr>
<td>Current Transformer</td>
<td>01_State</td>
<td>10_State</td>
<td>Category</td>
<td>Type</td>
<td>Control</td>
</tr>
<tr>
<td>SF6 gas critical (CT)</td>
<td>Alarm</td>
<td>Normal</td>
<td>Health</td>
<td>Single</td>
<td>False</td>
</tr>
<tr>
<td>SF6 non-critical (CT)</td>
<td>Alarm</td>
<td>Normal</td>
<td>Health</td>
<td>Single</td>
<td>False</td>
</tr>
<tr>
<td>Load</td>
<td>01_State</td>
<td>10_State</td>
<td>Category</td>
<td>Type</td>
<td>Control</td>
</tr>
<tr>
<td>Load reduction acknowledged</td>
<td>No</td>
<td>Yes</td>
<td>Info</td>
<td>Single</td>
<td>True</td>
</tr>
<tr>
<td>Load interrupt acknowledged</td>
<td>No</td>
<td>Yes</td>
<td>Info</td>
<td>Single</td>
<td>True</td>
</tr>
<tr>
<td>Block load reduction acknowledged</td>
<td>No</td>
<td>Yes</td>
<td>Info</td>
<td>Single</td>
<td>True</td>
</tr>
<tr>
<td>----------------------------------</td>
<td>----</td>
<td>-----</td>
<td>------</td>
<td>--------</td>
<td>------</td>
</tr>
<tr>
<td>Return to service acknowledged</td>
<td>No</td>
<td>Yes</td>
<td>Info</td>
<td>Single</td>
<td>True</td>
</tr>
<tr>
<td>Load active power</td>
<td></td>
<td></td>
<td>Info</td>
<td>Analogue</td>
<td>False</td>
</tr>
</tbody>
</table>

The availability of the interruptible load shall be integrated into the ancillary service schedules by the market operator before the transfer to the System Operator.
APPENDIX 6: Operational schedules

(a) Energy schedules

A Generator’s bilateral contracted energy schedule (with any relevant TradeCo, including NEP (TradeCo)) shall be supplied to the System Operator in the format shown below:

<table>
<thead>
<tr>
<th>No</th>
<th>Data description</th>
<th>Format</th>
<th>Size</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>The official abbreviation of the power station name as defined by the System Operator.</td>
<td>Characters</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>The unit identification number.</td>
<td>Integer</td>
<td>0-99</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Contract hour</td>
<td>Integer</td>
<td>1-24</td>
<td>Hour</td>
</tr>
<tr>
<td>4</td>
<td>The contracted generation output per unit.</td>
<td>Integer</td>
<td>0-999</td>
<td>MWh</td>
</tr>
</tbody>
</table>

If not in a bilateral contract with a TradeCo (i.e. price sensitive Information is confidential and is not submitted to the SO), a Generator shall supply the Short-Run Marginal Cost (SRMC), for Generator energy, to the System Operator for dispatch (if required, according to the merit-order):

<table>
<thead>
<tr>
<th>No</th>
<th>Data description</th>
<th>Format</th>
<th>Size</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>The official abbreviation of the power station name as defined by the System Operator.</td>
<td>Characters</td>
<td>5</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>The unit identification number.</td>
<td>Integer</td>
<td>0-999</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Minimum generation capability of unit</td>
<td>Integer</td>
<td>999</td>
<td>MW</td>
</tr>
<tr>
<td>4</td>
<td>Price 1 = INC1</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>5</td>
<td>Minus elbow 1 = Elbow 1 - 1MW</td>
<td>Integer</td>
<td>999</td>
<td>MW</td>
</tr>
<tr>
<td>6</td>
<td>Elbow 1</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>7</td>
<td>Price 2 = INC1 + 0.02</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>8</td>
<td>Minus elbow 2 = Elbow 2 - 1MW</td>
<td>Integer</td>
<td>999</td>
<td>MW</td>
</tr>
<tr>
<td>9</td>
<td>Elbow 2</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>10</td>
<td>Price 3 = INC2</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>11</td>
<td>Price 4 = INC2 + 0.03</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>12</td>
<td>Price 5 = INC3</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>13</td>
<td>Price 6 = INC3 + 0.04</td>
<td>Real</td>
<td>999.99</td>
<td>RWF</td>
</tr>
<tr>
<td>14</td>
<td>Max generation</td>
<td>Integer</td>
<td>999</td>
<td>MW</td>
</tr>
</tbody>
</table>

The offer prices are submitted in the form of price blocks where the price in RWF/MWh is specified against output in MW for each Unit at the Power Station. The price offer indicates
the quantity of MWh per hour that the Generator is prepared to supply at the various price levels. An example price offer curve from a Power Station is given below.

The following parameters shall be specified:

- Unit Minimum Generation in MW (Mingen)
- Unit incremental prices (INC0 - INC4) in R/MWh
- Unit elbow points (Elbow 0, Elbow 1, Elbow 2, Elbow 3) in MW (these are outputs at which the incremental price changes)
- Unit Maximum Continuous Rating in MW (MCR)
- Unit Price for Emergency Generation in R/MWh (treated as the last incremental price INC4) also referred to as Emergency Bid Price (EMBP).

The price curve shall, further comply with the following:

- The number of elbow points (E) shall not exceed four.
- The number of incremental prices shall be one more than the number of elbow points.
- Each incremental price shall be greater than or equal to (but not less than) the preceding one, excluding INC0 which can be set independent of the other incremental prices.
- All incremental prices shall be positive.
APPENDIX 7: Post-dispatch information

The *System Operator* shall provide the following minimum operational information in near real time and as historic data in relation to each *Unit* at each *Power Station*:

<table>
<thead>
<tr>
<th>No</th>
<th>Data description</th>
<th>Format</th>
<th>Size</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Unit high limit</td>
<td>Real</td>
<td>999,99</td>
<td>MW</td>
</tr>
<tr>
<td>2</td>
<td>Unit low limit</td>
<td>Real</td>
<td>999,99</td>
<td>MW</td>
</tr>
<tr>
<td>3</td>
<td>Unit AGC mode CER/BLO</td>
<td>Character</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>Unit AGC status AUT/OFF/MAN</td>
<td>Character</td>
<td>3</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>Unit set-point</td>
<td>Real</td>
<td>99,99</td>
<td>MW</td>
</tr>
<tr>
<td>6</td>
<td>AGC pulse</td>
<td>Real</td>
<td>9,9</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Unit sent out</td>
<td>Real</td>
<td>999,99</td>
<td>MW</td>
</tr>
<tr>
<td>8</td>
<td>Unit auxiliary</td>
<td>Real</td>
<td>999,99</td>
<td>MW</td>
</tr>
<tr>
<td>9</td>
<td>Unit contract</td>
<td>Integer</td>
<td>999</td>
<td>MW</td>
</tr>
<tr>
<td>10</td>
<td>Unit spinning</td>
<td>Integer</td>
<td>999</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>32-bit flag on AGC settings</td>
<td>Integer</td>
<td></td>
<td>32 bits</td>
</tr>
</tbody>
</table>
The *System Operator* shall provide the following minimum operational information in near real time in relation to the overall dispatch performance:

<table>
<thead>
<tr>
<th>No</th>
<th>Data description</th>
<th>Format</th>
<th>Size</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>ACE (Area Control Error)</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>2</td>
<td>Average ACE previous hour</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>3</td>
<td>HZ system frequency</td>
<td>Real</td>
<td>99.999</td>
<td>MW</td>
</tr>
<tr>
<td>4</td>
<td>Frequency distribution current hour</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>5</td>
<td>Frequency distribution previous hour</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>6</td>
<td>System total generation</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>7</td>
<td>Control area total actual interchange</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>8</td>
<td>Control area total scheduled interchange</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>9</td>
<td>System operating reserve</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>10</td>
<td>System sent out</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>11</td>
<td>System spinning reserve</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>12</td>
<td>AGC regulating up</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>13</td>
<td>AGC regulating down</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>14</td>
<td>AGC regulating up assist</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>15</td>
<td>AGC regulating down assist</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>16</td>
<td>AGC regulating up emergency</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>17</td>
<td>AGC regulating down emergency</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>18</td>
<td>AGC mode</td>
<td>Char</td>
<td>TLBC / CFC</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>AGC status</td>
<td>Char</td>
<td>ON/ OFF</td>
<td></td>
</tr>
<tr>
<td>20</td>
<td>Area control error output</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>21</td>
<td>System transmission losses</td>
<td>Real</td>
<td>999.99</td>
<td>MW</td>
</tr>
<tr>
<td>22</td>
<td>Cross Border tie-line A</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>23</td>
<td>Cross Border tie-line B</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>24</td>
<td>Cross Border tie-line C</td>
<td>Integer</td>
<td>99999</td>
<td>MW</td>
</tr>
<tr>
<td>26</td>
<td>AGC performance indicators</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
APPENDIX 8: Generator performance data

Measurement of availability

The Unipede/Eurelectric standard for the measurement of plant availability must be used. Availability is measured with the use of an indicator known as the energy availability factor (EAF).

EAF represents the network point of view.

The EAF has the same conceptual content as the equivalent availability factor used by USA operators, e.g. the NERC-GADS data bank.

