THE KENYA ELECTRICITY GRID CODE

PART 1: KENYA NATIONAL TRANSMISSION GRID CODE (KNTGC)

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CONTENTS

1 PREAMBLE

1.1 INTRODUCTION

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 electrical system in a manner that will ensure reliable, efficient and safe operation.

This Preamble provides the rationale for the development of the*Kenya National Transmission Grid-Code (KNTGC)* and summarises the provisions of the *KNTGC*. The *KNTGC* underwent a rigorous approval process involving the *Energy and Petroleum Regulatory Authority*, the *Ministry of Energy*, the *Attorney General* and *Parliament*.

The objective of the *KNTGC* is to improve the ability of Kenya's power system to be planned and operated safely, reliably, efficiently, and economically, in a transparent and non-discriminatory manner, while multiple independent parties use the power system. The *KNTGC* provides a framework of rules and regulations under which *Users* must operate and coordinate with each other and with the operators of the power system. The *KNTGC* is intended to establish the reciprocal obligations of *Users* of the *Kenya National Transmission System (KNTS*) and operation of the *Eastern African Power Pool*.

The development of the *KNTGC* took into account the *Eastern Africa Power Pool* and *East African Community Interconnection Code (EAPP IC)*. The *EAPP IC* imposes certain minimum requirements on the Member Countries of the *EAPP*. Thus the *EAPP IC* plays an important role in the *KNTGC*. This *KNTGC* follows to the extent possible the organisation and formatting of the *EAPP IC*.

Other national grid codes were considered and reviewed in addition to the *EAPP IC*, including the South African Grid Code (2012), the South African Grid Connection Code for Renewable Power Plants (2012), the Namibian Grid Code (2005), the Indian Electricity Grid Code (2010), the Zambian Grid Code (2006) and the Rwanda Grid Code (2012).

Addressing exclusively wind power, the Australian Energy Market Operator (AEMO) report "Wind Integration: International Experience WP2: Review of Grid Codes 2ndOctober 2011" provided a review of Grid Codes from the United Kingdom, Germany, Denmark, Spain, Texas, Alberta, Hydro Quebec, Ontario Independent Electricity System Operator (IESO), and the European Network of Transmission System Operators for Electricity (ENTSO-E). This review was helpful in preparing *Renewable Power Plant* (*RPP*) Chapter of the KNTGC.

1.2 STRUCTURE OF THE KNTGC

The *EAPP IC* and the *KNTGC* each place obligations on the *Energy and Petroleum Regulatory Authority*, the *System Operator* and *Users.* In the chapters of the *KNTGC*, the *EAPP* requirements are listed first, followed by requirements specific to the *KNTS*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

The *KNTGC* is divided into the following chapters:

1.2.1 Preamble

This Preamble summarises the provisions of the *KNTGC*.

1.2.2 Glossary and Definitions

The Glossary and Definitions contains a glossary of terms and a list of abbreviations and units used in the *KNTGC.* Defined terms are italicised and capitalised throughout the *KNTGC and* hold the meanings as defined. However, if a term is not capitalised or italicised, it shall still hold the definition as provided in the Glossary.

1.2.3 General Conditions

The General Conditions (GC) set out the over-riding principles to be used in the operation of the *KNTS* and form the basis for the actions of a reasonable and prudent operator should specific events not be covered by the relevant chapter. The GC describes the provisions necessary for the overall administration and review of the various aspects of the *KNTGC*. The GC also deal with those aspects of the *KNTGC* not covered in other chapters, including the resolution of disputes, bilateral agreements, confidentiality, non-compliance and the revision of the *KNTGC* through the *Kenya National Transmission Grid Code Review Committee*.

1.2.4 Governance Chapter

The Governance Chapter summarises the main documents and organisations that provide the authority governing the planning, construction, and operation of the *KNTS*.

1.2.5 Planning Chapter

The Planning Chapters pecifies the minimum technical and design criteria, principles, and procedures:

(a) To be used within Kenya in the medium and long term planning and development of the *KNTS*;

(b) To be taken into account by *Member Utilities* on a coordinated basis, and

(c) To specify the planning data required to be exchanged by *Member Utilities* and the *EAPP* Sub-Committee on Planning to enable the *EAPP* Interconnected *Transmission System* to be planned in accordance with planning standards.

1.2.6 Connections Chapter

The Connections Chapter specifies the minimum design, technical, and operational criteria of Plant and Apparatus which must be complied with by both *Users* and *System Operator* at *Connection Points* in order to maintain secure and stable operation of the *KNTS*.

1.2.7 Renewable Power Plant Chapter

The *Renewable Power Plant* Chapter sets out the requirements for renewable power plants, especially wind and solar power plants, so that they will be able to contribute to the stability of the *KNTS*.

1.2.8 Operations Chapters

The Operations Chapters (OC) set out the data exchange between and responsibilities of the *SO*, the other T*SOs,* and the *EAPP* in operating the *EAPP Interconnected Transmission System*. The six OCs (OC 1 through OC 6, Chapters 8 through 13) deal with the criteria and procedures which will be required to facilitate efficient, safe, reliable and coordinated system operation of the *KNTS,* other *National Systems,* and the *EAPP Interconnected Transmission System*. They include chapters addressing Operational Planning, Operational Security, Emergency Operations, Incident Reporting, Demand Control, and System Tests.

1.2.8.1 Operational Planning

Operations Chapter 1 summarises *Outage* requirements for generation and transmission facilities and other factors likely to affect the operation of the *KNTS*, which shall be coordinated between the *SO*, other *TSOs*, and the *EAPP Coordination Centre (EAPP CC)* for a period of three (3) years ahead down to real time. In accordance with the terms of Chapter 5 (Planning), OC 1 also requires the *SO*, other *TSOs* and the *EAPP Sub-Committee on Planning* to produce a *Power Balance Statement* and a *Transmission System Capability Statement* on an annual basis for the succeeding ten (10) years. It also sets out refinements of the planning process to account for nearer-term characteristics.

1.2.8.2 Operational Security

Operations Chapter 2 specifies the technical requirements and standards for the operational security of the *KNTS*, the *National Systems* of other *Member Countries*, and the *EAPP Interconnected Transmission System* as they relate to the following issues:

(a) N-1 *Contingency* criterion;

(b) Interchange scheduling;

(c) Operating reserves for control of system frequency and interchange with other *Control Areas* or *External Systems*;

(d) Voltage control;

(e) Fault level control;

(f) Protection coordination, and

(g) Remedial *Action Schemes (RAS).*

1.2.8.3 Emergency Operations

Operations Chapter 3 sets requirements to ensure that the *SO*, other *TSOs*, and the *EAPP CC:*

(a) Are able to identify insecure operating conditions on the *EAPP Interconnected Transmission System*;

(b) Have procedures and plans in place to manage emergency conditions;

(c) Have comprehensive *Contingency* plans in place for the restoration of supplies in the shortest possible time using the most effective means.

1.2.8.4 Incident Reporting

Operations Chapter 4 sets out the requirements for reporting significant incidents that have caused, or could have caused, damage to system equipment or operation of the *KNTS*, other *National Systems*, and or the *EAPP Interconnected Transmission System* outside the Operational Security Standards.

This chapter also sets out the procedures for the joint investigation of significant incidents and for the technical audit of the *SO* and other *TSOs* procedures and Plant and Apparatus connected to, or forming part of, the *EAPP Interconnected Transmission System*.

1.2.8.5 Demand Control

Operations Chapter 5 sets out the provisions to be made by the *SO,* in cooperation with the *EAPP CC*, to permit reductions in demand in the event of insufficient generation capacity being available to meet demand or in the event of breakdown or thermal overloading of any part of the *KNTS* or the *EAPP*

Interconnected Transmission System leading to the possibility of unacceptable frequency or voltage conditions.

1.2.8.6 System Tests

Operations Chapter 6 sets out the arrangements, data exchange, and and procedures across the *EAPP Interconnected Transmission System* for *System Tests* or operational tests including *Black Start* tests and *Power Island* tests. *System Tests* are those tests, which involve either a simulated or a controlled application of irregular, unusual, or extreme conditions on the *EAPP Interconnected Transmission System*. In addition, they include Commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out by a *User* and which may have a significant impact upon the *EAPP Interconnected Transmission System*.

1.2.9 Interchange Scheduling and Balancing Chapters (Three Chapters)

The Interchange Scheduling and Balancing Chapters (ISBC) set out the procedures for the scheduling, coordination and balancing of power transfers across the *EAPP Interconnected Transmission System*. The ISBC is divided into Chapters 14, 15, and 16 of the *KNTGC:* ISBC 1 Interchange Scheduling, ISBC 2 Balancing and Frequency Control, and ISBC 3 Ancillary Services.

1.2.9.1 Interchange Scheduling

ISBC 1 Interchange Scheduling deals with the following aspects of the scheduling process:

(a) Determination of the *Net Transmission Capability (NTC)* between *Neighbouring Control Areas* and or *External Systems* over the *Operational Planning* timescales;

(b) Publication of *NTC* values to enable the *SO*, other *TSOs*, and *Users* to evaluate possible energy interchanges;

(c) Allocation of *NTC* to the *SO*, other *TSOs*,and or *External Systems* in accordance with pre-determined rules and the issue of *Interchange Schedules.*

1.2.9.2 Balancing and Frequency Control

ISBC 2 Balancing and Frequency Control sets out the procedure that the *SO* and other *TSOs* will use to direct frequency control. The frequency of the *EAPP Interconnected Transmission System* will be controlled by:

(a) Automatic response from synchronised *Generating Plants*;

(b) The dispatch of *Generating Plants* including *Automatic Generation Control (AGC)*;

(c) Response from interconnections with *External Systems*, and

(d) Demand control.

1.2.9.3 Ancillary Services

ISBC Chapter 3 Ancillary Services sets requirements for the provision of *Ancillary Services* to ensure that the *SO* and other *TSOs* meet the obligations and responsibilities under the *EAPP IC* for a safe, secure, and reliable operation of the *EAPP Interconnected Transmission System*.

The operation of the *KNTS*, other *National Systems, and the *EAPP Interconnected Transmission System* requires the provision by the *SO* and other *TSOs* of the following *Ancillary Services* grouped into three major categories:

(a) Frequency Control;

(b) Network Control, and
(c) System Restart Capability.

The above *Ancillary Services* are the traditional mechanisms to provide the required capability in relation to:

(a) Operating Reserves;
(b) Demand Control;
(c) Voltage Control;
(d) Power flow control;
(e) Stability control, and
(f) Black-Start.

1.2.10 Kenya Metering Chapter

The Kenya Metering Chapter (KMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each *Connection Point* of a *User* with the *KNTS*. The KMC also specifies the associated data collection equipment and the related metering procedures required for the operation of the *KNTS*.

1.2.11 Interconnection Metering Chapter

The Interconnection Metering Chapter (IMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each point of interchange of energy between *Control Areas*. The IMC also specifies the associated Data Collection and the related metering procedures required for the operation of the *EAPP Interconnected Transmission System*.

1.2.12 Data Exchange Chapter

The Data Exchange Chapter (DEC) defines the data to be exchanged between the *SO*, other *TSOs*, and the *EAPP* Sub-Committees on Planning and Operations for the purpose of the modelling and analysis of steady-state and dynamic conditions for the *EAPP Interconnected Transmission System.* The DEC sets out the information flows required between the *SO*, other *TSOs,* and the *EAPP Sub-Committees on Planning and Operations* to produce *EAPP* system models for the various processes that require system studies to be undertaken. These processes include those associated with System Planning as set out in the Planning Chapter, including the preparation of the *Transmission System Capability Statement*, and with *Operational Planning* as set out in Operations Chapter1.

1.2.13 Information Exchange Chapter

The Information Exchange Chapter (IEC) defines the reciprocal obligations of parties with regard to the provision of information for the implementation of the *KNTGC*. The information requirements, as defined for the *Transmission Network Service Provider, the SO, the Authority, and Users*, are necessary to ensure non-discriminatory access to *the Kenya National Transmission System* and the safe, reliable provision of transmission services. The information requirements are divided into planning information, operational information and post-dispatch information.

1.2.14 Cyber Security Chapter

Cyber Security can be defined as the protection required to ensure confidentiality, integrity, and availability of the electronic communication system. With the two-way flow of electricity and information, the management and protection of the electrical communication system that includes information technology and telecommunication infrastructure has become critical. The Cyber Security Chapter sets out requiremens in the following areas:

(a) Development of information security management controls and procedures;
(b) Cyber security systems;
(c) Access management for systems; and
(d) Building defence against threats through training, awareness and monitoring.

1.2.15 System Operator Training Chapter

The System Operator Training Chapter sets out the responsibilities and the minimum acceptable requirements for the development and implementation of *System Operator* Training and authorisation programmes. This chapter requires that *System Operator*s within Kenya and throughout *EAPP* and *EAC* are provided with continuous and coordinated operational training in order to promote the reliability and security of the *EAPP Interconnected Transmission System.*

1.3 SCOPE OF THE KNTGC

The *KNTGC* establishes the technical aspects of the planning, connection, operation, and use of the *Kenya National Transmission System* and the relationships between the *System Operator (SO)*, *Transmission Network Service Provider(s) (TNSPs)*, *Generation Licensees*, and other *Users* of the *Kenya National Transmission System*.

The *KNTGC* shall be read in conjunction with the relevant legislation, including the *Energy Act* and the Regulations thereunder and any applicable amendments related to the administrative authority for the *KNTGC*. These legislative instruments shall be used in conjunction with the *Licences* issued to *Users* and and the applicable codes and regulations adopted by the *Authority* and the *Ministry of Energy*. All Licences issued after enactment of the *KNTGC* shall include the obligation of *Parties* to comply with the *KNTGC* requirements.

2 GLOSSARY AND DEFINITIONS

2.1 INTRODUCTION

This chapter contains a glossary of terms and a list of abbreviations and units used in the *KNTGC*.

2.2 GLOSSARY

Table 2-1 provides a summary of the terms and definitions used in the *KNTGC*.

Table 2-1 Glossary and Definitions

Word or Phrase	Definition
Active Energy	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.
Act	The Energy Act, No 1 of 2019
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.
Active Power Control	The automatic change in Active Power output from a Wind Turbine or Solar Power Generating Plant in response to an Active Power Control Set-point received from the Transmission Licensee or Distribution Licensee.
Active Power Control Set-point	The maximum amount of Active Power in MW, set by the Transmission Licensee or Distribution Licensee, that the Wind Turbine or Solar Power Generating Plant is permitted to export.
Actual Metering Point (AMP)	The physical point at which the flow of electricity is measured and where the Interchange Metering is installed. The AMP may be different from the Defined Metering Point subject to the approval of the EAPP CC. In these cases, the accuracy requirements in Section 18.1.9 shall apply at the Defined Metering Point.
Agent	A person appointed by an entity to perform any of its functions or act on its behalf.
Agency	Nuclear Power and Energy Agency established under the Act.
Ancillary Services	The services that are essential to the management of power system security, facilitate orderly trading in electricity and ensure that electricity supplies are of acceptable quality and, Without limitation, these services may include: (a) the provision of sufficient regulating capability to meet fluctuations in load occurring within a scheduling interval;

Word or Phrase	Definition
	(b) the provision of sufficient contingency capacity reserve to maintain power system frequency in the event of network or generation outages; (c) the provision of reactive power support to guard against power system failure through voltage collapse; and (d) the provision of black start capability to allow restoration of power system operation after a complete failure of the power system or part of the power system.
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.
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.
Attorney General	The Attorney-General appointed under Article 156 of the Constitution of Kenya, 2010.
Automatic Generation Control (AGC)	Equipment that automatically adjusts a Control Area's generation to maintain its interchange schedule plus its share of frequency regulation.
Automatic Load Shedding Scheme	A load-shedding scheme utilised by the System Operator or another TSO to prevent frequency collapse and to restore the balance between generation output and demand.
Automatic Voltage Regulator (AVR)	The continuously acting automatic equipment controlling the terminal voltage of a Synchronous Generating Plant 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.
Authority	The Energy and Petroleum Regulatory Authority established under the Act.
Black Start	The procedure necessary for recovery of the Kenya National Transmission System from Total Shutdown or Partial Shutdown.
Black Start Capability	Ability in respect of a Generating Plant, for at least one of its units to Start-Up from Shutdown without an external electrical power supply and to energise a part of the Kenya National Transmission System and be Synchronised to the System upon instruction from the Transmission Licensee or Distribution Licensee.

Word or Phrase	Definition
Chairperson	The person duly appointed by the Authority to be Chairperson of the Kenya National Transmission Grid Code Review Committee, or the person appointed by the Chairperson to be his alternate, or the person appointed to act as Chairperson of a meeting of the Kenyan National Transmission Grid Code Review Committee in the absence of the Chairperson or his alternate.
Check Meter	A Meter nominated to provide electrical energy measurements at a Defined Metering Point for verification or substitution of the Main Meter.
Conductor	An electrical medium connected or arranged to be electrically connected to a system purposefully meant for transportation of electrical energy from one point to another.
Confidential Information	Information which is or has been provided under or, in connection with the Kenya National Transmission Grid Code and which is stated under the Code or by the Authority to be Confidential Information.
Connection	Physical link to or through a transmission/distribution network that will allow the supply of electricity between electrical systems.
Connection Agreement	A bilateral agreement made between the System Operator or a TNSP and a User setting out the terms and conditions relating to the use of the Connection Point and other specific provisions in relation to that connection.
Connection Charge	The costs incurred in the developent of the infrastructure to connect the customer’s premises
Connection Point	The physical point at which a User is connected to the Kenya National Transmission System; the electrical node on a transmission system where a User’s assets are physically connected to the TNSP’s assets.
Contingency	An unexpected incident, failure or Outage of an interconnected system component, such as a Generating Plant, 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.
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 to the Kenya National Transmission System.
Control Area Operator	The System Operator or another TSO responsible for operating, monitoring, and ensuring interchange scheduling of its Control Area.

Word or Phrase	Definition
Control Centre	A physical location from which an SO or TSO exercises control over its transmission area.
Current Transformer (CT)	A transformer for use with meters and/or protection devices in which the current in the secondary winding is, within prescribed error limits, proportional to and in phase with the current in the primary winding.
Customer	A person obtaining or entitled to obtain electricity services from a Licensee.
Data Collection System (DCS)	A computer based system that collects or receives data on a routine basis from Metering Equipment.
Defined Metering Point (DMP)	The DMP is at the Interchange Point within a Control Area and means the physical location at which overall accuracy requirements as defined in the IMC are to be met. The DMP shall be defined in the relevant Connection Agreement. Each single circuit interconnection between Control Areas will have two DMPs, one in each Control Area.
Derogation	A waiver issued by the Authority to suspend a Transmission Licensee's, Distribution Licensee's, or User's obligations to implement or comply with a provision of the KNTGC.
Dispatchable Resource	(1) A generation plant that can guarantee firm capacity and is capable of being turned on or off or can adjust power output upon request by the SO; (2) 2) A customer participating as a demand side resource that can comply with SO instructions to reduce electricity usage.
Dispute	Any difference between the Authority and any Transmission Licensee or Distribution Licensee or User or between the Parties in connection with, or arising out of, the interpretation, implementation or breach of any provision of the KNTGC.
Dispute Notice	A written notice issued by either Party to a Dispute outlining the matter of such Dispute.
Distribution Licence	As defined in the Act.
Distribution Licensee	A person granted a licence by the Authority for the ownership and/or operation and maintenanceof a distribution system in Kenya.
Distribution Network	A power delivery system that delivers electric power from electrical substation at sub-transmission level to the end users.
Distribution System	A system, works, plant, equipment or service for the delivery or supply of energy directly to the consumers, but does not include a power plant or transmission line.

Word or Phrase	Definition
EAPP Coordination Centre (EAPP CC)	Body established under the guidance of the EAPP Sub-Committee on Operation responsible for the collection of technical and commercial information.
EAPP Independent Regulatory Board	Board consisting of nominees of national regulatory boards in the EAPP countries that is the regulatory body governing the EAPP IC.
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.
EAPP Sub-Committee on Planning	The body under the direction of EAPP Steering Committee responsible for the coordination of Master Plans and development programs of EAPP Member utilities.
Eastern African Power Pool	A regional intergovernmental body based in Addis Ababa, Ethiopia. Its mission is the pooling of electrical energy resources in a coordinated and optimized manner to provide affordable, sustainable and reliable electricity in the region.
Eastern Africa Power Pool and East African Community Interconnection Code (EAPP IC)	The Interconnection Code that sets down the technical rules for the coordinated planning and operation of the EAPP.
Electric Supply Line	As per the Act
Electrical Energy	As per the Act
Electrical Plant	As per the Act
Environmental, Health and Safety Obligations	Obligations placed on Licensees by the Act and by other applicable statutes and regulations in Kenya
End-user	A Customer of the KNTS that contracts for purchase of electrical energy for his own use, not for delivery or supply to another person
Energy	As per the Act
Tribunal	The Energy and Petroleum Tribunal established under the Act.
Expected Unserved Energy	A forecast of the aggregate amount by which the demand for electricity exceeds the supply of electricity.
External System	Any electric system outside EAPP that interconnects to the EAPP Interconnected Transmission System.

Word or Phrase	Definition
Financial Year	The period commencing on 1st July in one calendar year and terminating on 30th June in the following calendar year.
Force Majeure	Causes beyond the reasonable control of and without the fault or negligence of the Party claiming Force Majeure. It shall include failure or interruption of the delivery of electric power due to causes beyond that Party's control, including Acts of God, epidemic, pandemic, wars, sabotage, riots, hurricanes and other actions of the elements, civil disturbances and strikes.
Generating Plant	Any electric power facility or Apparatus delivering electrical energy to the Kenya National Transmission System. Generating Plants shall be understood to be comprised of one or more units which make up the total plant capacity and may be individually controllable.
Generating Unit	Any electric power Generating Plant or Apparatus delivering electrical energy to the Transmission System. This is the term used by the EAPP IC for a Generating Plant.
Generation Licence	A licence authorising a person to generate electrical energy.
Generation Licensee	An entity licensed by the Authority to own, operate and maintain generation assets and generate electricity within the Kenya National Transmission System.
Government	The Government of of the Republic of Kenya.
Governor	Automatic control system which maintains the desired system frequency by adjusting the mechanical power output of the turbine.
Grid	The network of transmission systems, distribution systems and connection points for the movement and supply of electrical energy from Generating Plants to Customers.
Grid Code Revision Register	A Register of all revisions to the Kenya National Transmission Grid Code as set out in Chapter 4 (Governance).
Inadvertent Deviation	Difference between net actual energy flow and net scheduled energy flow into or out of the Control Area.
Independent Expert	A well-qualified person with broad proven experience who provides advice to the Kenya National Transmission Grid Code Review Committee on issues concerning the Grid Code.
Independent Regulatory Board	Regulatory body of EAPP which consists of nominees of national regulatory boards of EAPP Member Countries with the responsibilities provided for in the IG-MoU.
Induction Generator	A type of alternating current (AC) electrical generator that uses the principles of induction motors to produce power.

Word or Phrase	Definition
Induction Motor	An AC electric motor in which the electric current in the rotor needed to produce torque is obtained by electromagnetic induction from the magnetic field of the stator winding.
Installation	As defined in the Act.
Interchange Point (IP)	A location where power flows from one Control Area to another Control Area.
Interchange Metering	Metering Equipment at Interchange Points normally consisting of continuous MW metering for AGC purposes and MWh metering for the accounting of Inadvertent Deviations from Interchange Schedules.
Interconnection Agreement	An agreement made between the System Operator and a Transmission System Operator of another EAPP Member Country, relating to the transfer of power and or Active and or Reactive Energy and or Ancillary Services between their respective electric systems.
Inter-Governmental Memorandum of Understanding (IG-MoU)	A binding agreement that enabled the establishment of EAPP. The document covers issues such as the members, obligations, organisational structure, resources, arbitration, and enforcement of EAPP.
Inter-Utility Memorandum of Understanding (IU-MoU)	A binding agreement between utilities of Member Countries of EAPP which defines the fundamental principles for the management and operation of the EAPP.
Kenya Bureau of Standards (KS) IEC	The set of IEC standards approved and adopted by the Kenya Bureau of Standards.
Kenya Gazette	The Kenya Gazette published by authority of the Government of Kenya, and includes any supplement thereto.
Kenya National Transmission System (KNTS)	The electricity transmission system of Kenya including all Users connected to that system
Kenya National Transmission Grid Code Review Committee	The Committee established in accordance with Chapter 4 (Governance) of this Code and charged with providing recommendations to the Authority on the review and revision of the KNTGC. The Kenya National Transmission Grid Code Review Committee shall be governed by the provisions set out in Section 4.5 of the KNTGC.
Licence	As defined in the Act.
Licensee	As defined in the Act.
Main Meter	The primary meter nominated to provide electrical energy measurements at a defined Metering Point.
Maintenance Plan	Coordinated list of all planned transmission and generation Outages.

Word or Phrase	Definition
Maintenance Outage	Scheduled removal from service, in whole or in part of a Generating Plant or transmission facility in order to perform necessary repairs on specific components of the facility.
Member Country	A country under EAPP whose government has signed the IG-MoU.
Member Utility	Public or concessionary utility in charge of power generation, transmission, and/or distribution and who has fulfilled membership conditions of the EAPP (which include signing the IU-MoU).
Meter	As defined in the Act.
Meter Information Register (MIR)	A system which uniquely identifies the Meter and Users associated with the Meter and contain pertinent data relating to the Meter.
Metering Equipment	Meters, time-switches, measurement transformers, metering protection and isolation equipment, circuitry and their associated data storage and data communications equipment and wiring which are part of the Active Energy and Reactive Energy measuring equipment at or relating to the Defined Metering Point.
Ministry of Energy	The Ministry of the Government of the Republic of Kenya responsible for matters related to energy.
National System	The electricity transmission system of an EAPP Member Country including all Users connected to that system. For the purposes of the KNTGC, refers to the Kenya National Transmission System.
Neighbouring System	Any system or Control Area either directly interconnected with or electrically close to the EAPP Interconnected Transmission System so as to be significantly affected by it.
Operating Margins	Generating capability in MW above firm System Demand available to provide for regulation, load-forecasting error, equipment forced and scheduled outage.
Operational Effect	An effect which causes the Kenya National Transmission System to operate (or be at a materially increased risk of operating) differently to the way in which it would or may have normally operated in the absence of such effect.
Operational Plan	The plan issued each day containing details of all Outages of Generating Plants and Transmission equipment, details of anticipated transfers, transmission constraints, Contingency plans and any other relevant information.
Outage	Disconnection or separation, planned or unplanned, of one or more elements of the Kenya National Transmission System.
Partial Shutdown	The same as a Total Shutdown except that all generation has ceased in a separate part of the Kenya National Transmission System and there is

Word or Phrase	Definition
	no supply from External Systems or other parts of the Kenya National Transmission System and therefore that part of the interconnected system is Shutdown.
Parliament	The Parliament of the Republic of Kenya is the bicameral legislature of Kenya, consisting of two houses: the Senate and the National Assembly.
Party	In a general sense refers to any person or entity with the specific meaning ascribed in the related provision of the Kenya National Transmission Grid Code.
Person	As defined in the Act.
Photovoltaic Solar Plant	A plant that generates electricity directly from sunlight
Planned Outage	An Outage for which at least ten (10) days notice has been given to allow the Outage to be planned in accordance with the Outage Planning Process as described in Chapter 8 (Operations Code No.1- Operations Planning).
Planning and Development Organisations	Those entities that have responsibility for the planning and development of transmission, distribution, and generation in Kenya. These entities include but are not limited to the SO, the Authority, Transmission Licensees, Distribution Licensees, and Generation Licensees.
Plant	Fixed or movable equipment used in the generation and/or supply and/or transmission of electricity other than Apparatus.
Power	Electrical power or the quantity of electrical energy per unit of time.
Power Balance Statement	Forecast produced by TSOs for each National System of their expected demand and generation over the planning horizon as set out in Chapter 5 (Planning).
Power Island	Has the meaning set out in Chapter 10 (Emergency Operations).
Power System Security	Safe scheduling, operation and control of the power system on a continuous basis.
Power System Stabiliser (PSS)	Equipment controlling the Exciter output via the voltage regulator in such a way that power oscillations of the synchronous machines are dampened. Input variables may be speed, frequency or power (or a combination of these).
Power Transfer	Instantaneous rate at which active energy is transferred between connection points.
Power Transfer Capability	Maximum permitted power transfer through a transmission or Distribution Network or part thereof.
Premises	As defined in the Act.