Energy availability factor is defined as the ratio of the available energy generation (b) over a given time period (PH) to the reference energy generation over the same period, expressed as a percentage. Both of these energy generation terms are determined relative to reference ambient conditions.

Available energy generation (b) for the purpose of calculating EAF is the energy that could have been produced under reference ambient conditions considering limitations within and beyond the control of the plant management.

\[ b = P_d \times PH \]

Reference energy generation (Y) is the energy that could be produced during a given time period if the unit were operated continuously at reference unit power (PM) under reference ambient conditions throughout the period.

\[ Y = P_M \times PH \]

Reference ambient conditions are environmental conditions representative of the annual mean (or typical) ambient conditions for the unit.

Alternative definition: The "energy availability factor" (f), over a specified period, is the ratio of energy (b) that the available capacity (Pd) could have produced during this period to the energy (Y) that the net maximum electrical capacity (PM) could have produced during the same period.

The energy produced (b) (or capable of being produced) by the available capacity (Pd) may also be calculated as the difference between the energy (Y) (the maximum electrical capacity...
- PM – that could have been produced) and the unavailable energy (c) (which was not produced or not able to be produced) by the total unavailable capacity (Pit).

\[ f = \frac{b}{Y} = \frac{Y - c \times 100\%}{Y} \]

Note: The parameter “c” is calculated from a summation of unavailable MWh due to outages and restrictions (planned, unplanned, external and non-engineering) occurring throughout the period from MW capacity loss x duration (hr) of the loss.

**Components of the energy availability factor (EAF)**

\[ EAF = UCF - OCLF \]

**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.

**Other capability loss factor (OCLF)**
Other capability loss factor is an indicator to monitor outage time and power reductions due to causes beyond the control of plant management.

**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 at least four weeks in advance.

**Unit capability factor (UCF)**
Note: UCF represents the **GENERATOR’S POINT OF VIEW**

The purpose of this indicator is to monitor progress in attaining high unit and industry energy production availability. This indicator reflects effectiveness of plant programmes and practices in maximising available electrical generation and provides an overall indication of how well plants are operated and maintained.
\[ UCF = 100 - PCLF - UCLF \]

**Measurement of availability and reliability**

The Unipede/Eurelectric standard for the measurement of plant reliability must be used.

Reliability is measured with the use of two specific indicators, namely unplanned automatic grid separations (UAGS) and successful start-up rate (SSUR).

**Unplanned automatic grid separations per 7 000 operating hours (UAGS/7000h)**

The purpose of this indicator is to enable monitoring of an important aspect of the reliability of service supplied to the electrical grid. It takes into account success in improving reliability by reducing the number of turbo generator trips. It also provides an indication of plant operation and maintenance performance.

Taking account of the number of operating hours when the turbo generator set is connected to the electrical grid enables assessment of required reserves. Furthermore, using a common standard for all grid separation data for each unit provides a uniform basis for comparison among units with values for the industry as a whole.

Intentional (manual) grid separations are not taken into account since operators should not be discouraged from taking action to protect equipment.

This indicator may be defined as corresponding to the number of unplanned (unintentional) automatic grid separations of internal origin that occur per 7 000 operating hours. This definition can be clarified as follows:

"Unplanned" means that grid separation is not an anticipated part of a planned test, nor part of an operating programme designed to adjust output to demand (e.g. a controlled shutdown). Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

"Grid separation" means the opening of the generator breaker or HV yard breaker where no generator breaker exists. This could be an opening signal actuated by overshooting of a safety threshold, or a spurious trip. Grid separation can only occur during grid service of the units. Grid service is obtained when the start-up is successful for requested start-ups or when loads in excess of the first synchronising load are reached for "contracted" or "other start-ups" (i.e. house or block load as programmed into the automatic synchronising equipment).
“Automatic” (unintentional) means that the grid separation is not the result of an action by the operator either on one of the switches to trigger a unit trip or grid separation or to simulate operation of a protection system.

Trips caused by the operator in error, e.g. opening the wrong switch leading to a trip, are excluded from the “manual” category. Controlled shutdowns of units where the line circuit breaker is manually or automatically opened at loads equal to or below the first automatic synchronising load should not be considered when computing this indicator.

“Operating” means that the turbo generator set is connected to the off-site grid (transmission of generated power) even if the alternator is operating in synchronous motor mode owing to exceptional circumstances.

"Of internal origin" means that the trip is due to an unspecified internal installation failure resulting in a loss of reliability – even if the initial event can be traced to an off-site cause. The signal that triggered grid separation must originate from one of the sensors (or protection logic) for monitoring unit parameters (turbo generator set and power transmission, up to and including the generator transformer HV breaker, and boiler). Grid separations actuated by protection systems for the physical parameters of the grid are not included unless they were incorrectly controlled.

The selected figure of 7,000 hours represents the typical number of on-line hours for most plants operating at base load or semi-base load. The indicator thus represents an approximate value of the actual number of grid separations occurring in one year.

The following data are required to determine the value for this indicator:

- The number of unplanned automatic grid separations (U) with the generator circuit breaker (or HV breaker where no generator breaker exists) in initially closed position
- The number of operating hours (OPH)

All automatic trips are counted for the UAGS indicator, including those auto trips occurring within +30 minutes of all requested start-ups that comply with the ±15-minute time limit for synchronisation.

\[
\frac{UAGS}{7000 \text{h}} = \frac{U \times 7000}{OPH}
\]

Data for new units is included in the calculation of industry values beginning January 1 of the first calendar year following the start of commercial operation. However, in order to be included in the industry value, the unit must have at least 1,000 operating hours per year. This
minimum operating period requirement reduces the effects of plants that are shut down for long periods of time and for which limited data may not be statistically valid.

Summarised definition of UAGS per 7 000 hours: This indicator tracks the average grid separation rate per 7 000 operating hours (approximately one year of operation) for units having at least 1 000 operating hours during the year. Only trips of internal origin to the installation are included and trips for the physical parameters of the grid are not included unless they were incorrectly controlled.

**Successful Start-up Rate (SSUR)**
The "successful start-up rate" is the ratio of the number of successful start-ups to the number of contracted start-ups over a given period of time. It measures the reliability of the service that is rendered to the customers.

\[
SSR = \frac{\text{NumberOfSuccessfulStartUps} \times 100\%}{\text{NumberOfContractedStartUps}}
\]

Start-up comprises the set of operations that enable the unit to be connected to the off-site power grid. Connection of the unit to the grid (closing the line circuit breaker) is the purpose of the first start-up phase, before loading and stabilisation at the required power level. Only this initial start-up phase, the success of which results in sustained grid connection, is considered here.

The contracted start-up refers to an agreement between the grid administrator (through any medium, e.g. verbally, telephonically, etc.) and the station, following a request from the grid administrator or the station. This forms part of a grid management schedule (hereafter referred to as the "real" National Control programme) for the full range of power generation resources (excluding tests). The request for a start-up in advance of the synchronising time corresponds to the technical delay due to equipment start-up times. This delay time can be reduced to almost zero in the case of start-up of peak-supply gas turbines with centralised, automatic control systems. For any given start-up contract, a precise time for grid connection and an implementation schedule are required (except for peak-load gas turbines). In the event of a sudden modification by the grid administrator of the grid connection contract time, within the start-up capabilities of the unit, a new contract needs to be entered into.

The following indicators are still under development:

- Protection management
- Ability to island
- Excitation system management
- Reactive capabilities
- Multiple-unit trip risks
- Governing requirements
- Restart after station blackout capability
- Black start capability
- Intermediate load capability
- External supply disturbance withstand capability
- Loading rates
**APPENDIX 9: Planning schedules**

Schedule 1: Ten-year demand forecast

<table>
<thead>
<tr>
<th>Year</th>
<th>Maximum demand</th>
<th>Expected minimum demand</th>
</tr>
</thead>
<tbody>
<tr>
<td>Measured (year 0)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year 1</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year 2</td>
<td></td>
<td></td>
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<tr>
<td>Year 3</td>
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<td></td>
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<tr>
<td>Year 4</td>
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<td></td>
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<td>Year 5</td>
<td></td>
<td></td>
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<td>Year 6</td>
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</tr>
<tr>
<td>Year 7</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year 8</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year 9</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Year 10</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Demand = Total Demand + Distribution Losses – Embedded Generation
Schedule 2: Embedded Generation with: MCR > Metering Threshold (kVA)

<table>
<thead>
<tr>
<th>Generator</th>
<th>Tx substation name at closest connection point</th>
<th>Operating power factor</th>
<th>Installed capacity (MW)</th>
<th>Plant type</th>
<th>On-site usage</th>
<th>Net sent out</th>
<th>Generation net sent out contribution at peak</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>Normal Peak</td>
<td>Normal Peak</td>
<td>Y 1</td>
</tr>
</tbody>
</table>
APPENDIX 10: Generator HV yard information

*TransCos* shall provide the following information to *Generators* about equipment and systems installed in HV yards from the *TransCo*. The *TransCo* shall provide stability criteria.