Word or Phrase	Definition
Primary Response	The immediate automatic proportional increase or decrease of real power output by synchronised Generating Plants and other devices due to a rise or fall in the Kenya National Transmission System frequency requiring changes in the Generating Plants Active Power output to restore the frequency to within operational limits as defined in Chapter 15 (ISBC2 Balancing and Frequency Control).
Prudent Utility Practice	The practices generally accepted and followed by electric utility industry of a Region conforming to the design, construction, operation, maintenance, safety and legal requirements which are attained by exercising that degree of skill, diligence, prudence and foresight which would reasonably and ordinarily be expected from skilled and experienced operatives engaged in the same type of undertaking under the same or similar conditions.
Ramp Rate	Rate of change of electric power output of a Generating Plant.
Reactive Energy	A measure, in varhours (varh) or multiples thereof of the alternating exchange of stored energy in inductors and capacitors, which is the time-integral of the product of voltage and the out of phase component of current flow across a connection point.
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 vars and multiples thereof.
Designated Control Centre (DCC)	A control centre managing the operations of the Users.
Remaining Capacity	The difference between available generating capacity and demand at the reference dates and calculated under normal climatic conditions as stated in Chapter 5 (Planning).
Remedial Action Scheme (RAS)	Also referred to as Special Protection System. RAS means a protection system that automatically initiates one or more control actions following electrical disturbances. Typical examples include tripping Generating Plants or loads and switching of series capacitors, shunt capacitors, or shunt reactors.
Renewable Energy	As defined in the Act.
Variable Renewable Power Plant (VRPP)	For the purposes of the KNTGC, a Generating Plant whose primary energy source is from wind or solar energy and whose generation output is variable in nature.
Reserve	A measure of available capacity over and above the capacity needed to meet normal peak demand levels. In case of a Generating Plant, it is the capacity to generate more or less energy than the system normally

Word or Phrase	Definition
	requires. For a transmission company, it is the capacity to handle additional energy transport if demand levels rise beyond expected peak levels.
Reserve, Regulating	Regulating reserve is reserve that is under central AGC and can respond within ten seconds and be fully active within ten (10) minutes of activation. This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore instantaneous reserve within ten (10) minutes of the disturbance. The provision of Regulating Reserve is a Secondary Response.
Reserve, Spinning	In Kenya, Spinning Reserve is made available as needed to arrest the frequency at acceptable limits following a Contingency, such as a unit trip or a sudden surge in load. The provision of Spinning Reserve is a Primary Response.
Reserve, Tertiary	Refer to Tertiary Reserve.
Response	The provision of a Reserve.
Response, Primary	Refer to Primary Response.
Response, Secondary	Refer to Secondary Response.
Rota Load Disconnection	A planned temporary disconnection of electricity to customers, for a set duration.
RSA ID	RSA ID is a two-factor authentication technology that is used to protect network resources. The two factors typically are: (a) a password or PIN; and (b) an authenticator, could be a hardware token (such as a USB token, smart card or key fob). The software token is the RSA Authentication Manager Software that provides the security engine used to verify authentication requests.
SAIDI (System Average Interruption Duration Index)	SAIDI indicates average minutes of service interruption per customer. It is the sum total of customer minutes interrupted divided by the total number of customers served. SAIDI is considered as one of the best indicators of system stress.
SAIFI (System Average Interruption Frequency Index)	SAIFI is the sum total of number of interruptions divided by the total number of customers
Secondary Response	Secondary Response is the automatic response to a frequency change which is activated within ten seconds and be fully available within ten (10) minutes 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 Generating Plants

Word or Phrase	Definition
	already synchronised to the KNTS and is normally controlled by the SO by AGC.
Significant Incident	An event which has caused or could have caused injury to persons, damage to system equipment or operation of the Kenya National Transmission System outside the operational security standards.
Solar Power Generating Plant	A Generating Plant deriving its source of energy from the sun and for which its generation is variable in nature.
Special Protection System	Refer to Remedial Action Scheme.
Spinning Reserve	See Reserve, Spinning.
Steering Committee	The body established by EAPP in accordance with the Inter-Government Memorandum of Understanding and responsible for the Governance of EAPP.
Sub-committee on Planning	EAPP body under the direction of EAPP Steering Committee responsible for the coordination of Master Plans and development programs of EAPP Member utilities.
Switchyard	Connection point of a Generating Plant into the network, generally involving the ability to connect the Generating Plant to one or more outgoing network circuits.
Synchronisation	The process of connecting a Generating Plant to the power system or two separate AC power sytems.
Synchronous Generator	Alternating current Generating Plants of mostly thermal and hydro (water) driven power turbines which operate at the equivalent speed of frequency of the power system in its satisfactory operating state.
System	As defined in the Act.
System Operation	As defined in the Act.
System Operator	The entity responsible for the overall coordination of the planning and operation of the Kenya National Transmission System, including the scheduling and dispatch of Generating Plants connected to it.
System Tests	Those tests that involve either a simulated or a controlled application of irregular, unusual, or extreme conditions on the Interconnected Transmission System. In addition, they include Commissioning and or acceptance tests on Plant and Apparatus to be carried out by a User that may have a significant impact upon the Kenya National Transmission System and or another National System.
Tariff	As defined in the Act
Tertiary Reserve	Refers to TSO instructed changes in the dispatching and commitment of Generating Plants. Tertiary Reserve is used to restore both Primary

Word or Phrase	Definition
	and Secondary Response, to manage constraints on the KNTS and to bring the frequency to target values when the Secondary Response has been depleted. Where Tertiary Reserve is held on Generating Plants not synchronised to the KNTS, the Generating Plants shall be capable of being synchronised within a specified time generally between fifteen (15) minutes and one (1) hour.
Test Proposal	Outline provided in writing of the actions proposed to be carried out as part of tests involving Plant and Apparatus forming part of the EAPP Interconnected Transmission System.
Test Proposer	The Party proposing System Tests
Total Shutdown	The situation existing when all generation has ceased within the Kenya National Transmission System and there is no supply from External Systems and, therefore, the Kenya National Transmission System has shutdown.
Transmission	As defined in the Act
Transmission Licence	As defined in the Act
Transmission Licensee	A person that is licensed by the Authority to own, operate and maintain transmission assets within the Kenya National Transmission System.
Transmission Metering Administrator	The representative of any of the Users of KNTS in charge of transmission metering.
Transmission Network Service Provider	A person that operates and maintains a transmission network on the KNTS.
Transmission System Capability Statement	Assessment by EAPP Sub-Committee on Planning and TSOs of the capability of the EAPP Interconnected Transmission System to support the required energy flows across both Systems and cross-border connections as set out in Chapter 5 (Planning).
Tribunal	The Energy and Petroleum Tribunal as established under the Act
Transmission System Operator (TSO)	The entity responsible for the overall coordination of the planning and operation of the Transmission System, including the scheduling and dispatch of Generating Plants connected to it.
Unplanned Outage	Any Outage which is not a Planned Outage.
User	Any person or entity connected to or making use of the Kenya National Transmission System as a Generation Licensee, Transmission Licensee, Distribution Licensee or End-user.
User System	The system of a Distribution Licensee, a Transmission Licensee, or a system owned or operated by an End-Use Customer comprising

Word or Phrase	Definition
	Generating Plants Apparatus connecting Generating Plants and/or End-users' equipment to the Kenya National Transmission System.
Vars	Unit of measure of Reactive Power.
Voltage	As defined in the Act
Voltage Dip	A voltage reduction with duration of 10 ms to 1 minute and a voltage drop of more than 10% of the existing value.
Voltage Flicker	The impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time caused by an increase or decrease in voltage.
Voltage Transformer (VT	A transformer for use with meters and/or protection devices in which the voltage across the secondary terminals is, within prescribed error limits, proportional to and in phase with the voltage across the primary terminals
Wind Turbine Generating Plant	A Generating Plant generating electricity from wind, and whose generation is variable in nature

2.3 LIST OF ABBREVIATIONS

The table below provides a summary of the abbreviations used in the *KNTGC.*

Table 2-2: Abbreviations used in the KNTGC

Abbreviation	Meaning
AC	Alternating Current
ACE	Area Control Error
AfDB	African Development Bank
AGC	Automatic Generation Control
AMP	Actual Metering Point
AS	Ancillary Services
AVR	Automatic Voltage Regulator
CAIDI	Customer Average Interruption Duration Index
CC	Connections Chapter
CDs	Compact Disks
CEO	Chief Executive Officer
COMESA	Common Market for Eastern and Southern Africa
COUE	Cost of Unserved Energy
CT	Current Transformer

Abbreviation	Meaning
DC	Direct Current
DCF	Discounted Cash Flow
DCS	Data Collection System
DEC	Data Exchange Chapter
DER	Distributed Energy Resources
DMP	Defined Metering Point
DR	Demand Response
DTE	Data Terminal Equipment
DVDs	Digital Video Disks
EAC	East African Community
EAPP	Eastern Africa Power Pool
EAPP CC	Eastern Africa Power Pool Communications Centre
EAPP DCS	EAPP Data Collection System
EAPP IC	Eastern Africa Power Pool and East African Community Interconnection Code
EHV	Extra High Voltage
EMS	Energy Management System
EUE	Expected Unserved Energy
FACTS	Flexible Alternating Current Transmission System
FTP	File Transfer Protocol
GC	General Conditions
GCR	Generation Plant Connection Requirements, as defined in Section 6.2 of the KNTGC
GD	Glossary and Definitions
GoK	Government of Kenya
GPS	Global Position System
HV	High Voltage
HVDC	High Voltage Direct Current
IC	Interconnected System
ICCP	Inter-Control Centre CommunicationsProtocol
IEC	International Electrotechnical Commission
IG-MoU	Inter-Governmental Memorandum of Understanding
IMC	Interchange Metering Chapter

Abbreviation	Meaning
INEP	Integrated National Energy Plan
IP	Interchange Point
ISBC 1, ISBC 2, ISBC 3	Interchange Scheduling and Balancing Chapters14 ,15 and 16 of the KNTGC
ISO	International Standard Organisation
IU-MoU	Inter-Utility Memorandum of Understanding
KNDS	Kenya National Distribution System
KNTS	Kenya National Transmission System
KMC	Kenya Metering Code
KNTGC	Kenya National Transmission Grid Code
KS IEC	Kenya Standard IEC
LIWL	Lightning Impulse Withstand Level
MCR	Maximum Continuous Rating
MIR	Meter Information Register
MTBF	Meantime Between Failure
MTTR	Meantime To Repair
NPV	Net Present Value
NTC	Net Transmission Capability
OC 1, OC2, OC3, OC 4, OC 5, OC 6	Operations Chapters 8, 9, 10, 11, 12 and 13 of the KNTGC
PC	Planning Chapter
PCC	Point of Common Coupling
PSS	Power System Stabiliser
PV	Photovoltaic
QoS	Quality of Service
RAS	Remedial Action Scheme
RCC	Regional Control Centre
VRPP	Variable Renewable Power Plant
RTU	Remote Terminal Unit
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SIWL	Switching Impulse Withstand Level

Abbreviation	Meaning
SMTP	Simple Mail Transfer Protocol
SO	System Operator, in Kenya
SOTC	System Operator Training Chapter
SPS	Special Protection Scheme
TCP/IP	Transmission Control Protocol/Internet Protocol
TMA	Transmission Metering Administrator
TNSP	Transmission Network Service Provider
TSO	Transmission System Operator
U_m	Voltage Maximum
U_n	Voltage Nominal
VT	Voltage Transformer
WAN	Wide Area Network (computer networkdesigned to cover a wide geographic region,usually over telephone lines)

2.4 LIST OF UNITS

The table below provides a summary of the units used in the *KNTGC*.

Table 2-3: List of Units

Symbol	Unit
Amp	Ampere
GW	Gigawatt (1,000,000,000 W)
GWh	Gigawatt-hour
h, Hr, hrs	Hour
Hz	Hertz
Kbps	Kilobits per second
kV	Kilovolt
kVA	Kilovolt-ampere
kvar	Kilovars
kW	Kilowatt
kWh	Kilowatt-hour

Symbol	Unit
Mbps	Megabits per second
mHz	Milli hertz (1/1000 Hz)
Min	Minute
ms	Milli second (1/1000 s)
MVA	Megavolt-ampere
Mvar	Megavars
Mvarh	Megavar-hour
MW	Megawatt
MWh	Megawatt-hour
s, sec	Second
TW	Terawatt (1,000,000,000,000 W)
V	Volt
W	Watt

3 GENERAL CONDITIONS

3.1 INTRODUCTION

The General Conditions (GC) set out the over-riding principles to be used in the operation of the *Kenya National Transmission System* (*KNTS*) and form the basis for the decisions of a reasonable and prudent operator should specific events not be covered by the relevant code. The GC describes the provisions necessary for the overall administration and review of the various aspects of the *KNTGC*. The GC also deal with those aspects of the *KNTGC* not covered in other chapters, including the resolution of disputes, bilateral agreements, confidentiality, non-compliance and the revision of the *KNTGC* through recommendations of the *Kenya National Transmission Grid Code Review Committee*.

3.2 SCOPE

These General Conditions apply to the *Authority*, the *SO*, and *Users* of the *Kenya National Transmission System*.

3.3 OBJECTIVE

The General Conditions contains provisions, which are of a general nature and apply to all chapters of the KNTGC. The objectives of the GC are to ensure, to the extent possible, that the various chapters of the *KNTGC* work together and work in practice for the benefit of the *SO and Users*.

3.4 IMPLEMENTATION AND ENFORCEMENT

The *Authority* is responsible for the implementation and enforcement of the *KNTGC*.

The Authority may, in certain cases, need access to services and facilities of *Users*, or to issue instructions to Users to implement and enforce the *KNTGC*. Accordingly, all *Users are* required not only to abide by the letter and spirit of the *KNTGC*, but also to provide the *Authority with* such rights of access, services and facilities and to comply with any instructions of the *Authority*.

Each *Party* shall, at all times, in its dealings with other *Parties* to the *KNTGC* act in good faith and in accordance with *Prudent Utility Practice*.

3.5 SAFETY AND ENVIRONMENT

Nothing in or pursuant to this *KNTGC* shall be taken to require a *Party* to do anything which could or would be unsafe or contrary to the Party*'s Environmental, Health and Safety Obligations as prescribed by all other applicable laws and regulations.*

3.6 UNFORESEEN CIRCUMSTANCES

If circumstances arise which are not contemplated by the provisions of the *KNTGC*, the *Authority shall*, to the extent reasonably practicable in the circumstances, consult promptly with all affected *Users* in an effort to reach agreement as to what should be done. If agreement between the *Authority* and such *Users* cannot be reached in a reasonable time, the *Authority* shall determine the best course of action in accordance with *Prudent Utility Practice*.