<table>
<thead>
<tr>
<th>Equipment</th>
<th>Requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td>Circuit breaker</td>
<td>MCR rating, peak rating, operating time, OEM, installation date</td>
</tr>
<tr>
<td>CT and VT</td>
<td>CT and VT ratings, classes of equipment, burdening, OEM, installation date</td>
</tr>
<tr>
<td>Surge arrestor</td>
<td>OEM, age, installation date, number of operations</td>
</tr>
<tr>
<td>Protection</td>
<td>Description of protection philosophy for all protection schemes and functions installed, including ARC; protection reliability information shall be available annually</td>
</tr>
<tr>
<td>Power consumption</td>
<td>List the power consumption requirement by equipment requiring supply from power station, including from AC, DC and UPS</td>
</tr>
<tr>
<td>Link</td>
<td>MCR rating, peak rating, OEM, installation date</td>
</tr>
<tr>
<td>Outgoing feeder</td>
<td>MCR rating, peak rating, erection date, length, impedance, transposition characteristics, thermal limits, installed protection, shielding</td>
</tr>
<tr>
<td>Transformer</td>
<td>Transformer specifications for coupling transformers in HV yards; the records of coupling transformers in HV yards must be available on request</td>
</tr>
<tr>
<td>Compressed air system</td>
<td>Compressed air system specifications including schematic drawings</td>
</tr>
<tr>
<td>Fault recorder</td>
<td>Fault recorder specifications including resolution, record time, triggering criteria, data format shall be provided on request; the <em>TRANSISCO</em> shall review the fault levels and impedance to network centre from HV yard, annually</td>
</tr>
</tbody>
</table>
THE RWANDA GRID CODE

Network Tariff Code

7 of 7 Code Documents

Version 1.0

January 2012

Enquiries: RURA, Rwanda
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1. **Introduction**

(1) This code sets out the objectives of network service pricing and the broad approach to revenue and tariff regulation with reference to the procedure to be followed in applications to change revenue requirements or the tariff structure.

(2) *The Authority* shall regulate the setting of prices and the structure of tariffs in the industry. *Licensees* shall therefore be regulated with regard to the prices and pricing structures they may charge *Customers*.

(3) *Customers* shall contract with their service provider for the payment of charges related to network services. These charges shall reflect the different services provided.

2. **Grid Code Overview**

(1) The Grid Code covers a range of technical, operational, commercial and Governance issues. In order to address these comprehensively in a structured way, the Grid Code is broken down into a number of “sub-codes”. These are:

   (a) The Preamble;

   (b) The Governance Code;

   (c) The Network Code;

   (d) The System Operations Code (including elements of Scheduling and Dispatch);

   (e) The Metering Code;

   (f) The Information Exchange Code;

   (g) The Network Tariff Code

(2) This document deals with the *Grid Code Governance* arrangements. It describes the process that will be followed to update the *Grid Code* to improve safety, reliability and operational standards. It sets out how *Grid Code* Participants can influence the amendment process and defines who has the authority to recommend and ultimately approve and enforce the changes. In addition the document also explains oversight
and compliance requirements that need to be observed by all Grid Code Participants.

(3) The Preamble document provides the policy and industry context for the Grid Code. It also sets out the legal and regulatory references from which the Grid Code derives its authority. Furthermore, the Preamble also contains a comprehensive list of definitions and acronyms for the various terms and abbreviations used in the suite of Grid Code documents.

3. Legal Authority

(1) In terms of the Electricity Law (N°21/2011 of 23/06/2011) as well as the RURA Law (N°39/2001 of 13/09/2001), the Authority is mandated with the obligation and is granted the powers to set, approve and enforce tariffs and fees charged by Licensees within the electricity supply industry.

(2) Such regulation of charges covers tariffs and fees for services offered by the various Licensed activities set out in the Electricity Law. The Network Tariff Code sets out key aspects relating to the economic regulation of Licensed transmission and distribution services.

(3) The Network Tariff Code sets out the objectives and principles of network service pricing, application of charges and fees and the procedure to be followed in applications by Licensees to change revenue requirements, tariff levels or tariff structure.

4. Tariff Requirements

(1) The Electricity Law (N°21/2011 of 23/06/2011) states that the Authority have the following responsibilities in terms of the regulation of tariffs:

(a) Prepare the principles relating to electricity tariffs which shall be approved by the Minister in charge of electricity.
(b) Set tariffs after consultation with the Minister in charge of electricity concerning the amount of the State subsidy.

(c) Approve balancing charges for transmission and system operation based on specified principles.

(2) Furthermore the Electricity Law states that tariffs and the tariff setting methodology must take the following into account:

(a) be transparent, accommodate the need for system integrity and reflect justified incurred costs, by minimizing risks in the sector of electricity transmission business and by ensuring competition while avoiding subsidies to the grid users;

(b) make sure each category of clients pays back the costs incurred on investments made without precluding the possibility to require some categories of clients to pay certain fees so as to promote an efficient use of electricity.

(c) help in recovering incurred costs, including capital financing costs invested in projected activities that allow a reasonable level of proceeds compared to the projected activities thereby improving on capacity building in terms of production and distribution activities as well as the capacity of delivering Ancillary Services. All this being aimed at attracting private investments and use of technology;

(d) include appropriate incentives to improve the quality of service to Customers;

(e) provide for a system of tariff decrease or increase following exceptional conditions.

(3) Other requirements set out in the Electricity Law include:

(a) The tariff conditions shall remain in force during a period determined in accordance with the agreed provisions of the License.

(b) Tariffs must ensure that the investor has a normal return on his/her investments. The capital investment shall be determined on the basis of infrastructure and Apparatus value used for the project implementation.

(c) All holders of electricity production, distribution, transmission, purchase and sale Licenses must publish their tariffs prior to their implementation in accordance with regulations in force.
(d) The regulatory agency shall have power to approve balancing charges for transmission and system operation based on specified principles.

(4) It is important to note that the *Electricity Law* has opened the electricity industry in Rwanda for private sector participation through investments in generation and network projects. To further support private sector participation, the *Electricity Law* also enables bilateral trading of energy between *Licensed* participants. This implies that participants will be able to transmit power across networks that they do not necessarily own or operate. However, this requires that network *Licensees* should ring-fence transmission, distribution and system operation costs and charges from other activities such as generation and trading. As such the Authority will regulate network tariffs separately from the other activities even if a participant has been *Licensed* to perform other functions.

5. **Scope and Applicability**

(1) The Authority will review and approve the levels of costs and the resultant revenue requirement for all network *Licensees* separately.

(2) The Authority will furthermore regulate the structure of network service charges in the industry.

(3) The Network Tariff Code sets out the key principles and approach to the establishment of the revenue requirement for a network business. It also outlines the options and considerations in respect of tariff structure for network services. These aspects are applicable to the tariffs charged by the network *Licensee*.

(4) The Network Tariff Code shall be read in conjunction with other documents associated with the regulation of tariffs and charges in the electricity supply industry. These include:

(a) Law N°21/2011 of 23/06/2011 Governing Electricity In Rwanda:

6. **Objectives of the Network Tariff Code**

(1) The Network Tariff Code shall support the duties of the Authority as set out in the relevant Laws, including:

(a) Promote effective competition and economic efficiency;
(b) Protect the interests of consumers;
(c) Protect the financial viability of efficient suppliers;
(d) Promote the availability of regulated services to all consumers;
(e) Enhance public knowledge, awareness and understanding of the regulated sectors; and
(f) Take into account the need to protect and preserve the environment.

(2) The Network Tariff Code is aimed at ensuring that the approved revenue requirement supports a viable and efficient network business.

(3) In support of private sector participation the Network Tariff Code will seek to ensure that network tariffs are designed in pursuit of the following objectives:

(a) Open access to *transmission* services at equitable, non-discriminatory prices for all *Customers*;
(b) Pricing levels that recover the approved revenue requirements of *transmission or distribution Licensee(s)*;
(c) Revenue requirements that support a viable and efficient network business;
(d) Predictable prices over time to *Customers*;
(e) Pricing signals that reflect the underlying cost structure of the services provided;
(f) Optimal asset creation and utilization; and
(g) Unbundling of service offerings and cost-reflective pricing of each service component over time.
7. **Principles for regulation of income**

(1) *The Authority* shall employ a published regulatory guideline to define the form of regulation and the methodology by which the revenue requirements and associated tariffs/charges shall be determined.

(2) In broad terms, the revenue requirement and tariffs/charges approved by *the Authority* shall reflect prudently incurred costs, including efficient operating and maintenance expenses, line loss costs, *Customer* services expenses, depreciation and a reasonable return on invested capital for facilities that are used and useful in providing the regulated service.

8. **Tariff Methodology Overview**

(1) In the regulation of electricity tariffs, there are essentially three key aspects to consider:

   (a) Allowable revenue requirement – the level of revenues that the regulated entity is allowed to recover to cover prudently incurred costs plus a fair return for investors;

   (b) Tariff structure – the different tariff components and any differentiation applied, as well as the allocation of costs to different tariff components and/or *Customer* categories; and

   (c) Tariff categories - the grouping of *Customers* into predefined categories in order to reflect the cost of supply while keeping tariffs simple.

(2) It is worth highlighting that the proposed approach may entail multiple iterative engagements between the *Regulatory Authority* and the *Licensee* in reviewing and making any adjustments to the revenue requirement and tariff levels.

(3) The approach to determining the revenue requirement is discussed in section 9, tariff categories are addressed in section 12 while tariff structuring considerations are discussed in section 11 and the tariff application and approval process is set out in section 7 below.
9. Determination of Revenue Requirement

(1) The regulatory tariff methodology shall identify the key considerations in respect of cost elements insofar as they impact on the revenue requirements of the network business.