Each *User* shall comply with all instructions given to it by the *Authority following* such a determination provided the instructions are consistent with the then current technical parameters of the *KNTS*. The

Authority shall, as soon as reasonably practicable following the unforeseen circumstances, notify all relevant details to the *Kenya National Transmission Grid Code Review Committee* for consideration and recommendations in accordance with Chapter 4 (Governance).

3.7 FORCE MAJEURE

In situations of *Force Majeure,* the provisions of the *KNTGC* may be suspended in whole, or in part, pursuant to any directions given by the *Authority being* the custodian of the *KNTGC*.

Neither *Party* shall be held to have defaulted in respect of any obligation under the *KNTGC* if prevented or delayed from performing that obligation, in whole or inpart, because of a *Force Majeure* event. If a *Force Majeure* event prevents or delays a *Party* from performing any of its obligations under the *KNTGC*, that *Party* shall:

(a) Promptly notify any other *Party* involved and the *Authority* of the *Force Majeure* event and its assessment in good faith of the nature and the effect that the event will have on its ability to perform any of its obligations and the measures that the *Party* proposes to take to alleviate the impact of the *Force Majeure* event. If the immediate notice is not in writing, it shall be confirmed in writing as soon as reasonably practicable. The notice shall be posted on the *Authority* website.

(b) Not be entitled to suspend performance of any of its obligations under the KNTGC to any greater extent or for any longer time than the *Force Majeure* event requires it to do;

(c) Use its best efforts to mitigate the effects of the *Force Majeure* event, remedy its inability to perform, and resume full performance of its obligations;

(d) Keep the other *Party* and the *Authority* continually informed of its efforts, and

(e) Provide written notice to the other *Party* and the *Authority* when it resumes performance of any obligations affected by the *Force Majeure* event. The notice shall be published on the *Authority* website.

3.8 COMPLIANCE

(a) All parties shall comply with the *KNTGC*.

(b) *Users* shall inform the *Authority* of any non-compliance report without delay, but no later than thirty (30) days after becoming aware of the item unless there is significant risk to the *Kenya National Transmission System*, which then must be reported immediately.

(c) The *Authority* may require a participant to provide the *Authority* with information that it deems necessary for the proper administration of the *KNTGC*. This information shall be treated as confidential.

(d) Upon a report or suspicion of non-compliance the *Authority* may seek to:

  (i) Resolve the issue through negotiation

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

  (iii) Consider an application for amendment

  (iv) Consider an application for exemption.

(e) Application for exemption or suspension of obligations under the *KNTGC* is treated under Section 3.9 Non-Compliance.

3.9 NON-COMPLIANCE

If a *User* finds that it is, or will be unable to comply with any provision of this *KNTGC*, then that *Party* shall without delay, but not later than thirty (30) days after discovery, report such non-compliance to the *Authority*. After which the provisions of 3.10 shall apply.

3.9.1 Non-Compliance Situations

If the *User* fails to fulfil all the provisions established in the *KNTGC*, it shall be considered a Non-Compliance situation.

A Non-Compliance situation will include, but is not limited to:

(a) Failure to provide the *Authority*, on time, all required information in the KNTGC

(b) Providing the *Authority* incomplete or inaccurate data or reports, in particular inaccuracies or other problems verified by the audits of the *Authority*

(c) Failure to implement in time the procedures and information systems required in the *KNTGC*

(d) Failure or unsuitable delays in the execution of the approved remedial actions and plans to comply with *KNTGC* provisions following the approval of a *Derogation* and mitigation plan.

3.9.2 Penalties

If the *Authority* determines that the *User* is in a non-compliance situation for which *a Derogation* has not been filed or is in the process of being filed, or for which a *Derogation* has not been approved by the *Authority*, or is in violation of the terms of an approved *Derogation*, the *Authority* will determine and apply applicable penalty for the non-compliance situation. The amount of the penalty will be determined by the *Authority* depending on the type and the level of non-compliance, taking into consideration the following factors:

(a) Severity of the non-compliance and any environmental, health, and safety impacts

(b) Instances of repeated and deliberate non-compliance

(c) Penalties shall be comparable to those specified in other laws, regulations, and applicable contracts

(d) Penalties shall be set at a level such that non-compliance will not be economically preferable to compliance

The *Authority* shall also consider that the *User* may be in non-compliance with its licence conditions, and may suspend or revoke the licence.

3.10 DEROGATION

The *Authority* may issue *Derogations* suspending a *User*'s obligations to implement or comply with the *KNTGC* to such an extent as may be specified in the *Derogations.*

If a *User* finds that it is, or will be, unable to comply with any provision of the *KNTGC*, then they shall, without delay, report such non-compliance to the *Authority*. The applicant may request an exemption from the *KNTGC* requirement, or request additional time to correct the non-compliance item.

3.10.1 Request for Derogation

A *Party* seeking derogation from any provision in the *KNTGC* shall make a written request to the *Authority* containing the following information. Refer also to the sample Request for *Derogation* form in Appendix A.

(a) Name of *Party* applying for *Derogation*;

(b) Contact information, name and signature of CEO or other corporate officer delegated by the CEO;

(c) Whether the *Derogation* sought is permanent exemption or for a delay in achieving compliance, and if a delay in achieving compliance is being sought, the date by which the mitigation plan will be filed and the non-compliance will be remedied;

(d) The specific provision of the *KNTGC* (section title and number) against which the present or predicted non-compliance is identified;

(e) The date of non-compliance discovery and reporting of the non-compliance;

(f) The nature and extent of the non-compliance;

(g) The cause for non-compliance;

(h) Identification and description of the system, facility, equipment, process, procedure or specific connection point in respect of which *Derogation* is sought;

(i) A description of any health and safety implications and the associated risk management measures;

(j) A description of the proposal for restoring compliance (where applicable) including details of actions to:

    (i) Mitigate risks to *Customers*or other *Users*

    (ii) Restore compliance (including timetable of works)

(k) A description of the reasonable alternative actions that have been considered;

(l) A statement of the expected duration of the non-compliance.

The *User* is required to justify the derogation request in terms of both the specific circumstances and the expected duration. *Users* are advised to give as much notice as possible when making *Derogation* requests since *Derogations* will not be granted unless the *Authority* is satisfied that the request is justified.

3.10.2 Derogation Review

Upon receipt of any request for *Derogation*, the *Authority* shall promptly consider such a request provided that the *Authority* considers that the grounds for the *Derogation* are reasonable. In its consideration of a *Derogation* request, the *Authority may* contact the relevant *User* to obtain clarifications, request additional information or to discuss changes to the request, and review possible remedial actions to achieve compliance.

The *Authority* may initiate at its own initiative a review of any existing *Derogations*, and any *Derogations* under consideration where a relevant and material change in circumstance has occurred.

The *Authority may* also seek the views and advice of an *Independent Expert* on the proposed *Derogation*, as set out in Section 3.12 of this chapter.

It may be the case that not all *Plant* and *Apparatus* in use as at the date of adoption of this *KNTGC* will be able to meet the requirements of the *KNTGC*. In some cases, it may not be economically or technically possible to upgrade such existing *Plant* and *Apparatus* to the required standards. Where this is the case the *Authority* will give consideration to a time bound *Derogation* for all or part of the *KNTGC.*

In the event that *Derogation* is granted, the *User* shall take all necessary action to ensure full compliance with the *Derogation.*

Where a material change in circumstances has occurred, a review of any existing *Derogation* and any *Derogation* under consideration may be initiated by the *Authority*.

3.10.3 Derogation Register

The *Authority* shall keep a register of all *Derogations* which have been granted, identifying the name of the *User* and *Plant* and *Apparatus* in respect of which the *Derogation* has been granted, the relevant provision of the KNTGC, the period of *Derogation* and the extent of compliance with the provisions. The register of *Derogations* shall be published on the *SO Website*.

Upon request from any *User*, the *Authority* shall provide a copy of such register of *Derogations* to such *User.*

3.10.4 Transitional Provisions

Transitional Provisions are intended to facilitate compliance and reduce the need for *Derogation* requests to suspend obligations under *KNTGC* provisions.

Transitional Provisions are provisions of the *KNTGC* approved by the *Authority* that shall not apply either in whole or in part to some or all *Users*. They differ from a *Derogation*in that:

(a) They cover potentially many *Users*

(b) They can be sought by a group of *Users* with similar needs to suspend obligations

(c) In appropriate circumstances, the *Authority* can initiate a Transitional Provision

(d) Situations which might require the use of Transitional Provisions include (but are not limited to):

  (i) The effective date of the *KNTGC* and its impact on requirements, such as multiple old *Generating Plants* that need equipment upgrade in order to reach compliance

  (ii) Discovery of a common-mode problem with equipment

Transitional Provisions may require a plan of how the affected *Users are* going to reach compliance, or reasons why they should be permanently exempt.

3.11 DISPUTE RESOLUTION

3.11.1 Mutual Discussion

If a *Dispute* between *the Authority* and any *User* or between *Users* in connection with, or arising out of, the interpretation, implementation or breach of any provision in this *KNTGC*, any *Party* may issue to the other *Party* a written notice (the "*Dispute Notice*") outlining the matter in *Dispute*. Following issue of a *Dispute Notice* both *Parties* shall discuss in good faith and attempt to settle the *Dispute* between them.

Dispute resolution may include a request to the *Authority* to refer the matter to the *Kenya National Transmission Grid Code Review Committee* to consider the disputed *KNTGC* provisions and offer recommendations on resolution of the *Dispute*.

3.11.2 Determination by the Authority

If the *Dispute* cannot be settled within thirty (30) business days after issue of the *Dispute Notice*, either *Party* shall have the right to refer the *Dispute* to the *Authority* for resolution. In this case, the procedure will be as follows:

(a) The request for referral shall be made in writing to the *Authority* and a dated copy of the original *Dispute Notice* between the *Parties* shall be attached;

(b) Upon receipt of a request for referral, the *Authority* shall write to the Parties acknowledging that the *Dispute* has been referred to the *Authority* for determination;

(c) Following receipt of *Authority* acknowledgment, each Party shall have five (5) business days to submit their reason(s) as to the cause of the *Dispute* in writing to the *Authority*, and

(d) No later than ten (10) business days after the *Authority* has received each *Party*'s reason(s) as to the causes of the *Dispute* in writing, the *Authority* shall write to each *Party* setting out the manner in which it intends to resolve the *Dispute* and indicate a date by which a determination may be expected which in any case shall not exceed sixty (60) days. The *Authority* may also seek the views and advice of an *Independent Expert* on settlement of the *Dispute* as set out in Section 3.12 of this chapter.

The determination by the *Authority*shall be legally binding on all *Parties*.

Determinations by the *Authority* are subject to appeal before the *Tribunal* as provided under the *Energy Act.*

3.12 INDEPENDENT EXPERT OPINION

If any matter is referred to an *Independent Expert*, he shall be appointed by the *Authority* as appropriate. Such person shall be an expert with specialised skills in the matter under consideration and must not have any material relationship with any of the *Parties* to the matter. When referring a matter to an *Independent Expert* a written brief shall be prepared containing:

(a) A description of the *Derogation* requested or the matter on which the *Independent Expert* is required to express an opinion or give advice;

(b) All the relevant documentation;

(c) All the relevant correspondence between Parties, and

(d) A request that the *Independent Expert* drafts an opinion setting out a possible solution to the issue.

The *Independent Expert* shall determine the procedure to be followed for the purpose of preparing an opinion. The venue for the *Independent Expert's* inquiries will be agreed between the *Parties* to the matter under consideration. Modern technologies such as video conferencing may be used to ensure that the process is as cost efficient and equitable as possible.

The *Independent Expert* must within fifteen (15) business days of his appointment accept submissions from the *Parties* in dispute and must state his determination of those matters within sixty (60) business days of his appointment.

Responsibility for the entire cost of the *Independent Expert* shall be:

(a) In the case of referral pursuant to Section 3.9 in this chapter, *Party* or *Parties* seeking revision of the *KNTGC* shall equally divide the entire cost;

(b) In the case of referral pursuant to Section 3.10 in this chapter, the *Party* or *Parties* seeking *Derogation* pursuant to Section 3.10 in this chapter shall equally divide the entire cost;

(c) In the case of referral pursuant to Section 3.11 in this chapter, the disputing Parties shall equally divide the entire cost.

3.13 KNTGC INTERPRETATION

In the event that any *User* requires additional interpretation of the wording or application of any provision of the *KNTGC*, they may make a request to the *Authority* for such interpretation. Provided that the request is reasonable, the *Authority* shall provide the *User* with an interpretation of the relevant provision. In the event that a *User*, acting reasonably, deems that an interpretation provided by the *Authority* is unreasonable or inappropriate, the matter shall be resolved as provided in Section 3.11 Dispute Resolution of the *KNTGC*.

3.14 HIERARCHY

In the event of any conflict between the provisions of the *KNTGC* and any contract, bilateral agreement or arrangement between a *Transmission Licensee, Distribution Licensee,* or other *Users*, the provisions of the KNTGC shall prevail unless the KNTGC expressly provides otherwise.

3.15 CONFIDENTIALITY

All data relating to and exchanged among Parties concerning the KNTS shall be considered to be *Confidential Information*. The *Authority* shall consult with the *SO and Users* in regard to the publication of any of the data exchanged. Aggregate data may be made available by the *SO* when requested by a *User*. These data shall be used only for the purpose specified in the request and shall be treated by the *User* as confidential. All such disclosure of *Confidential Information* shall be subject to a written Confidentiality Agreement duly signed by the *SO* and *Users*. Such *Confidential Information* shall not be disclosed to other parties without the express written consent of the parties to the Confidentiality Agreement.

3.15.1 Confidential Information

Each *Party* shall use all reasonable endeavours to keep confidential any *Confidential Information* which comes into the possession or control of that *Party* or of which the *Party* becomes aware. The information owner may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, is provided.

A *Party*:

(a) Shall not disclose confidential information to any person except as permitted by the *KNTGC*.

(b) Shall only use or reproduce confidential information for the purpose for which it was disclosed or another purpose contemplated by the *KNTGC and consistent with the provisions of section 211 of the Act*;

(c) Shall not permit unauthorised persons to have access to *Confidential Information.*

Each *Party* shall use all reasonable endeavours:

(a) To prevent unauthorised access to *Confidential Information* which is in the possession or control of that *Party*; and

(b) To ensure that any person to whom he discloses *Confidential Information* observes the provisions of this Section 3.15.1 in relation to that information.