(2) The high level categories of costs that make up the revenue requirement shall include:

(a) Operation and maintenance costs;

(b) Cost of network losses;

(c) Customer service and administration costs;

(d) Depreciation, and

(e) Investment return

(3) Key considerations relating to each of these are set out below.

9.1. Depreciation

(1) Together with regulatory returns, an allowance for depreciation ensures that investors are properly compensated for their capital investments. There are a number of factors to be considered in determining the allowed depreciation levels. Given that depreciation is based on asset values, the charge methodology identifies allowable versus non-allowable assets as well as the method of asset valuation to be applied. These aspects enable the establishment of the Regulatory Asset Base (RAB), which serves as a vital determinant of the revenue requirement and associated prices.

9.2. Allowed Assets

(1) It is noted that the following asset classes are typically included in the rate base:

(a) Used and Useful Assets - assets used in the network of electricity as well as in the operation of the wholesale market and control of the power system.
(b) Inventory. This includes materials, spares and fuel stock holdings.

(c) Net Working Capital. To fund on-going operations

(2) The methodology identifies certain asset classes to be specifically excluded from the regulatory asset base. These typically include:

(a) Subsidized Assets. These are assets not paid for or funded by the utility. Partially paid for and funded assets are allowed on a proportional basis. The inclusion of subsidized assets in the regulatory asset base would allow the benefit of an income stream that the regulated entity has not financed.

(b) Future Assets. These should be excluded from the regulatory asset base until they are used and useful (i.e. enter into commercial operation).

(3) Inventories including materials, spares and fuel stock holdings may be included in the RAB but limits should be applied to prevent excessive inventories and stockholding. For example the Authority may apply a maximum amount not exceeding 5% of the Licensee’s re-valued un-depreciated asset base.

(4) Net working capital required to fund on-going operations may be included in the RAB. This is determined as the net of trade and other receivables (debtors) and payables (creditors). The Authority may decide to impose limits on debtor days to prevent inefficiencies being passed on to electricity consumers. For example the Authority may apply a maximum debtors’ day of 60.

(5) Assets not complying with the above criteria are not included in the RAB. These would include, for example:

(a) Financial investments, cash and cash equivalents are not included in the RAB. These are deemed to earn a return independent of the regulated environment.

(b) Prepayment credit and Customer deposits.
9.3. Asset Valuation Approach

(1) The most common asset valuation methods are listed below, noting that the methods vary substantially and yield diverse asset valuations, each with specific preferred areas of application. These include

(a) Historic Cost Accounting:

(b) Current Cost Accounting

(c) Indexation approach.

(d) Absolute valuation (revaluation) approach.

(e) Modern Equivalent Asset

(2) The most widely used approach, in countries with low to moderate levels of inflation, is the historic cost accounting approach.

(3) Countries with moderate to high inflation rates could benefit by adopting the current cost accounting or even the revaluation approach.

(4) Indexation approach is often used in conjunction with revaluation approach to adjust the RAB in the years when a full revaluation has not been done. Utilities that use this approach typically revalue assets every 5 years to safe cost.

(5) The modern equivalent asset approach is used in a few countries to ensure Customers don’t pay for any unused or inappropriate assets. This approach although theoretically sound has some practical implementation challenges.

9.4. Depreciation Method and Period

(1) The depreciation method and period are important in determining the depreciation expense allowed as well as depreciated asset values.

(2) It is anticipated that, unless agreed otherwise, depreciation is based on the prevailing accounting approach for each regulated entity.
(3) However, many examples exist where regulators have set predefined depreciation periods for tariff determination purposes that are different from accounting requirements.

9.5. Investment Returns

(1) Network infrastructure is highly capital-intensive with long asset lives. Hence it is pointed out that regulators do not typically allow network companies to recover the cash costs associated with investments via tariffs, but rather facilitate such recovery via an allowable return. This approach implicitly takes account of the cost of capital and, if set at the appropriate level, allows the utility to fund investments.

(2) In this regard it is important to ascertain the regulatory asset base upon which such return is earned as well as a fair return level to sustain the business(es). The allowed Rate of Return (ROR) is a key regulatory parameter for the revenue requirement.

(3) The choice of a real or nominal ROR is informed by the valuation approach adopted. The Historic Cost Accounting approach proposed requires the application of a nominal ROR to ensure that inflationary impacts are properly incorporated. Similarly, current or re-valued asset values require the application of a real ROR.

(4) The methodology, furthermore defines whether a pre-tax or a post-tax ROR is applied.

(5) The determination of a “fair” or “reasonable” ROR is defined as the risk-adjusted return that suppliers of funds to the business would require. In general, businesses use a combination of debt and equity to finance investments. The appropriate return on capital is thus the weighted average cost of debt and equity financing. This debt weighted average is referred to as the Weighted Average Cost of Capital (WACC). See Annexure A in section 16 for a detailed discussion of the determination of the Rate of Return.
9.6. Operating and Maintenance costs

(1) Network operating and maintenance costs are the costs associated with operation and maintenance of the various lines and substations as well as the system. This includes a range of costs including

(a) Human resources cost
(b) Network maintenance cost
(c) Ancillary service procurement cost
(d) Congestion cost (out of merit dispatch to adhere to transfer constraints)
(e) Balancing cost (the cost to restore system to balance following a deviation in bilateral energy agreements)

(2) There are also operating costs related to the activities of the System Operator. This includes costs associated with Ancillary Services, control centres, facilities and staffing for power system operations, management and administration of the wholesale market as well as supporting information, control and scheduling, dispatch and settlement systems.

(3) The following could serve as a guideline on what costs to include and what costs to exclude in the determination of the revenue requirement.

(a) Expenses must be incurred in an arm’s length transaction.
(b) Expenses must be incurred in the normal operation of generation, transport and supply of electricity, including a reasonable level of refurbishment, repairs and maintenance costs.
(c) Expenses must be prudently and efficiently incurred after careful consideration of available options. Such consideration would include, for example, a competitive and transparent procurement process.
(d) The costs and benefits associated with network losses shall be incorporated with appropriate incentives to contain these to acceptable levels.
(e) For any expenses incurred under extraordinary circumstances (due to, for example, exogenous factors) consideration shall be given to spreading such expenses over a number of years.

(f) Limited expenses for research and development may be included at the discretion of the Regulatory Authority.

(g) Expenses on advertising related to the core business of supplying electricity may be included in the revenue requirement calculation where these are, for example, educational, or serve to enhance the sector.

9.7. Customer Service and Administration related costs

(1) Customer Service costs generally include the costs associated with meter reading, billing, invoicing, and Customer support as well as all the other costs related to Customer and revenue management cycle activities. Administration costs include the costs of buildings, administrative staff, overheads etc.

(2) For network companies, these costs are typically small and are therefore often included with the operating and maintenance cost category.

9.8. Cost of Network Losses

(1) Electrical losses arise from the physical laws that govern the transport of electricity. The cost of losses thus represents a legitimate expense that must be recovered.

(2) In terms of costing losses, charges may be based on marginal or average losses. Although marginal loss based charges tend to provide stronger pricing signals, this results in over-recovery against the actual costs of losses. By contrast charges based on average losses would be more consistent with the overall approach of ensuring full cost recovery.

(3) The cost of losses therefore comprises the loss amount (kWh) multiplied by the average energy purchase cost (c/kWh).
9.9. **Incorporating Incentives in Regulation**

(1) The revenue requirement determination outlined above is in essence cost-plus approach, with limited incentive for the regulated entity to improve operations or to invest prudently. It is believed that this approach is appropriate in the early stages of regulation, while the *Regulatory Authority* establishes itself as a regulator, and collects information on the industry. As the regulated entities begin to reform their prices to be consistent with the recommended approach, a subsequent stage can be the gradual introduction of incentive elements to regulation.

(2) Regulation can be designed to provide a range of incentives. Some of these are briefly reviewed below.

### 9.9.1. Incentives to improve operating costs

(1) There are a number of ways of providing incentives to improve operating costs, including incentives to reduce losses and operating costs.

(a) Incentives to reduce losses. The *Regulatory Authority* can set prices based on a target for losses, rather than actual losses. This target can be progressively tightened over time until network operators reach what is regarded as acceptable levels. If a network operator is able to reduce losses faster than the target, profits will be increased and this should not be taken away through reconciliation adjustments. However the opposite also applies in that underperformance against targets should not be undermined via reconciliation adjustments.

(b) Incentives to reduce operation costs. The *Regulatory Authority* can set a target to reduce overall operating costs, in real terms, over time. Again the financial benefits and penalties of exceeding or failing to meet targets should not be negated by reconciliation adjustments.

### 9.9.2. Incentives to optimize investment

(1) This can be more difficult to implement. At one level, the *Regulatory Authority* can subject investment plans to scrutiny (so-called prudency reviews) and decide
whether these plans are justified, and hence included in the rate base. Similarly, any cost overruns on projects can be scrutinized to decide whether they are justified or not. If not, the cost overrun can be excluded from the RAB. While this review process does act as a powerful incentive to be careful with investment decisions and their implementation, it does add considerably to the administrative burden and is likely to increase regulatory risk.