(c) To control unauthorised access to confidential information and to ensure secure information exchange. *Parties* 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).

3.15.2 Exceptions

This section does not prevent:

(a) The disclosure, use or reproduction of information if the relevant information is at the time generally and publicly available other than as a result of breach of confidence by the *Party* who wishes to disclose, use or reproduce the information or any person to whom the *Party* has disclosed the information;

(b) The disclosure, use or reproduction of information to the extent required by law or by a lawful requirement of any government or governmental body, authority or agency having jurisdiction over a *Party* or his related bodies corporate; or

(c) The disclosure, use, or reproduction of information if required in connection with legal proceedings.

3.15.3 Application of Confidentiality to the Authority

For the purpose of Section 3.15, other than Section 3.15.4, *Party* includes the *Authority* and any council, committee or other body established by the *Authority* under the *KNTGC*.

3.15.4 Indemnity to the Authority

Each *Party* indemnifies the *Authority* against any claim, action, damage, loss, liability, or expense which the *Authority* pays, suffers, incurs, or is liable for in respect of any breach by that *Party* or any officer, *Agent* or employee of that *Party* of this Section 3.15.4 of the *KNTGC*.

3.15.5 Party Information

Each *Party* shall develop and, to the extent practicable, implement a policy to protect information that is acquired pursuant to the various functions from use or access which is contrary to the provisions of the *KNTGC*.

3.15.6 Information on Kenya National Transmission Grid Code Bodies

The *Authority* shall develop and implement policies concerning:

(a) The protection of information which *KNTGC* bodies acquire pursuant to their various functions from use or access by *Parties* or *KNTGC* bodies which is contrary to the provisions of the *KNTGC*; and

(b) The dissemination of such information where appropriate to *Parties* and other interested parties.

4 GOVERNANCE

4.1 INTRODUCTION

The objective of this Governance Chapter is to describe the provisions necessary for the overall administration and review of the various aspects of the *KNTGC*. This chapter also summarises the main documents and organisations that provide the authority governing the planning, construction, and operation of the *Kenya National Transmission System.*

This *KNTGC* shall be read in conjunction with the relevant legislation including the *Energy Act of 2019, Energy (Electricity Supply) Regulations, 2021* and any applicable amendments related to the administrative authority for the *KNTGC*. The KNTGC requirements shall also be applied in conjunction with the licences issued to *Generation Licensees*, Transmission companies and *Transmission Network Service Provider*s and regulations that relate to the Electricity Supply Industry adopted by the *Authority* and the *Ministry of Energy.* All *Transmission Licences* and agreements concluded after implementation of the KNTGC shall include the obligation of parties to comply with *KNTGC* requirements.

This chapter also describes the methodology that will be used to:

(a) Ensure that *User*s are represented in reviewing and making recommendations to the development and revision of the *KNTGC* requirements;

(b) Facilitate the monitoring and auditing of compliance with the *KTNGC*;

(c) Specify the processes used for the settlement of disputes.

4.2 GOVERNANCE DOCUMENTS

The primary laws defining governance are the Kenya's *Energy Act No. 1 of 2019* and the *Energy (Electricity Supply) Regulations, 2021*. The Energy Act established the Authority, the Rural Electrification and Renewable Energy Corporation (REREC), the Nuclear Power and Energy Agency (NuPEA) and the Tribunal. The organisations with governance functions include the Authority, the Tribunal, and the Ministry of Energy.

4.3 THE KENYA NATIONAL GRID CODE REVIEW COMMITTEE

The Authority shall constitute and maintain the Kenya National Grid Code Review Committee in accordance with the relevant provisions of the Energy (Electricity Supply) Regulations of 2021.

The role of the *Kenya National Grid Code Review Committee* shall be as stipulated in the *Energy (Electricity Supply) Regulations of 2021.*

4.4 REVISIONS TO THE KENYA NATIONAL TRANSMISSION GRID CODE

The Authority is responsible for the review of the operations and revision of the KNTGC and will be informed by the recommendations of the *Kenya National Grid Code Review Committee.*

Any Distribution Network User, Kenya National Grid Code Review Committee member, DNSP, Transmission Licensee, the System Operator, the Ministry of Energy or the Authority may propose revisions to the KNTGC.

Before approving any proposed revisions to the KNTGC, the Authority will be guided by the Grid Code Review Committee recommendations on the matter and any representations made by Parties. In considering the proposed revisions, the Authority may also seek the opinion of an Independent Expert

The Authority shall, as required, prepare and issue amended versions of the *KNTGC* containing such revisions as have been approved by the *Authority*. All revisions to the *KNTGC* shall be recorded in the *Kenya National Distribution Code Revision Register*, which shall indicate the date, chapter amended and the reason for the change. An up to date *KNTGC* including all approved revisions shall be published on the *Authority* website along with the *Kenya National Distribution Code Revision Register*. The revised version of the *KNTGC* shall take effect from the date on which it is published on the *Authority* website, or such other later date as specified by the *Authority*

4.5 KENYA NATIONAL TRANSMISSION GRID CODE AUDITS

4.5.1 Customer Request

A *User* may request from the *Transmission Network Service Provider*, or a *TNSP* may request from a *User*, any material in the possession or control of that participant relating to compliance with a section of the *KNTGC*. The requesting participant may not request such information in relation to a particular section of the *KNTGC* within six (6) months of a previous request made under this section in relation to the relevant section.

4.5.2 Information Requirements

A request under this section 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

4.5.3 Withholding of Information

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.

4.6 CONTRACTING

The *KNTGC* shall be one of the standard documents that form part of the contract between *TNSPs* and each of their *Customer*s. *TNSPs* shall contract with *Customer*s for any services specified in the *KNTGC*.

4.7 REGISTRATION OF LICENSEES

4.7.1 Users

Transmission Network Service Providers shall ensure that transmission agreements between *TNSPs* and *Users* after the implementation of the *KNTGC* shall include an obligation on *Users* to comply with *KNTGC* requirements.

4.7.2 Licensed Entities

The *Authority* shall ensure that all *Licensees* comply with *KNTGC* requirements.

4.7.3 Registration of Kenya National Transmission Grid Code Licensees

No entity shall have access to the *Kenya National Transmission System* before obtaining a licence from the *Authority*. The *Authority* shall be responsible for creating and maintaining a register of *Licensees*. Transmission Network Service-providers shall ensure that *Users, excluding consumers* are registered as *Licensees* before entering into a contract for services with such *Users*.

A *User* who no longer holds a licence from the *Authority* shall be removed from the register of *Licensees*.

4.8 NOTICES

4.8.1 Service of Notices under the Kenya National Transmission Grid Code

A notice is properly given under the *KNTGC* to a person if:

(a) It is personally served; or

(b) A letter containing the notice is prepaid and posted to the person at an address (if any) supplied by the person to the sender for service of notices or, where the person is a *User*, an address shown for that person in the register of *Users* to whom licences have been issued under the *Act* and maintained by the *Authority* or, where the addressee is the *Authority*, the registered office of the *Authority*; or

(c) It is sent to the person by electronic format to a number or reference which corresponds with the address referred to in Section 4.8.1(b) or which is supplied by the person to the *Authority* for service of notices; or

(d) It is published in a newspaper with wide circulation in the area where the person is resident or in a daily newspaper circulated generally;

(e) It is communicated verbally to the person and that communication is recorded or thereafter confirmed in writing; or

(f) The person receives the notice.

4.8.2 Time of Service

A notice is treated as being given to a person by the sender:

(a) Where sent by post in accordance with Section 4.8.1(b):

  (i) to an address in the central business district of Nairobi, on the second business day after the day on which it is posted;

  (ii) to any other address, on the third business day after the day on which it is posted;

(b) Where sent in electronic format in accordance with Section 4.8.1(c):

(i) Where the notice is of a type in relation to which the addressee is obliged under the *KNTGC* to monitor receipt by electronic mail outside of, as well as during, business hours, on the day when the notice is recorded as having been first received at the electronic mail destination; and

(ii) In all other cases, on the day when the notice is recorded as having been first received at the electronic mail destination, if a business day or if that time is after 1600 Hr (addressee's time), or the day is not a business day, at 0900 Hr on the following business day; or

(c) Where published in a newspaper in accordance with Section 4.8.1(d), on the next day after the date of publication of the notice;

(d) In any other case, when the person actually receives the notice.

4.8.3 Counting of Days

Where a specified period (including, without limitation, a particular number of days) shall elapse or expire from or after the giving of a notice before an action may be taken neither the day on which the notice is given nor the day on which the action is to be taken may be counted in reckoning the period.

4.8.4 Reference to Addressee

In this section, a reference to an addressee includes a reference to an addressee's officers, *Agents*, or employees or any person reasonably believed by the sender to be an officer, *Agent* or employee of the addressee.

4.9 ENFORCEMENT

4.9.1 Investigations

(a) A *User* shall, if requested by the *Authority*, supply it with information relating to any matter concerning the *KNTGC* in such form, covering such matters and within such reasonable time as the *Authority* may request.

(b) If a User fails to comply with a request by the *Authority* for information as described in Section 4.9.1(a), the *Authority* may appoint a person to investigate the matter and to prepare a report or such other documentation as the *Authority* may require. A *User* shall assist the person to undertake the investigation and to prepare the report or other documentation. In addition, a *User* shall, at the request of the person appointed, direct third-parties to make available such information as the person may reasonably require.

(c) The cost of the investigation and of preparing the report or other documentation prepared by the person appointed shall be met by the *User* directed to supply the information under Section 4.9.1(a) unless the *Authority* otherwise determines.

(d) Any report or other documentation referred to in this Section 4.9.1 may be used in any proceeding involving the *Authority* under the *Act* or for the purpose of commencing any such proceeding.

(e) The *Authority* shall develop and implement guidelines in accordance with the *KNTGC* consultation procedures governing the exercise of the powers conferred on it by this Section 4.9.1.

(f) The guidelines referred to in Section 4.9.1(e) shall set out the circumstances that a *User* will be required to bear the cost of providing the information sought by the *Authority* under this Section 4.9.1, including where no breach of the *KNTGC* by the relevant *User* has occurred.

4.9.2 Entry and Inspection

The *Authority* and its authorised officers and representatives shall have such rights of entry to premises and installations as may be granted under the *Act*.

4.9.3 Functions of the Authority

The functions of the *Authority* are set out in the *Energy Act.*

4.9.4 Alleged Breaches of the Kenya National Transmission Grid Code

(a) If a *User* considers that another *User* may have breached or may be breaching this *KNTGC or* any provision in their *Connection Agreement,* the aggrieved *User* may, in accordance with this *KNTGC or* the terms of their *Connection Agreement*:

   (i) Give notice to the person in breach to immediately take steps to remedy and/or stop the breach, as the case may be;

   (ii) Subject to Section 4.14.4, impose any sanctions on the person in breach as provided in this *KNTGC or* their *Connection Agreement* and

   (iii) Without limitation to his powers, use reasonable endeavours to give effect to any sanctions so imposed.

(b) If the Authority considers that:

   (i) A *User* may have breached or may be breaching the *KNTGC*; and

   (ii) Given the circumstances of the breach it would be appropriate that a sanction or sanctions be imposed on that *User*, the *Authority* shall notify the *User* of the alleged breach and details of the sanctions which may be imposed if the breach is established.

(c) If the Authority receives written information from a *User* or any other person which alleges a breach of the *KNTGC* by a *User*, the *Authority* shall within five (5) business days of receipt of the information determine whether, based on that information, there would appear prima facie to be a breach of the *KNTGC*.

(d) If the *Authority* considers that a *User* may be the subject of a *disconnection* order it shall:

   (i) Promptly notify the *Users* which the *Authority* considers may be affected; and

   (ii) Without limitation to its powers, use reasonable endeavours to give effect to any arrangements notified to the *Authority* by the *Users* for ensuring the continuation of *supply* to the relevant purchasers of electricity.

4.9.5 Sanctions

The nature of sanctions that may be imposed under the *KNTGC* and the circumstances in which a *User* or the *Authority* may implement any sanction that has been imposed, shall be set out in regulations.

4.9.6 Action of the Authority

(a) The *Authority* may direct a *User* or any person to do or refrain from doing anything that the *Authority* thinks necessary or desirable to give effect or assist in giving effect to any of its orders.

(b) Without limiting the generality of Section 4.9.6(a), the *Authority* may direct a *Transmission Network Service Provider* to *disconnect* a *User* from any *transmission system* in order to assist in giving effect to any of its orders.

(c) A User or any person shall comply with a direction given under Section 4.9.6(a).

4.9.7 User Actions

If any partner, *Agent*, officer, or employee of a *User* does any act or refrains from doing any act which if done or not done (as the case may be) by a *User* would constitute a breach of the *KNTGC*, such act or omission shall be deemed for the purposes of this Section 4.14.7 to be the act or omission of the *User* concerned.

4.9.8 Publications

(a) The *Authority* shall publish a report at least once every six (6) months setting out a summary for the period covered by the report of:

(i) Matters which have been referred to it;

(ii) All its findings during that period; and

(iii) Any sanctions it applied under the *Act*.

(b) In considering the circulation of a report under Section 4.14.8(a), the *Authority* shall have regard to *KNTGC* objectives.

(c) In addition to the regular publication described in Section 4.14.8(a), the *Authority* may publish a report on any one or more matters that have been referred to it, its findings in relation to those matters and any sanctions imposed in relation to those matters. A decision by the *Authority* to publish a report under this Section 4.14.8(c) is a reviewable decision.

(d) No *User*, or former *User* is entitled to make any claim against the *Authority* for any loss or damage incurred by the *User* or former *User* from the publication of any information pursuant to Section 4.14.8(a) or(c) if the publication was done in good faith. No action or other proceeding will be maintainable by the person or *User* referred to in the publication against the *Authority* or any person publishing or circulating the publication on behalf of the *Authority* and this section operates as leave for any such publication except where the publication was not done in good faith.

4.9.9 System Security Directions

(a) Notwithstanding any other provisions of the *KNTGC,* a *User* shall follow any direction issued by or on behalf of the *SO*, which the *SO* is entitled to issue in exercising its powers under the Operations Chapters of the *KNTGC* relevant to maintaining or restoring *Power System Security*.