(2) It is worth noting that the criteria that assets must be “used and useful” in order to be included in the regulatory asset base provides the Regulatory Authority with an additional mechanism to incentivize efficient investment. The Regulatory Authority thus has the discretion of excluding assets if the investment is deemed unnecessary.

(3) It is proposed that the Regulatory Authority seeks to include incentive elements into tariff regulation as a second stage only in the development of its regulatory regime. This should be introduced once the regulated entities have become familiar with the proposed method, and have successfully implemented it. By this stage the Regulatory Authority should have built up a suitable information database to facilitate the design of incentive mechanisms and setting of relevant parameters.

10. Cost Structure versus Tariff Charges

(1) The basic principle to be employed by the regulated entity in structuring tariffs is to seek optimal cost-reflectivity by retaining these as tariff components and mapping the respective costs to them.

(2) The cost structure of the majority of network entities consist of the following components:

(a) Variable cost. These are costs that are usually associated with energy procurement costs as well as any operating and maintenance costs that vary with sales.

(b) Fixed network cost. These are costs related to infrastructure establishment and any operating and maintenance cost that do not vary with sales.
(c) Fixed Customer cost. Consist of Customer service related costs including metering, billing and Customer care.

(3) Ideally, the different electricity charges should reflect and be aligned with the various cost components. This is critical to provide the right signals to the Customer especially when energy conservation or demand side management has to be achieved. This means that:

(a) Revenue from the energy charges should recover the costs related to variable costs such as energy procurement, i.e. FRW / kWh

(b) Similarly, demand charges should recover the costs related to fixed network costs i.e. FRW / kVA and

(c) Fixed charges should reflect the Customer supply related costs, i.e. FRW / connection / month.

(4) In seeking to achieve cost-reflectivity in charges levied, it is noted that there are a number of different network charge components that may be applied. Each charge component is designed to recover specific network costs in the most economically efficient way. These components are:

(a) Connection Charges: The connection charge is a Customer-specific charge to new Customers to cover expenses incurred to establish network infrastructure for the benefit of the new Customer. This connection charge is generally applicable to both Generators and loads using the network system. The principal requirement that each Customer pay for the costs that he or she directly induces on the grid (e.g. his own connection-line) is well justified and provides a suitable signal of the cost that this Customer incurs by connecting to the network.

(b) Customer service charges: The cost for providing Customer related services such as metering, billing and Customer queries.

(c) Line loss charges: These charges are designed to recover the variable costs of the network entity. These costs consist primarily of network losses but could include other variable costs.
(d) Balancing charges: The cost to restore the system to balance following a deviation event by one or more of the parties that have entered into bilateral contracts.

(e) Use of System Capacity Charges: The purpose of the network use-of-system charge is to recoup the costs for establishing, operating and maintaining the network infrastructure which have not been recouped via connection [or other network] charges. The approach is depicted in the following figure:

(f) Congestion charges: Recover the cost of network congestion (out of merit dispatch)

(g) Reliability charges: Recover cost of the procurement of ancillary services including, reserves, voltage control and blackstart\(^1\).

(5) It is important to emphasise that not all the charges will be unbundled initially. The pace at which unbundling will take place will be set by the Regulatory Authority and will be driven by factors such as the need of the market for the unbundled services as well as the experience and understanding of the market participants. The Regulatory Authority should lead the process through a proper implementation plan as well as capacity building initiatives. The diagram below illustrates various stages of tariff unbundling (shown by the different Structures) to more accurately reflect the cost of supply.

\(^1\) It is very hard to quantify the costs associated with providing reactive energy. In most cases only a signal can be provided to ensure that Customers manage their power factor correctly, such as reactive energy charges or charging for demand costs on a FRW/kVA basis and not FRW/kW. If, however, the cost of providing reactive energy is unbundled, it may be charged as a FRW/kVARh charge.
11. **Define Tariff Structure**

(1) Tariff differentiation represents an important element of tariff structuring. In broad terms, pricing may be differentiated on the basis of a number of cost drivers. For electricity pricing, the most important of these include geographic location, voltage level, and time-of-use.

11.1. **Generators and Loads**

(1) One of the key considerations in respect of network price differentiation is the allocation of costs between the two groups of users of the network infrastructure, namely the *Generators* and the loads. It is difficult to recommend a “best practice” for cost allocation between *Generators* and loads. However, four issues are generally considered.

(a) Firstly, the relationship of network charges to those applied in neighbouring markets should be taken into account. Adopting an allocation that harmonizes charges with those of electricity trading partners will arguably be beneficial.
(b) Secondly, the decisions should be consistent with national strategies and priorities.

(c) Thirdly, any final position should be tested against the principles of network tariff pricing, including that of fairness. An equal split of costs between Generators and loads is viewed by most market participants as the fairest allocation.

(d) Finally, simplicity and ease of implementation. Clearly the benefits of any selected approach needs to be offset against the complexity and costs introduced.

(2) In the early stages of network charging in Rwanda it is recommended that Generators will not pay use of system charges. This approach has been adopted to simplify the commercial interfaces in the initial phases of implementing the new market arrangements. At a later stage the Regulatory Authority may introduce use of system charges for Generators. However, Generators will be required to pay for connection and use of system energy charges from the start.

11.2. Geographic location

(1) Geographically differentiated tariffs are typically considered where there are significantly different costs imposed by delivery to particular geographic locations. There are several possibilities for geographic variation including

(a) Postage Stamp Pricing (same price in all areas – uniform pricing)

(b) Zonal pricing (prices differentiated by predefined geographic area)

(c) Nodal pricing (prices are different at every node / sub-station)

(2) In terms of geographic differentiation, postage stamp and nodal pricing approaches represent two extremes ranging from the simplest to the very complex. Zonal pricing is often deemed to represent a good compromise between the two extremes.

(3) However, many countries have a policy of national uniform tariffs which essentially prevents charges from being differentiated on the basis of geographic location.
11.3. Voltage level

(1) Electricity supply tariffs are often differentiated by voltage level as different Customer off-take voltages generally entail different infrastructure and associated different costs. In particular, electricity delivery at a lower voltage is often deemed to use both higher voltage and lower voltage networks whereas electricity delivery to higher voltage is deemed to use only higher voltage networks.

11.4. Time of Use Differentiated Tariffs

(1) Time differentiation of tariffs is based on the recognition that costs vary by time. In particular, network use during times of peak stress on particular network elements drives the need for new capacity and hence occasions greater costs than network use at other times.

(2) Time-of-use differentiation is considered to be a powerful tool for ensuring cost-reflectivity and promoting energy efficiency.

(3) Many utilities use time of use to differentiate energy charges (e.g. line loss charges). However, few utilities differentiate demand charges on a time of use basis because these charges are often used to recover the cost network infrastructure which does not change with time of day or season.

12. Define Tariff Categories

(1) All tariff methodologies require that Customers are grouped into different categories. The purpose is to support the development of cost reflective tariffs (by grouping together Customers with a similar cost of supply profile or structure) and to simply and therefore reduce the cost of Customer management.

(2) There are several options that could be used to group Customers. One option which has found widespread support in many parts of the world is to group Customers according to their economic activity. This approach is based on the assumption that electricity Customers with the same economic activity impose a similar cost burden
on the electricity provider. The following are examples of Customer categories that are based on economic activity; agriculture Customers, mining Customers, hospitals, government buildings, etc.

(3) However, there is an increasing trend amongst electric utilities to move away from using Customer economic activity as a differentiator of tariff categories. Instead, Customers are grouped based on their supply and consumption characteristics. The main purpose of course is to define tariff categories which are fair, cost reflective and simple to use. The table below shows how Customer supply characteristics can be used to define tariff categories that are independent of economic activity.

<table>
<thead>
<tr>
<th></th>
<th>Tariff A (Very Small)</th>
<th>Tariff B (Small)</th>
<th>Tariff C (Medium)</th>
<th>Tariff D (Large)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Commercial</td>
<td>1) Pre-Pay</td>
<td>1) Pre-Pay</td>
<td>1) Demand</td>
<td>1) TOU</td>
</tr>
<tr>
<td></td>
<td>2) Credit</td>
<td>2) Credit</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Phase</td>
<td>1) Single &amp;</td>
<td>1) Single &amp;</td>
<td>Any</td>
<td>Any</td>
</tr>
<tr>
<td></td>
<td>2) Multi</td>
<td>2) Multi</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Voltage</td>
<td>≤ 400 V</td>
<td>≤ 400 V</td>
<td>≤ 30 kV</td>
<td>&gt; 30 kV</td>
</tr>
<tr>
<td>Size</td>
<td>≤ 80A</td>
<td>&gt; 80 A</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**FIGURE 2 EXAMPLE OF TARIFF CATEGORIES**

13. **Subsidies, Cross-Subsidies and Levies**

(1) The key differences between subsidies, cross-subsidies and levies are summarised below:

(a) A subsidy refers to a payment or benefit received by a Customer (or Licensee) from a party that is not directly involved in the electricity industry. For example a grant from the GOR or an aid agency.

(b) A cross-subsidy is when a Customer (or Licensee) receives payment or benefit paid for by another Customer (or Licensee) within the electricity industry. It usually arises when tariffs are determined on the basis of affordability (paying capacity) of the
consumers rather than the actual cost of serving them. The consumers paying the higher-than-cost tariffs are said to be 'cross-subsidizing' the consumers paying the lower-than-cost tariffs. Another form of cross subsidy exists between regions. It follows that if a country follows a national tariff policy and there are regions that are densely loaded as compared to others there is bound to be geographical cross subsidies present in the system.

(c) A levy (or surcharge) refers to a payment by a Customer (or Licensee) to a party that is not directly involved in the electricity industry. For example a levy on tariffs to subsidise other GOR projects, initiatives or services such as broadcasting, municipal services, elections, etc.

(2) Cost reflectivity of tariffs can refer to a variety of issues, including:

(a) How well do overall average tariff levels meet overall average costs (overall cost reflectivity)

(b) How well do the total revenues which are recovered from an individual Customer class reflect the costs of serving that class (cross subsidy)

(c) How well do the individual tariff elements for each Customer class reflect both the level and structure (fixed, variable, etc) of the costs of serving that Customer class (tariff structure reflectivity)

(3) The introduction of bilateral trading arrangements as foreseen in the Electricity Law will expose and drive-out any hidden subsidies that may be embedded in the tariffs for Contestable Customers.

(4) In order to retain the ability to cross-subsidise under the new market structure arrangements it is important that Rwanda introduces transparent cross-subsidies. This should be done in accordance with a subsidy framework. International agencies, including the World Bank, have detailed studies to understanding energy subsidies and the role they play in development, and this work has concluded a few important lessons which should be kept in mind whenever a subsidy framework is developed:

(a) **Subsidies should be targeted**: They should be targeted to desired beneficiaries, thus minimizing their distorting effect on the economy as a
whole. For this reason, “demand side” subsidies are often superior to “supply side” support.

(b) **Subsidy contributors should be clearly identified:** The subsidy framework must clearly indicate who will contribute to the subsidy or cross-subsidy. Potential contributors include, other: Government, aid agencies, other Customers.

(c) **Subsidies should be transparent:** When subsidies are hidden, or difficult to track, the important fact that they are a public policy choice becomes obscured. Tariff cross-subsidies among electricity ratepayers are a good example of such hidden subsidies.

(d) **Capital cost subsidies are preferable to operating cost subsidies:** Direct support for system investment costs, or initial connections costs for new consumers, bear less distortion than on-going support payments that send an incorrect price signal to consumers.

(e) **Operating cost subsidies, if necessary, should be time-limited:** Although they should be avoided, operating cost subsidies are sometimes necessary in the case of an economic shock, but they should not be allowed to become a regular source of funding power sector operations.

(f) **Efficient Mechanisms:** The mechanisms for the collection and disbursement of benefits and payments should be clearly defined and should be efficient.

(g) **Subsidies (or cross-subsidies) to promote energy access may be justifiable:** These may come in the form of subsidies to lower the initial cost of connection, or to offer lifeline tariffs for a minimal level of consumption, for consumers who would not otherwise be served. Such subsidies have successfully offered access to poor people without creating significant distortions in national energy markets.

(5) However, policy makers should exercise care when developing the subsidy framework. Subsidies, cross-subsidies and levies usually drive electricity prices away from the real cost of supply resulting in sub-economic outcomes. For example:

(a) If tariffs are below the cost of supply it could result in wastage. This will result not only in inefficient use of electricity but will also result in higher levels of pollution.

(b) Subsidies could result in tariff discrimination and unfair pricing arrangements
(c) If tariffs are above the cost of supply it be prevent the development and expansion of economic activity resulting in lower overall economic growth.

(6) Notwithstanding the above, carefully designed support mechanisms can provide meaningful support in making electricity more affordable especially for low income Customers.

14. Tariff Review Period

(1) The Electricity Law allows the Authority to set tariff conditions for a defined period as set out in accordance with the agreed License provisions. Regulators typically set tariffs for:

(a) A 1-year period. In other words tariffs are reviewed and adjusted annually.

(b) A 3-year period. Tariffs are reviewed and adjusted every 3 years. Interim adjustments are made via an agreed tariff adjustment formula.

(c) A 5-year period. Tariffs are reviewed and adjusted every 5 years. Interim adjustments are made via an agreed tariff adjustment formula.

(2) The advantage of reviewing tariffs more frequently is that tariffs levels will track the cost of supply closely but the downside is that it results in a heavy administrative burden on the Licensee and the regulator to prepare, calculate and approve the new tariffs. Longer review periods lessen this burden but tariffs may drift away from the cost of supply depending on the tariff adjustment formula.

(3) The tariff adjustment formula, if used, typically consider the following aspects:

(a) the cost of fuel;

(b) the cost of power purchases or the rate of inflation;

(c) currency fluctuation, and

(d) Sales volumes and mix changes

(4) The Regulatory Authority generally shall not consider the adjustment of a new rate or charge in between review periods. A Licensee may, however, petition the Authority
for a waiver of this provision if it can be shown that a material undue hardship would occur in the absence of such a revision.

15. **Tariff Application, Approval and Notification Processes**

(1) The *Electricity Law* (N°21/2011 of 23/06/2011) states that the Authority have the following responsibilities in terms of the regulation of tariffs:

(a) Prepare the principles relating to electricity tariffs which shall be approved by the Minister in charge of electricity.

(b) Set tariffs after consultation with the Minister in charge of electricity concerning the amount of the State subsidy.

(2) The network Licensee shall submit detailed cost, sales and other relevant information in accordance with the Authority’s requirements and timeframes.

(3) The tariff application shall be accepted, evaluated and approved by the Authority in accordance with the provisions of the Authority’s Tariff Application Guidelines of 2009.

(4) Once the Minister has approved the new tariffs and charges the network Licensee shall notify all its Customers using acceptable communications channels as soon as possible.
16. Annexure A: Calculation of the Rate of Return

16.1. General Approach

(1) A key question flowing from the legislation is what constitutes “a reasonable return on investment”. The vast majority of international and regional regulators consider a return on investment that is equal to the Licensee’s Weighted Average Cost of Capital (WACC) as fair and reasonable. This approach is also supported by economic theory and financial modelling. The reason is that a ROR that matches the WACC is considered a fair return since the WACC reflects the lenders’ and investors’ return expectations.

(2) There are essentially two main sources of capital or funding, namely debt and equity. Debt capital includes all long term borrowing incurred by a firm, including issuing of corporate bonds. Equity capital consists of long term funds provided by the firm’s owners, the shareholders. A firm can obtain equity either internally, by retaining profits rather than paying them out as dividends to its shareholders, or externally by issuing and selling shares. The key differences between debt and equity capital are summarised in Figure 3 below.

FIGURE 3: KEY DIFFERENCES BETWEEN DEBT AND EQUITY CAPITAL

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Debt</th>
<th>Equity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Voice in Management¹</td>
<td>No</td>
<td>Yes</td>
</tr>
<tr>
<td>Claims against income and assets</td>
<td>Senior to equity</td>
<td>Subordinate to debt (first pay debt and if there is money left then pay equity)</td>
</tr>
<tr>
<td>Maturity (expiry)</td>
<td>As agreed with lender</td>
<td>None</td>
</tr>
<tr>
<td>Tax treatment</td>
<td>Interest can be deducted from tax</td>
<td>No deduction from tax</td>
</tr>
</tbody>
</table>

¹. In the event that the firm violates its stated contractual obligations to them, debt holders and preferred shareholders may receive a voice in management, otherwise only common shareholders have voting rights.

(3) It is important to note that the costs of equity financing are generally higher than the cost of debt. The first reason for this is that the suppliers of equity capital take more risk because of their subordinate claims to revenue and assets. The second is that interest can be deducted from tax resulting in a lower cost of debt. However, despite
being more expensive, equity capital is necessary for a firm to grow and to keep default risk at acceptable levels.

(4) The WACC is calculated as a nominal pre-tax figure\(^2\) and is determined according to the following formula:

\[
WACC = gD + (1-g)K
\]

Where;

- \(WACC\) = Weighted Average Cost of Capital (no tax WACC)
- \(g\) = target gearing (net debt as a % of net funding)
- \(D\) = Cost of Debt
- \(K\) = Cost of Equity

16.2. Cost of Debt

(1) The Cost of Debt is defined as:

\[
D = (r_f + \rho)
\]

Where;

- \(D\) = Cost debt (nominal before tax)
- \(r_f\) = risk-free rate
- \(\rho\) = debt premium

(2) As can be seen from above the expected cost of debt consists of the expected (market) risk-free rate and expected (firm specific) debt premium.

(3) The risk free rate is determined using spot prices of selected long term maturity bonds appropriate to the Rwandan market (as set out under 16.5 below).

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\(^2\) A nominal rather than real ROR is applied to match the historic cost valuation approach applied to the Regulatory Asset Base. Pre-tax figures are applied to simplify the calculations. An alternative approach is to use a real pre-tax WACC on an inflation-adjusted RAB. Both approaches will produce the same present value outcomes over the life of the asset. Apart from its similarity with historic cost accounting principles a nominal pre-tax WACC also produces cash flows that more closely matches that of lending institutions thus reducing the difference between cash inflows and outflows.
(4) The debt premium is the premium on corporate debt over equivalent gilts/bonds, which is required by financial markets to compensate for the greater risk of default on corporate debt compared with government debt. The expected cost of debt is a projection of the market cost of debt, which is not necessarily the same as the historic cost of the existing debt.