(b) Any event or action required to be performed pursuant to a direction issued under the Operations Chapters of the *KNTGC* on or by a stipulated day is required by the *KNTGC* to occur on or by that day, whether or not a business day.

(c) Any failure to observe such a direction will be deemed to be a breach of the *KNTGC.*

(d) Any *User* who is aware of any such failure or who believes any such failure has taken place shall refer the allegation to the *Authority* in accordance with the procedures contained in Section 4.14.4.

4.10 MONITORING AND REPORTING

4.10.1 Monitoring Objectives

(a) The *Authority* is responsible for monitoring compliance with and shall use its reasonable endeavours to ensure the effectiveness of the *KNTGC* in accordance with its objectives.

(b) The Authority shall undertake such monitoring as it considers necessary:

(i) To determine whether *Users* are complying with the *KNTGC;*

(ii) To assess whether the dispute resolution, *KNTGC* enforcement, *KNTGC* change and other mechanisms are working effectively in the manner intended;

(iii) To determine whether in its operation, the *KNTGC is* adequately giving effect to objectives specified in the *KNTGC;* and

(iv) To collect, analyse, and disseminate information relevant and sufficient to enable the *Authority* to comply with its reporting and other obligations and powers under the *KNTGC.*

(c) The Authority shall ensure that, to the extent practicable in light of the objectives set out in Section 4.15.1(b), the monitoring processes which it implements under this Section 4.15:

(i) Are consistent over time;

(ii) Do not discriminate unnecessarily between *User*s;

(iii) Are cost effective to both the *Authority* and all *User*s; and

(iv) Are publicised or information relating thereto is available to any person, subject to any requirements as a result of the confidentiality obligations.

4.10.2 Reporting Requirements and Monitoring Standards

(a) The *Authority* shall establish:

(i) Reporting requirements for *Users* in relation to matters relevant to the *KNTGC;* and

(ii) Procedures and standards applicable to the *Authority* and *Users* relating to information and data received by or from *Users* in relation to matters relevant to the *KNTGC.*

(b) Prior to establishing requirements or standards and procedures referred to in Section 4.15.2(a), the *Authority* shall consult with such *Users* as the *Authority* considers appropriate. In formulating requirements or procedures and standards, the *Authority* shall take into consideration the monitoring objectives set out in Section 4.15. The reporting requirements and standards and procedures established by the *Authority* are reviewable decisions.

(c) Subject to Section 4.15.2(d), the *Authority* shall notify to all *Users* particulars of the requirements, procedures, and standards that it establishes under this Section 4.15.2.

(d) If the *Authority* establishes additional or more onerous requirements or procedures and standards which do not apply to all *Users* and the *Authority* considers that notification of those matters to all *Users* would contravene the confidentiality provisions in Section 3.15, the *Authority* shall notify only those *Users* to whom the requirements or procedures and standards apply.

(e) Each *User* shall comply with all requirements, procedures and standards established by the *Authority* under this Section 4.15.2 to the extent that they are applicable to him within the time period specified for the requirement, procedure or standard or, if no such time period is specified, within a reasonable time. Each *User* shall bear his own costs associated with complying with these requirements, procedures, and standards.

(f) In complying with his obligations or pursuing his rights under the *KNTGC,* a *User* shall not recklessly or knowingly provide, or permit any other person to provide on behalf of that *User*, misleading or deceptive data, or information to any other *User* or to the *Authority*.

(g) Any *User* may ask the *Authority* to impose additional requirements, procedures, or standards under this Section 4.10.2 on another *User* in order to monitor or assess compliance with the *KNTGC* by that *User*. When such a request is made, the *Authority* may but is not required to impose the additional requirements, procedures, or standards. A decision by the *Authority* to impose additional requirements, procedures or standards is a reviewable decision. If the *Authority* decides to impose additional requirements, procedures, or standards, the *Authority* may determine the allocation of costs of any additional compliance monitoring undertaken between the relevant *Users*. *Users* shall pay such costs as allocated. In the absence of such allocation, the *User* subject to the additional requirements, procedures, or standards will bear his own costs of compliance.

(h) The *Authority* shall develop and implement guidelines in accordance with the *KNTGC* consultation procedures governing the exercise of the powers conferred on it by Section 4.10.2(g) which guidelines shall set out the matters to which the *Authority* shall have regard prior to deciding the allocation of costs of any additional requirements, procedures or standards imposed pursuant to Section 4.10.2(g) between the relevant *Users*.

4.10.3 Use of Information

(a) Subject to confidentiality obligations set out in the *Confidentiality* sections of the *KNTGC,* the *Authority* is entitled to use any data or information obtained as a result of any monitoring requirements imposed under Section 4.15.2 in pursuance of any of the *Authority's* powers or functions under the *KNTGC.* Without limitation, the *Authority* may use any such information in connection with or to initiate:

   (i) A process to change or revise the *KNTGC;* or

   (ii) An investigation under the *KNTGC.*

(b) A *User* may claim that the information provided to the *Authority* is confidential in nature to the *User* or that the *User* is under an obligation to another person to maintain the confidentiality of all or part of the information. Notwithstanding that the *Authority* may consider the claim by the *User* to be reasonable, if the *Authority* considers that its reporting obligations set out in the *KNTGC* make the disclosure of the information necessary or desirable, the *Authority* may disclose the information. In doing so, the *Authority* shall use all reasonable endeavours to ensure the information is disclosed only in a manner and to the extent that, as far as practicable, protects the confidential nature of the information and in no way is the *Authority* to be liable for publishing or disclosing any information under this Section 4.15.3.

(c) Prior to disclosing in accordance with Section 4.15.3(b) information which a *User* claims is confidential, the *Authority* shall first notify that *User* as soon as practicable after the *Authority* has made the decision to disclose the information.

(d) Any decision by the *Authority* under Section 4.15.3(b) to disclose information that is claimed by a *User* to be confidential is a reviewable decision and the *Authority* shall not disclose the information until twenty-eight (28) days after it has provided written notice to the relevant *User* that it intends to disclose the information.

4.10.4 Reporting

(a) Not later than 31st December in each calendar year, the *Authority* shall prepare and give an annual report for the previous *Financial Year* to all *Users* and interested parties. The annual report shall include:

(i) The *Authority*'s assessment of the extent to which the operation of the *KNTGC* during that period met the *KNTGC* objectives and of the strategic development of the *KNTGC* to meet industry objectives;

(ii) A report on the matters set out in the Operations Chapter concerning the *Kenya National TSO* use of powers of direction in relation to *Power System Security* granted to him under the Operations Chapter;

(iii) A summary of, and reasons for, any changes to the *KNTGC;*

(iv) A summary of identified material breaches of the *KNTGC* and the actions taken in response, including particulars of any sanctions imposed;

(v) A summary of any disputes referred to the *Authority* or involving the *Authority* as a *Party*;

(vi) A summary of material matters in relation to the dispute resolution under the *KNTGC* (without identifying the parties); and

(vii) The *Authority's* assessment of the matters set out in Section 4.10.1(b) which it is required to monitor.

(b) In addition to the annual report described in Section 4.10.4(a), the *Authority* may, if it considers it appropriate, provide an interim report to *Users* and interested parties on any one or more of the matters that should be contained in the annual report.

5 PLANNING

5.1 EAPP IC REQUIREMENTS

5.1.1 Introduction

The Planning Chapter (PC) specifies the minimum technical and design criteria, principles and procedures:

(a) To be used within *EAPP* in the planning and in the medium and long-term development of the *EAPP Interconnected Transmission System*;

(b) To be taken into account by *Member Utilities* on a coordinated basis, and

(c) To specify the planning data required to be exchanged by *Member Utilities* and the *EAPP Sub-Committee on Planning* to enable the *EAPP Interconnected Transmission System* to be planned in accordance with the planning standards.

The PC specifies the requirements for the interchange of information between *EAPP Sub-Committee on Planning* and individual *TSOs.* This information is required to enable *EAPP Sub-Committee on Planning* and *TSOs* to take due account of developments, new connection sites or the modification of existing connection sites in a *National System* or new, or the modification of, connections with *External Systems*, including changes in factors such as demand, generation, new technology, reliability and environmental requirements that may also have an impact on the planning and operation of the *EAPP Interconnected Transmission System*.

All parts of the *EAPP Interconnected Transmission System* shall be designed so that the demand for electricity can be met reliably at the lowest cost. This means that the *EAPP Interconnected Transmission System* shall be planned, built, and operated so that sufficient transmission capacity will be available to utilise the generation capacity and to meet the needs of *Customer*s in an economic way.

The long-term economic design of the *EAPP Interconnected Transmission System* aims at a balance between investments and the cost of maintenance, operation, and supply interruptions, taking into account environmental and other limitations. Flexible solutions which take into account future uncertainties, such as generation limitations, new generation technologies, uncertain load development and technical development, should be selected.

5.1.2 Objectives

The objectives of the PC are to provide for:

(a) Coordination by the *EAPP Sub-Committee on Planning* of any proposed development or reinforcement of a *National System* or construction of new or modification of interconnections with *External Systems* to ensure that the reliability and security of the *EAPP Interconnected Transmission System* is not compromised;

(b) Cooperation between the *TSOs* in the planning and procurement of new generation capacity at lowest overall cost, taking into account environmental considerations, and

(c) Submission of sufficient information to enable a *TSO* to optimise the planning and development of its *National System* including the use of available transmission capacity on the *EAPP Interconnected Transmission System*.

5.1.3 Scope

The PC applies to the *EAPP Sub-committee on Planning* and to the *TSOs*. The *TSOs* are responsible for the collection of information from *Users* connected to their *National System* and for providing any relevant information required by the PC to the *EAPP Sub-committee on Planning*.

Those *TSOs* with connections to *External Systems* shall ensure that the supply of data required under the PC should be contemplated in the *Interconnection Agreement* with the *External System* seeking a new or modified interconnection.

5.1.4 Principles of the Planning Chapter

These principles apply to the overall planning of the *EAPP Interconnected Transmission System*. The planning principles are concerned with planning of the interconnection between *National Systems,* connections with *External Systems* and with those facilities within *National Systems* which have, or could have, an impact on the reliability of the *EAPP Interconnected Transmission System*.

The principles should also be applied in the planning of *National Systems* to ensure that the reliability criteria can be met. The principles, however, do not apply to local supply reliability and other local considerations which are the subject of National Grid Codes or equivalent documents.

The reliability level for the *EAPP Interconnected Transmission System* is defined by a set of minimum criteria in the PC together with the performance characteristics and requirements set out in the Connections Chapter, which must both be met when designing developments, expansions, and reinforcements of both *EAPP Interconnected Transmission System* and *National Systems*. The criteria are based on a balance between the probability of contingencies and their consequences.

Reliable transmission capacity can be achieved by specifying standards for primary, protection, and auxiliary equipment as well as by reserve capacity and other operational resources as set out in the Operations Chapters.

5.1.5 Reliability Criteria

All *Plant* and *Apparatus* of the *EAPP Interconnected Transmission System* shall operate within normal capacity ratings, thermal loading and voltage limits under steady-state conditions as set out in the Connections Chapter. The *EAPP Interconnected Transmission System* shall be able to supply all loads within the emergency limits for bus voltages and *Plant* and *Apparatus* loadings during the *Outage* of any line or transformer (N-1 criteria).

The security and reliability of the *EAPP Interconnected Transmission System* shall not be compromised by the loss of any single power system element such as a *Generating Unit*, transmission circuit, section of busbar, transformer or reactive compensation equipment.

The loss of a single element shall not cause:

(a) Any violation of the normal operational limits such as voltage, frequency or *Plant* and *Apparatus* loading which would jeopardise the safety and reliability of the *EAPP Interconnected Transmission System* or would cause overloading of *Plant* or *Apparatus*;

(b) Islanding of any part of the *EAPP Interconnected Transmission System*;

(c) Loss of stability of the *EAPP Interconnected Transmission System*; or

(d) Cascading *Outages* of other elements as a result of exceeding operational security limits as set out in Chapter 9 (Operations Code No. 2 – Operational Security).

These criteria are not applicable to areas connected by radial lines to a *National System* where loss of load and any local generation may be acceptable.

The N-1 criterion may be assured in a *National System* with the support of another interconnected *National System*, subject to the prior agreement of the respective *TSO*s.

The planning criteria for dynamic security are defined such that the *EAPP Interconnected Transmission System* shall remain stable following a single *Contingency*. The *EAPP Interconnected Transmission System* is able to remain stable in some cases following a fault without the *Outage* of any transmission element by a successful auto-reclosing. If the attempt of auto-reclosing fails, the fault shall be cleared by tripping the faulted element.

5.1.6 Planning Process

The horizon for the planning of the *EAPP Interconnected Transmission System* extends over ten (10) years. The process has two elements:

(a) A forecast, the *Power Balance Statement*, by *TSO*s for each *National System* of their expected demand and generation over the planning horizon. This forecast will define the requirements for generation support from the *EAPP Interconnected Transmission System* for individual *National Systems*, and

(b) An assessment, the *Transmission System Capability Statement* by *EAPP Sub-committee on Planning* and *TSOs* of the capability of the *EAPP Interconnected Transmission System* to support the required energy flows across both *National Systems* and cross-border interconnections.

5.1.6.1 Power Balance Statement

*TSO*s will prepare and submit to the *EAPP Sub-committee on Planning* the *Power Balance Statement*. This report will be submitted by 30th September annually showing in respect of the ten (10) succeeding calendar years:

(a) The projection of the seasonal maximum and minimum demand for electricity in each *National System* and the corresponding energy requirements for each year across the study period. These forecasts will correspond to certain reference dates to be defined by the *EAPP Sub-committee on Planning*;

(b) The amount and nature of generation capacity currently available to meet the demand and any anticipated restrictions in the production of energy;

(c) The amount of generation capacity it expects will be required to ensure that *Operating Margins* are achieved;

(d) Details of plans for building additional *Generating Units* including upgrades of existing generation capacity;

(e) The amount and nature of demand to be met by other *EAPP Member Countries* using transmission capacity available on the *EAPP Interconnected Transmission System*, and

(f) The power transfers anticipated with *External Systems*.

The difference between available generating capacity and demand at the reference dates is called the *Remaining Capacity* and is calculated under normal climatic conditions. This *Remaining Capacity* represents the reserves available which can be used to cover demand above forecast or *Generating Unit*

Outages greater than expected. The *Remaining Capacity* can be positive with export potential or negative where the lack of capacity signals a need for imports.

The *EAPP* Sub-Committee on Planning shall produce a *Power Balance Statement* for the *EAPP* Interconnected Transmission System based on the individual *TSOs*' *Power Balance Statement*s.

5.1.6.2 Transmission System Capability Statement

Once the *Power Balance Statement* has identified the ability of each *TSO* to cover its internal demand with the available national generation capacity, a transmission adequacy assessment shall be carried out by each *TSO* in conjunction with the *EAPP Sub-Committee on Planning.* This assessment will determine the capability of the *National System* to support the required energy flows across both the *National System* and cross-border connections.

Based on the transmission adequacy assessment carried out by each *TSO*, the *EAPP Sub-Committee on Planning* will produce a *Transmission System Capability Statement* for the *EAPP Interconnected Transmission System*. This *Transmission System Capability Statement* is focused on the cross-border connections and those *TSO's National Systems* which have a direct effect on the cross-border exchanges.

In producing the *Transmission System Capability Statement,* the *EAPP Sub-Committee on Planning* shall consider various scenarios for interchanges, demands and generation. Sensitivity analysis shall be carried out taking into account such parameters as hydrological conditions and fuel price variations.

The *EAPP Sub-Committee on Planning* may also consider the use of *Remedial Action Schemes (RAS),* in which automatic control equipment disconnects or otherwise controls generation, demand, or network elements other than for faults. Such *RAS* are used to enhance transmission capacity at the expense of reliability and may only be used following specific agreement between the *EAPP Steering Committee* and the affected *TSO*.

The *EAPP Sub-Committee on Planning* will determine the form and content of the *Transmission System Capability Statement* to be issued each year and shall publish it on the *EAPP* Website.

5.1.7 EAPP Power System Modeling

In order to produce the *EAPP Transmission System Capability Statement,* it will be necessary to carry out system analysis, including steady-state and dynamic simulations of the *EAPP Interconnected Transmission System*. This system analysis is required in order to assess the reliability of the *EAPP Interconnected Transmission System* to meet the forecast demand and determine the need for system enhancements or reinforcements.

These system studies will be carried out by both the *EAPP Sub-Committee on Planning* and the *TSO*s and shall be performed using a common set of principles and a common database. To achieve this, the *EAPP Sub-Committee on Planning* shall establish a set of common objectives for the development and submission of system data for *EAPP* power system modelling. The data shall include sufficient detail to ensure that system contingencies, steady-state, transient and dynamic analyses can be simulated. The data required for system studies is set out in the Data Exchange Chapter.

5.1.8 Responsibilities

EAPP Sub-Committee on Planning in conjunction with the *TSO*s shall identify the scope and specify the data required for reliability analysis and the procedures for data reporting. These requirements and procedures should be periodically reviewed, documented, and published for the *EAPP Interconnected Transmission System* at least every five (5) years.

Each *TSO* shall provide accurate and appropriate equipment characteristics and power system data for modelling and simulation purposes as required by the *EAPP Sub-Committee on Planning*.

5.1.9 Planning Data Confidentiality

System planning data shall be treated as non-confidential when the *EAPP Sub-Committees on Planning and Operations* and *TSOs* use such data:

(a) In the preparation of forecasts, *Power Balance Statement*s and Transmission System Capability Statements;

(b) For the planning of the *EAPP Interconnected Transmission System*;

(c) To consider a Connection Application or provide advice to a *User*;

(d) Under the terms of an *Interconnection Agreement* with an *External System*.

5.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

All the requirements presented in Section 5.1 *EAPP IC* Requirements shall apply in this Section5.2 and in all other places in this Planning Chapter.

5.2.1 Introduction

Section 5.2 specifies the criteria and procedures to be applied by Kenya's *Planning and Development Organisation(s)* in the planning and development of the *Kenya National Transmission System.* It furthermore provides for accountability for *KNTS* planning and development and sets the required standards and targets. It also specifies the reciprocal obligations and interactions between *Users*.

5.2.2 Transmission System Planning and Development

The *KNTS* planning and development shall be in accordance with the prevailing legal and regulatory framework, as being implemented from time to time. The Act requires each licensee to develop and submit to the Cabinet Secretary plans for provision of Energy Serivces in accordance with its mandate which shall be consolidated into a INEP to be reviewed after every 3 years.

The development and update of the *KNTS planning* may occur for a number of reasons, including but not limited to:

(a) Changes to *User requirements* or networks

(b) The introduction of a new transmission substation or *Connection Point* or the modification of an existing connection between a *User and* the *KNTS*

(c) The cumulative effect of a number of developments as referred to above

(d) The need to reconfigure, decommission or optimise parts of the existing network.

The development of the *KNTS* may include work involving transformers, breakers, switches, and other equipment connected to the *KNTS.*

The time required for the planning and development of the *KNTS* will depend on the type and extent of the necessary reinforcement and/or extension work, the need or otherwise for statutory planning consent, the associated possibility of the need for public participation and the degree of complexity involved in undertaking the new work while maintaining satisfactory security and quality of supply on the existing *KNTS*.

5.2.2.1 Planning Process

Kenya's *Planning and Development Organisation(s)* shall follow a planning process divided into major activities as follows:

(a) Identification of the problem

(b) Formulation of alternative options to meet this need

(c) Study of these options to ensure compliance with agreed technical limits and justifiable reliability and quality of supply standards

(d) Costing of these options on the basis of approved procedures

(e) Determination of the preferred option

(f) Building of a business case for the preferred option using the approved justification criteria

(g) Request for approval of the preferred option and initiation of execution.

5.2.2.2 Identification of Need for Transmission System Development

(a) *The INEP Committee shall* review data from all relevant sources, including specific *Customer* information, system performance statistics, *KNTS* load forecast, and government and *Customer* development plans to establish the need for network strengthening.

(b) The needs shall be determined through the modelling of the *KNTS* over a ten-year term, utilising reasonable load and generation forecasts and equipment performance scenarios. Studies for purposes of determining connection charges payable by *Customer*s may cover a shorter period if appropriate.

(c) The *INEP Committee shall* annually conduct a planning review with parties to co-ordinate *KNTS* and the *Kenya National Distribution System (KNDS).*

5.2.3 Demand Forecast

(a) The *SO* in consultation with the *TNSPs* and *DNSPs* shall annually produce a *KNTS* demand forecast for the next ten years by the end of August of each year.

(b) The *KNTS* demand forecast shall be determined for each point of supply. Generation and import capacity plans shall be used to obtain the annual generation patterns.

(c) To forecast the maximum demand (MW) for each transmission substation, the *SO shall* use Distribution *Licensee and End-user load* forecasts.

(d) The load forecast shall be adjusted at various levels (making use of diversity factors determined from measurements and calculations) to bring it into line with the higher-level data.

(e) All *Distribution Licensees* and *End-users* shall supply their ten-year-ahead load forecast data to *the SO* as detailed in the Information Exchange Chapter annually, by the end of July. All *Customer*s shall inform their *TNSP* of any changes in excess of 50 MW to this forecast when this information becomes available.

5.2.4 Transmission System Development Plan

The *TNSP shall* in accordance with the INEP Regulations submit plans indicating the major capital investments planned (but not yet necessarily approved) of the Cabinet Secretary. The plan shall include at least

(a) The acquisition of wayleaves for strategic purposes

(b) A list of planned investments including costs

(c) Diagrams displaying the planned changes to the *KNTS*

(d) An indication of the impact on *Customer*s in terms of service quality and cost

(e) Opportunities to render *Ancillary Services* for the mitigation of network constraints.

(f) Any other information as specified by the *Authority* from time to time.

The *KNTS* development plan shall be based on all *Customer* requests received at that time, as well as the *TNSP* initiated projects based on load forecasts and changes in generation.

The *TNSP* shall engage in a consultative process with *Users* and the *Authority* on the *KNTS* development plan. The consultation process shall include:

(a) An annual public forum to disseminate the intended *KNTS* development plan

(b) Regular interfacing and joint planning with *Users* regarding *KNTS* development.

*Dispute*s arising from the above process shall be decided in terms of the dispute resolution mechanism in Chapter 4 (Governance).

5.2.4.1 Development Assessment Reports

Before any development of the network proceeds, *TNSP shall* compile a detailed development assessment report. The report shall be used as the basis for the investment decision and shall as a minimum contain the following elements:

(a) A description of the problem/request and the objectives to be achieved

(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 alternative selected in accordance with the approved investment criteria, with consideration of relevant scenarios and appropriate risk analysis

(d) Diagrams, sketches and relevant technical study results

(e) Clear statement and analysis of the assumptions used

The report shall be submitted to the Ministry of Energy.

5.2.5 Technical Limits and Targets for Long Term Planning Purposes

(a) The planning limits, targets and criteria form the basis for evaluation of options for the long-term development of the *KNTS*.

(b) The limits and targets against which proposed options are checked by the TNSP shall include technical and statutory limits that must be observed and other targets that indicate that the systemis reaching a point where power transfer problems may occur. If planning limits are not attained, alternative options shall be evaluated.

5.2.5.1 Voltage Limits and Targets

(a) Technical and statutory limits are presented in Table 5-1.

(b) Standard voltage levels are given in Table 5-2.

(c) Table 5-3 has target voltages for planning purposes at transmission voltages.

Table 5-1 Voltage Limits for Planning Purposes

Requirement	Value
Nominal continuous operating voltage on any bus for which equipment is designed	U_n
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed Um, the highest voltage used at sending end busbars in planning studies should not exceed 0.98 Um	U_m
Minimum voltage on Point of Common Coupling during motor starting	0.85 U_n
Maximum voltage change when switching, capacitors, reactors, etc. (system healthy)	0.03 U_n (healthy)
Statutory voltage on bus supplying *Customer* for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	$U_n \pm 5\%$

Table 5-2 Standard Voltage Levels

Un (kV)	Um (kV)	(Um-Un)/Un, %
500	525	5.00
400	420	5.00
220	245	11.36
132	145	9.85

Table 5-3 Target Voltages for Planning Purposes at Transmission Voltages

<table>
<tr><th colspan="2">Requirement</th><th>Value</th></tr>
<tr><td colspan="2">Minimum steady state voltage at bus supplying Customer load unless otherwise specified in the Customer's supply agreement</td><td>0.95 U_n</td></tr>
<tr><td rowspan="3">Minimum and maximum steady state voltage on any controlled bus, unless otherwise specified in the Customer supply agreement:</td><td>System healthy:</td><td>0.95U_n to 1.05U_n</td></tr>
<tr><td>After designed contingency (before control actions):</td><td>0.90 U_n to 0.98 U_m</td></tr>
<tr><td>After control actions:</td><td>0.95 $U_n$to 1.05 U_n</td></tr>
<tr><td colspan="2">Maximum steady state voltage at bus supplying Customer load unless otherwise specified in the Customer supply agreement</td><td>1.05 U_n</td></tr>
<tr><td rowspan="2">Maximum harmonic voltage caused by Customer at the Point of Common Coupling (PCC)</td><td>Individual harmonic:</td><td>0.01 U_n</td></tr>
<tr><td>Total (square root of sum of squares):</td><td>0.03 U_n</td></tr>
<tr><td rowspan="2">Maximum negative sequence voltage caused by Customer at PCC:</td><td>Continuous single-phase load connected phase-to-phase:</td><td>0.01 U_n</td></tr>
<tr><td>Multiple, continuously varying, single-phase loads:</td><td>0.015 U_n</td></tr>
</table>

Requirement	Value
Harmonic voltage limits:	As defined in KS IEC 61000
Maximum voltage change owing to load varying N times per hour:	$(4.5 \log_{10}N)\%$ of U_n
Maximum voltage decrease for a 5% (MW) load increase at receiving end of system (without adjustment):	0.05 U_n

5.2.5.2 Other Targets for Long-term Planning Purposes

Transmission Lines

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

Transformers

Standard transformer ratings shall be determined by the TNSP and Generators and updated from time to time using the standards by the Kenya Bureau of Standards or any international standard approved by the *Kenya Bureau of Standards.* 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 adding extra transformers.

Series Capacitors

The *TNSP* shall assure the maximum steady state current should not exceed the rated current of the series capacitor. The internationally accepted standard's cyclic overload capabilities are for operational use only, to allow time to reduce loading to within the rated current without damaging the series capacitor.

Shunt Reactive Compensation

The *TNSP* shall assure that shunt capacitors can operate at 30% above their nominal rated current at U_n to allow for harmonics and voltages up to U_m.

Circuit Breakers

The Users of KNTS shall specify and install circuit breakers as directed by the *SO* that meet system fault levels and other conditions considered important for the safe and secure operation of the *KNTS*. Ratings are to be according to international circuit breaker standards such as those of the *IEC*.

5.2.5.3 Reliability Criteria for Long-term Planning Purposes

The Ministry of Energy in consultation with the relevant stakeholders *shall* formulate long-term plans for development of the *KNTS* on the basis of the justifiable redundancy. With one line or transformer or reactive compensation device out of service (N-1), it shall be possible to supply the entire load under all credible system operating conditions. The loss of a single element shall not cause:

(a) Any violation of the normal operational limits such as voltage, frequency or Plant and Apparatus loading which would jeopardise the safety and reliability of the *Kenya National Transmission System* or would cause overloading of Plant or Apparatus;

(b) Islanding of any part of the *Kenya National Transmission System*;

(c) Loss of stability of the *Kenya National Transmission System*; or

(d) Cascading *Outages* of other elements as a result of exceeding operational security limits as set out in Chapter 9 (Operations Code No. 2 – Operational Security).

Investment in the *KNTS* to satisfy the minimum (N-1) redundancy requirement shall be on a deterministic basis, with no financial justification required.

An unfirm transmission infeed to an underlying *Distribution Network* is acceptable, as long as the underlying *Distribution Network* can supply the entire load without load shedding or load curtailment and without violating the technical planning limits on either the *Transmission* or *Distribution*s ystems on loss of the transmission infeed.

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.

The Ministry *shall* in planning the *KNTS* minimise as far as practicable the risk of common cause failure of two or more items of plant (e.g. loss of two or more lines in a common wayleave or on a double circuit or multi-circuit structure), and insofar as such risk is unavoidable, shall take reasonable measures to mitigate such risk.

Additional equipment shall be provided if it can be justified to be included in the rate base in terms of the Least Economic Cost and/or Cost Reduction Investment as defined in this chapter or the cost is recoverable from a *Customer* or group of *Customer*s in accordance with the description under Strategic Investments in this chapter.