16.3. Cost of equity

(1) The cost of equity is determined using the Capital Asset Pricing Model (CAPM). This represents one of the most widely used models to estimate the expected cost of equity.

(2) Under CAPM the cost of equity is defined as the risk-free rate and the product of an individual firm’s equity beta and the Equity Risk Premium (ERP). The CAPM method estimates the rate of return as a function of the investment risk relative to the aggregate equity market risk. If the risks are the same then the expected return is equal to the expected return on equities.

(3) The formula for calculating the cost of equity is shown below:

\[ K = r_f + (\beta \times ERP) \]

Where:

- \( K \) = Cost of equity (nominal after tax)
- \( r_f \) = risk-free rate
- \( \beta \) = equity beta
- ERP = Equity Risk Premium

(4) As noted under the cost of debt above, the risk-free rate is determined using spot prices of selected long term maturity bonds appropriate to the Rwandan market (as set out under 16.5 below).
(5) The ERP represents the market premium which equity investors require in order to invest in (higher risk) equity rather than (lower risk) government bonds. The equity beta measures the non-diversifiable business risk which investors face when investing in a specific stock relative to the risk on the market portfolio.

(6) Equity beta also captures financial risk because debt holders have a prior claim on the firm’s cash flows over equity holders. Thus, all else being equal, a highly geared firm might be expected to have a higher equity beta than a lower geared firm.

16.4. Gearing

(1) Gearing refers to the percent of debt in the company’s capital structure. The proposed tariff methodology is based on the premise that a tariff application will be evaluated against a “target” rather than “actual” gearing percentage. The benefits of this approach are:

(a) It incentivises the utility to maintain an optimum capital structure, and

(b) It removes the burden on the regulator to oversee the detailed funding strategy and approaches of the utility.

(2) This position is consistent with the views of the majority of regional and international regulators.

16.5. Risk Free Rate

(1) The risk-free rate is the interest rate that an investor would require to willingly invest in an asset without any risks. The risk-free rate is a market-wide parameter and applies to all firms operating in the same country.

(2) Government bonds are widely considered to be lowest risk investment instrument in a particular market. The utilisation of government bonds to determine the risk-free rate requires two decisions. The first is to decide on the appropriate bond maturity date, in other words the outstanding time of the bond. The second is whether the observed returns should be averaged or not and, if so, over what period.
(3) Several views have been put forward in respect of bond maturity selection. In brief these are:

(a) the lifetime of the assets used in providing the regulated service on the basis that this reflects the planning horizon of investors in those assets;

(b) the duration of the regulator’s determination, or the price setting period given, that the risk-free rate will be adjusted in any subsequent review; or

(c) the bond term used to measure the market risk premium.

(4) With the exception of a few, there has been near universal adoption of the yields of long term bonds (e.g. 10 years or the nearest equivalent) by regulators in pricing decisions. This practice is not seen as contentious by most regulators. The main disadvantage of using bonds with any other maturity date is that their returns become increasingly more volatile the shorter the maturation date. This triggers unnecessary tariff adjustments when they are reviewed frequently. Other reasons for choosing a long term bond is that it reflects real interest and inflation risks better than short term bonds over the period of asset investments.

(5) It is debatable whether to use the latest traded bond yield or an average bond yield calculated over a defined period. The main motivation for calculating an average is to reduce perceived volatility. However it should be kept in mind that the best estimate of the bond yield is reflected in the most recent results. It is therefore considered acceptable to use the closing price of the most recent trading day.

(6) In view of the above the following positions are recommended:

(a) Use the yield on the (10-year) government bond (or the closest equivalent) to determine the risk free rate of Rwanda; and

(b) Use the most recent publicly available closing bond yield in estimating the risk free rate.

16.6. Debt Premium

(1) The debt premium is the additional cost of company debt over the risk free rate and is required by financial markets to compensate for the greater risk of default on
company debt compared with government debt. This means that the debt premium could be different for different electricity Licensees.

(2) If a Licensee issues bonds, then the difference between the yield of the Licensee’s bond and the risk free rate represents the debt premium. However, it is not known if the regulated entities in Rwanda issue corporate bonds at the moment. A suitable proxy therefore needs to be defined for each Licensee group. The proxy could be based on suitable regional or international references.

(3) In view of the above the following positions are recommended:

(a) Use appropriate benchmarks to estimate the Licensee’s debt premium;

16.7 Equity Beta

(1) The equity beta is a measure of the expected volatility of a particular share relative to the share market as a whole. It measures the systematic risk of the stock. That is, the risk that cannot be eliminated in a balanced and diversified portfolio. An equity beta of less than one indicates the stock has a low systematic risk relative to the market as a whole (the market average being equal to one). Conversely an equity beta of more than one indicates the stock has a high risk relative to the market.

(2) A company’s beta can be determined by using its share price and the stock market index. However, none of the regulated network entities in Rwanda are traded on a stock exchange. Thus, the equity betas for the utilities must be estimated through an alternative method.

(3) The only remaining option is to use equity beta values which have been established in overseas markets. Fortunately there are numerous regulatory decisions which may be used as precedent.

(4) It must be noted that it is not meaningful to compare equity betas between different countries. The reason for this is that the equity beta is influenced by the tax rate of the country and gearing of the company in question. International benchmarks are therefore carried out using asset (unlevered) betas.
(5) The formula to convert between asset beta and equity beta is shown below:

$$\beta_{equity} = \beta_{asset} \times (1+(1-Tc)(g/(1-g)))$$

Where:
- $\beta_{equity}$ is the equity beta
- $\beta_{asset}$ is the (unlevered) asset beta
- $Tc$ is the corporate tax rate
- $g$ is the gearing

(6) In view of the above the following positions are recommended:

(a) Use regulatory precedents to determine suitable asset betas for the regulated entities in Rwanda.

(b) Convert asset betas into equity betas using the defined conversion formula

16.8. Equity Risk Premium

(1) The Equity Risk Premium (ERP) represents the market premium which equity investors require in order to invest in (higher risk) equity rather than (lower risk) government bonds.

(2) The ERP is defined as:

$$ERP = E(R_m) - r_f$$

where:
- $ERP = $ Equity Risk Premium
- $E(R_m) = $ Return of the stock market over a specified period
- $r_f = $ risk free rate over the same specified period.

(3) In other words this means that the ERP is the difference in return that investors can expect to earn from the stock market less the risk free rate. Market return is
estimated by averaging historic stock market returns. The impact of market and other types of risk can be reduced if this is done over a reasonable period of time. The market return and risk free rate is measured over the same historic period to eliminate any distortions and possible biases.

(4) Unfortunately there are not any listed electricity companies in Rwanda that could serve as a reference.

(5) Thus, to avoid these complexities an alternative option is to determine an equity risk premium by regulatory precedent (benchmarks).

(a) In view of the above the following positions are recommended: use regulatory precedents to determine a suitable ERP for Licensees in Rwanda.

16.9. Corporate Tax Rate

(1) In order to avoid the complexity and volatility of trying to determine effective tax rates many regulators use the marginal company tax rate to estimate the impact of taxation on the Licensee. Hence, the Authority will use a tax rate which is equal to Rwanda’s fixed top corporate tax rate.
17. **Annexure B: Connection Charges**

(1) The connection charge is a *Customer*-specific charge to new *Customers* to cover expenses incurred to establish network infrastructure for the benefit of the new *Customer*. This connection charge is generally applicable to both *Generators* and *Customers* using the network system.

(2) The principal requirement that each *Customer* pay for the costs that he or she directly induces on the grid (e.g. his own connection-line) is well justified and provides a suitable signal of the cost that this *Customer* incurs by connecting to the network.

(3) Within this context, various approaches to connection charging are possible. These are grouped into the following categories:

   (a) No connection charges
   (b) Shallow connection charges.
   (c) Semi-deep connection charges
   (d) Deep connection charges.

(4) If no explicit connection charges are levied, the costs associated with new connections may be recovered via the network UOS charge.

(5) Shallow connection charges relate only to the immediate costs incurred associated with infrastructure in close proximity of the *Generator/load*, such as the construction of a line and installation of a transformer to serve the site. By contrast, deep connection charges include any additional network strengthening that may be required upstream (i.e. “deeper” in the rest of the network system) to maintain the stability of the network with the new load/generation connected.

(6) Shallow connection charges are relatively straightforward to determine, as the assets involved are usually easily identifiable and attributable to a specific *Customer*. However, the implementation of deep connection charges is not trivial and is subject to dispute as to whether the “deep” component of the cost is entirely due to the new
connection. The “deep” portion of the connection charge may arise from investments in network strengthening in parts of the network that may be far from the new load or Generator. It can be difficult to assess whether these investments are truly additional or whether they would have occurred anyway.

(7) It may also be argued that the investment requirement may have been accelerated by the new network user, and the relevant charge then becomes the cost of this acceleration (i.e. the cost of capital over the time which the investment has been bought forward). In this case, the timing of the investment without the new network user can be subject to uncertainty, and hence dispute.

(8) The connection charge approach is further complicated if the infrastructure is shared at a later point in time. In certain instances, it may be necessary to build a new line for a new Customer, but there is a possibility that other new Customers will be connected in the same area. Equitable cost allocation and the advantages of scale economies make the application of connection charges problematic. It may, for example, be more efficient in the long run to build a line with a larger capacity than what is needed to serve the first new Customer. The first new Customer may be required to pay only for the part of the line required to meet its specific needs. This would imply that all other existing users (from whom the remaining costs need to be recovered) face increased network tariffs triggered by the newcomer’s need for network infrastructure.

(9) Alternatively, the new Customer may be required to pay the full costs of the new (over-sized) line. But this has some obvious problems. One of them is the disincentive to invest arising from higher network costs. In addition, there is a question of how to make the tariffs “fair” between the first entrant and the later newcomers. There is no single best solution to this challenge. The best choice depends on the number of possible newcomers, the magnitude of the scale effects, willingness to pay etc.

(10) It is important to recognize that there is no “correct” approach. The most appropriate approach depends on weightings policy makers place on the various
tariff principles. The following sections discuss the advantages and disadvantages of the various approaches to connection charges in more detail.

17.1. No Connection Charges

(1) If Customers are not required to pay connection charges then all the capital cost needed to connect a Customer is built into other network charges. This means that all connection costs are borne by all the consumers. This approach masks the direct costs of connection and removes the economic signal to producers and consumers on where they should locate themselves to provide optimal benefit to the network. Although the approach is easy to implement, it is not cost-reflective and not particularly fair. Most regulators consider this to be discriminatory because existing users would need to meet significant costs caused by new users for new infrastructure, from which the existing users would derive no benefit.

17.2. Shallow Connection Charges

(1) In this approach, a Customer pays for only those assets in the immediate vicinity of the point of connection and normally only assets that are not shared with other Customers. This definition may include assets which, at the time of construction, are to be shared among a clearly identified group of connected parties. This is also referred to as dedicated network infrastructure.

(2) These costs often relate simply to the assets required to make a physical connection from the existing system to the Customer's Apparatus. Any deeper reinforcement costs are regarded as resulting from demand or generation growth and recovered from all system users through network use of system charges.

(3) Shallow charging tends to minimize the upfront payment required to connect to the system, and encourages the development of demand and generation connections. Another key advantage is that the approach is simple and avoids complex arguments about who benefits from network strengthening. “Shallow” charging is also advantageous in that the new user can readily identify the connection assets and hence there is transparency as to the value being provided to the new user.
Furthermore, the utility can readily identify and cost the relevant assets without incurring any significant administrative overhead.

(4) An obvious disadvantage is that there will be some users (notably large remotely located new users relative to the existing network) who impose a heavy cost burden on the system. In such cases extensive work may be required to the network, not just in the geographic vicinity of the new user but possibly on the wider network. If “shallow” charging is applied in such instances then existing users would be required to meet the costs of such extensive works, through higher network charges. In effect large new users would be subsidized by existing users, which may understandably be considered inequitable. This approach is only partially cost-reflective and therefore does not give locational signals to new users of the system on the most advantageous points of connection.

17.3. Deep Connection Charges

(1) In this approach Customers pay for all system developments incurred as a result of their connection. In some cases these costs may be incurred for infrastructure that is remote from the new connection site. Examples of this include a need for reinforcement at a higher voltage level than that of the connection as a direct result of the connection, or where Apparatus has to be upgraded to, for example, cater for increased fault levels. As a result of including these factors, deep connection charges tend to be higher than those under a shallow connection policy.

(2) Deep charging has the advantage of giving strong locational signals for new connections, although many Customers, especially domestic Customers, would arguably be unresponsive to such locational signals. Deep charges for connection tend to reduce the level of other network use-of-system charges for all users (not just the new connecting Customer).

(3) The main drawback of a deep connection charging policy is the contentious nature of such charges. Further disadvantages include problems caused by the significant and "lumpy" nature of reinforcement that can be driven by a small increase in connection capacity. For example, if a new connection drives the loading of the
system beyond its existing limits, the next available level of increased capability may be at a much higher value of loading, with attendant high costs to be met, and significant redundant capacity which is not immediately required by new or existing users. This can present immediate difficulties of acceptability for the new user seeking the increased capacity and subsequent problems as additional new or existing users take up the new level of "spare" capacity. As such, steps are sometimes taken to redress the "free-rider" problem caused by users gaining benefits already paid for by a single, earlier Customer. This is usually done by transferring credits to the first-comer from payments made by later Customers, but can be complex and problematic.

(4) Whilst there is an economic rationale for deep charging based on a complete allocation of all additional costs, the estimation of deep charges would require the utility to carry out sophisticated mathematical analysis of its network. In the process, the utility would need to make several critical assumptions, which are subject to challenge.

(5) In summary, the approach of deep connection charges has some major drawbacks:

(a) Difficult to apply properly in practice;
(b) Potentially discriminatory, notably between existing Generators/Customers and new entrants. While a ‘deep’ connection charging policy could arguably be applied consistently to all new connections, it would be impossible to execute consistently for all existing connections, given the historic nature of the network system. Thus it would be impossible to determine today, for each existing connection to the system, what remote reinforcement costs were necessary in the past to accommodate those connections, and hence what an appropriate connection charge should be in each case. A ‘deep’ connection charging policy would therefore almost certainly discriminate between existing and new users of the system;
(c) Potentially inequitable - resulting in outcomes that either discriminate against first or subsequent new connections; and
(d) Not guaranteed to produce cost reflective charges, in the sense that remote generation reinforcement could be argued to be of benefit to a greater number
of users of the network system, since this results in a more secure and reliable system than would otherwise have been the case. Under a ‘deep’ connection charging policy, a new user would be subsidizing another user’s network improvements.

17.4. Recommendation

(1) On grounds of complexity and fairness (non-discrimination), the vast majority of countries have adopted a “shallow” or “semi deep” approach to the determination of connection charges. The “semi-deep” approach is also termed “shallowish” and allows greater cost-reflectivity than shallow charging. This approach is also less contentious than a deep charging methodology.

(2) It is recommended that this approach be adopted for Rwanda.

(3) See Network Code for a discussion on the implementation of network Connection Agreements.
18. **Annexure C: Capacity Measurement**

(1) Given the significance of the network capacity charges, it is important to note that there are several ways to measure demand/injection capacity. This is an important element of the network charges, which are both based on payments of FRW/kVA/month or FRW/kW/month. The significance of these approaches is that there is a wide variance in the measured kVA and kW which would understandably lead to fundamentally different charges levied.

### 18.1. Non-coincident peak

(1) The non-coincident peak demand/injection is the Customer's maximum energy demand/injection during any stated period. Customers who use/inject quantities of electricity may pay a monthly demand charge based on their individual maximum electric demand/injection during each month. This maximum demand/injection in the ESI can also be called a Customer's monthly non-coincident peak demand/injection.

### 18.2. Coincident peak

(1) This is the demand of individual Customers (or sub-systems) that coincides in time with the peak demand of the whole IPS or of a particular TransCo/DisCo.

(2) It is important to note that that charging for the coincident peak creates a number of potential issues including the fact that Customers do not know for certain when the monthly system peak will occur and hence when their respective peak will be.

(3) Another concern with this approach is that Customers will only find out after the fact when the system peak occurred. This makes peak demand management near impossible for Customers and therefore undermines efforts to control costs through peak demand reduction. This removes transparency and cost control, thereby undermining the principle of having charges that encourage the efficient use of electricity.
18.3. **Sum of 12-month coincident peak**

(1) As the name indicates, this approach adds the coincident peak value per Customer over a 12-month period. This method is usually used when the monthly peaks lie within a narrow range; i.e. when the annual load shape is not spike.

18.4. **Multiple coincident peak**

(1) This approach uses demand/injection in certain hours to determine the measured capacity value. The number of hours may be determined judgmentally; e.g., the 10 or 20 hours in the year with the highest system demands, or by applying specified criteria. Criteria for determining which hours to use include:

a. All hours of the year with demands within 5% or 10% of the system’s peak demand

b. All hours of the year in which a specified reliability index (loss of load probability, loss of load hours, expected energy not served (EENS), or reserve margin) passes an established threshold value. This may result in a fairly large number of hours being included in the development of the measured demand value.

18.5. **All peak and/or standard hours**

(1) This approach combines the multiple coincident peak approach with the non-coincident peak approach to measure demand/injection during peak and/or standard hours (or any grouping of hours). The grouped hours would usually represent those hours that are critical from the utility’s network planning perspective.

18.6. **Proposed capacity measurement**

(1) Based on the options available and the requirement for simplicity and transparency without undermining economic efficiency, it is proposed that network UOS capacity charges be made on the basis of non-coincident peak demand within a defined system peak demand period (that coincides with the peak demand period for
generation service charges). To the extent that Metering arrangements for particular Customers are unsuitable for such charges, it is proposed that non-coincident peak demand within the defined system peak demand period is imputed by the retailer based on Customer characteristics.

(2) UOS capacity charges need to take account of poor power factors and associated reactive power consumption. This may be handled implicitly via a single UOS capacity charge expressed in FRW/kVA/month.

(3) We also note that the practice in some countries is that a minimum charge is levied on Customers typically based on billing demand e.g. the minimum amount in any monthly billing period shall not be less than x% of the maximum amount payable in respect of billing demand charges payable in the preceding 12 months. This approach in effect improves revenue stability.