5.2.5.4 Contingency Criteria for Long-term Planning Purposes

(a) A system meeting the N-1 (or N-2) *Contingency* criterion must comply with all relevant limits outlined in Tables 5-1, 5-2 and 5-3 (voltage limits) and the applicable current limits, under all credible system conditions.

(b) For contingencies under various loading conditions it shall be assumed that appropriate, normally used *Generating Plants* are in service to meet the load and provide spinning reserve. For the more probable N-1 network *Contingency*, the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable N-2 network *Contingency* an average pattern shall be used. Refer to the load and generation assumptions for load flow studies in the Transmission System Development section of this chapter.

(c) The generation assumptions for the N-1 network *Contingencies* do not affect the final justification to proceed with investments, but merely define what is meant by the statement that the system has been designed to meet an N-1 or N-2 *Contingency.*

5.2.6 Integration of Generating Plants

When the integration of *Generating Plants* is planned, the following network redundancy criteria shall apply:

(a) *Generating Plants* of less than 100 MW

(i) With all connecting lines in service, it shall be possible to transmit the total output of the Generating *Plant* to the system for any system load condition. If the local area depends on the Generating *Plant* 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) *Generating Plants* of more than 100 MW

(i) With one connecting line out of service (N-1), it shall be possible to transmit the total output of the Generating *Plant* to the system for any system load condition.

(ii) Smallest unit installed at the *Generating Plant* shall only include units that are directly connected to the transmission system and are centrally dispatched.

(c) Transient *stability* shall be retained for the following conditions:

(i) A three-phase line or busbar fault, cleared in normal protection times, with the system healthy and the most onerous *Generating Plant* loading condition; or

(ii) A single-phase fault cleared in "bus strip" times, with the system healthy and the most onerous *Generating Plant* loading condition; or

(iii) A single-phase fault, cleared in normal protection times, with any one line out of service and the *Generating Plant* loaded to average availability.

(d) The cost of ensuring transient stability shall be carried by the *Generation Licensee* if the optimum solution, as determined by the *SO*, results in *Generating Plant* equipment being installed. In other cases, the *TNSP* shall bear the costs and recover these as per the approved *Tariff* methodology.

(e) *Busbar* layouts shall allow for selection to alternative busbars. In addition, feeders must have the ability to go onto bypass.

(f) The busbar layout shall ensure that not more than 100 MW of generation is lost as a result of a single *Contingency.*

(g) To *enable* the *SO* to successfully integrate new *Generating Plants,* detailed information is required for each *Generating Plant*, as described in the Information Exchange Chapter.

5.2.7 Criteria for Network Investments

The *TNSP shall* invest in the *KNTS* when the required development meets the technical and investment criteria specified in this section, or if the investment is in response to a *Customer* request for transmission service and the cost is recoverable from the *Customer* or group of *Customer*s concerned in accordance with the *Authority* approved development cost recovery guidelines.

The TNSP *shall* communicate all impacts timeously such that provision can be made for budgeting and implementation of related changes at the *Customer* installation.

Any one of the investment criteria below, each applicable under different circumstances, can be applied.

Calculations will assume a typical project life expectancy of 25 years, except where otherwise dictated by plant life or project life expectancy.

The following key economic parameters shall have *Authority* approved process of establishment:

(a) Discount rate

(b) Cost of unserved energy (COUE)

(c) Other parameters as specified by the *Authority* from time to time.

5.2.7.1 Least Economic Cost Criteria

(a) These criteria shall apply under the following circumstances:

(i) When new *Customer*s are to be connected

(ii) When investments are made in terms of improved supply reliability and/or quality to attain the limits or targets determined in the section Technical Limits and Targets for Long Term Planning Purposes in this chapter.

(iii) To determine and/or verify the desired level of network or equipment redundancy

(b) The methodology for determining the value of load or generation in neighbouring countries shall be approved by the *Authority*. The methodology requires the cost of poor service to be determined. These include the cost of:

(i) Interruptions

(ii) Load shedding

(iii) Network constraints

(iv) Voltage dips, surges, flickers, and harmonic distortion.

(c) The least-cost investment criterion equation to be satisfied can be expressed as follows: "Value of improved Quality of Service (QOS) to Customers > cost to the TNSP to provide improved QOS"

(d) From this equation it is evident that if the value of the improved *QOS* to the *Customer* is less than the cost to the *TNSP*, then the *TNSP* should not invest in the proposed project(s). The investment decision shall then be delayed such that optimised economic benefit can be derived.

(e) This implies that for the criteria to be satisfied: "*Cost of Unserved Energy (COUE)* annual value (S/kWh) x annual reduction in *Expected Unserved Energy* (*EUE)* to *Customers*(kWh) > annual cost to the *TNSP* to reduce *EUE*"

(f) The reduction in *EUE* shall be calculated on a probabilistic basis by a methodology approved by the *Authority.*

(g) COUE is a function of the types of loads, the proportion of the total load contributed by each different 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 *Customer*s, the availability of *Customer* backup generation and many other factors.

5.2.7.2 Cost Reduction Investments

Proposed expenditure that is intended to reduce *TNSP*'s costs (e.g. shunt capacitor installations, telecommunication projects and equipment replacement that reduce costs, external telephone service expenses and maintenance costs respectively) or the cost of losses or other *Ancillary Services* should be evaluated in the following manner:

(a) First, it is necessary to calculate the *Net Present Value (NPV)* of the proposed investment using *Discounted Cash Flow (DCF)* methods. This shall be done by considering all cost reductions (e.g. savings in system losses) as positive cash flows, off-setting the required capital expenditure. Once again, 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. As before, a resulting positive *NPV* indicates that the investment is justified over the expected life of the proposed new asset.

(b) However, a positive *NPV* does not always indicate the optimal timing for the investment. For this reason, the second portion of the cost reduction analysis is necessary – ascertaining whether the annual extra costs incurred by the *TNSP* for owning (levelised) and operating the proposed asset is less than all cost reductions resulting from the new asset in the first year that it is in commission.

5.2.7.3 Statutory Investments

This category of projects comprises investments that the *TNSP* is legally required to make, irrespective of whether any economic benefit is likely to accrue, including the following:

(a) Investments formally requested in terms of published government policy
(b) Projects necessary to meet environmental legislation
(c) Expenditure to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity transmission and the safety of the general public
(d) Expenditure required to comply with other applicable legislation
(e) Expenditure required to comply with court orders
(f) Possible compulsory contractual commitments

The results of the least economic cost and/or cost reduction analyses should still be documented to demonstrate the financial impact on the business.

5.2.7.4 Strategic Investments

This category of investments comprises discretionary investments made by the *TNSP* to ensure the long-term sustainability of the *TNSP*, including:

(a) Site and wayleave acquisition
(b) Expenditure, except for network expansion, required to ensure the longer term sustainability of the *TNSP* which cannot be justified in terms of the Least Economic Cost and Cost Reduction Investment Criteria as defined in this chapter or recovered from a *Customer* or group of *Customer*s as a connection charge as specified in Strategic Investments in this chapter. In this case, the motivation as to why the investment is genuinely needed to ensure the longer term sustainability of the *TNSP* must be clearly stated, and the results of the least economic cost and/or cost reduction analyses must be documented, or reasons given why such analysis is not possible or practical. These shall include purchasing of capital spares to minimise *Outage* duration following major plant failure, purchase of specialised vehicles and equipment to transport transformers and reactors, or implementation of industry restructuring.
(c) Asset replacements forming part of an asset lifecycle management plan compiled in accordance with asset management practices approved by the *Authority*.
(d) Network expansion projects which cannot be justified in terms of N-1 redundancy or cannot be recovered from a *Customer* or group of *Customer*s as a connection charge or a Strategic Investment, as defined in this chapter, but will provide flexibility, and avoid network redundancy in the future.
(e) Any other investments considered by the *TNSP* to be justified as strategic on grounds other than those covered in this section are to be submitted to the *Authority* for consideration on a case by case basis prior to commitment to expenditure. The results of the least economic cost and/or cost reduction analyses should still be documented to demonstrate the financial impact on the business.

5.2.8 Mitigation of Network Constraints

Network constraints (“congestion”) shall be regularly reviewed by *the SO* and reported to the *Authority and the Ministry.* Economically optimal plans shall be put in place around each constraint, which may involve investment, the purchase of the constrained generation, ancillary service or other solutions.

5.2.8.1 Special Customer Requirements for Increased Reliability

Where a *Customer* requires a more reliable or safer connection than the one provided for by the *TNSP* and the *Customer* is willing to pay the total cost of providing the increased reliability in the form of an additional connection charge, the *TNSP* under the direction of the *SO shall* meet the requirements at the lowest overall cost.

6 CONNECTIONS

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall apply.

6.1 EAPP IC REQUIREMENTS

6.1.1 Introduction

The Connections Chapter (CC) specifies the minimum technical, design, and operational criteria of *Plant* and *Apparatus,* which must be complied with by the *TSOs* and *Users* at the *Connection Point*, in order to maintain secure and stable operation of the *EAPP Interconnected Transmission System.*

Respective National legislation and codes may lay down local requirements. These local requirements should observe the minimum standards in this CC to avoid adverse effects on the *EAPP Interconnected Transmission System,* which may affect power interconnection security and quality of supply to other *Parties* or increase fault levels beyond the capabilities of existing *Connection Points*.

The provisions of the CC shall apply to all connections to the *EAPP Interconnected Transmission System:*

(a) Existing at the date when this chapter comes into effect, or

(b) As established or modified thereafter.

6.1.2 Objective

The CC is designed to ensure:

(a) That a new or modified connection shall not impose adverse effects upon the *EAPP Interconnected Transmission System* nor will it be subject itself to unacceptable effects by its connection to the *EAPP Interconnected Transmission System;*

(b) That the basic rules for connection treat all *TSOs* and *Users* in a non-discriminatory manner, and

(c) Ongoing compliance with the technical and operational requirements of the Interconnection Code to facilitate operational management of the *EAPP Interconnected Transmission System.*

6.1.3 Scope

The CC applies to *TSOs* and to all *Users* connected or seeking connection to the *EAPP Interconnected Transmission System*.

6.1.4 Transmission System Performance Characteristics

6.1.4.1 Frequency

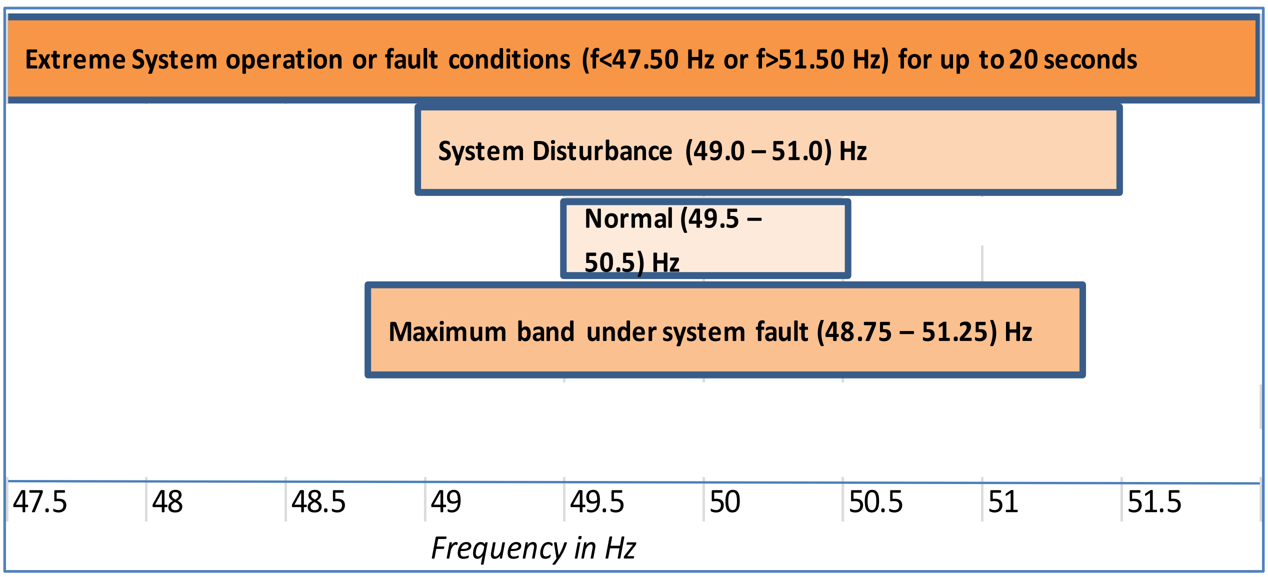
Frequency is the one parameter common to all members of a synchronous electric power system, and an accepted indicator of that system's ability to balance resources and demandas well as to manage disturbances.

Under normal operation, the frequency of the *EAPP Interconnected Transmission System* shall be nominally 50 Hz and shall be controlled between 49.5 Hz and 50.5 Hz (±1%) unless exceptional circumstances prevail. Following a system disturbance such as a load variation, the frequency band is extended to 49.0–51.0 Hz (±2%). If a major *Generating Unit* is tripped, a major transmission element fails or large loads are suddenly disconnected, the maximum frequency band becomes 48.75–51.25 Hz (±2.5%). 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%) for up to 20 seconds, and then extreme measures should be taken to restore the system. These figures are summarised in Table 6-1 and graphically represented in Figure 6-1.

Table 6-1: Frequency Limits in the EAPP Interconnected Transmission System

Operating Conditions	Frequency Limits
Under Normal Operation	49.50Hz to 50.50Hz
Under System Disturbance	49.00 Hz to 51.00 Hz
Maximum band under system fault	48.75 Hz to 51.25 Hz
Under extreme System operation or fault conditions	f<47.50 Hz or f>51.50 Hz for up to 20 seconds

Figure 6-1: Frequency Limits in the EAPP Interconnected Transmission System



6.1.4.2 Voltage

Steady State Voltage

Voltage conditions in a high voltage grid are directly related to the *Reactive Power* balance at the system nodes. Unlike *Active Power*, *Reactive Power* cannot be transmitted over long distances, since the transmission of *Reactive Power* generates an additional demand for *Reactive Power* in the system components, thereby causing voltage drops. In order to obtain an acceptable voltage level, *Reactive Power* generation and consumption have to be situated as close to each other as possible to avoid excessive *Reactive Power* transmission.

The voltages on the *EAPP Interconnected Transmission System* shall normally be maintained within the limits set out below:

(a) Operating voltage range of 0.95 to 1.05 per unit in steady state normal conditions for nominal voltages used in the *EAPP Interconnected Transmission System* namely 500 kV, 400 kV, 230 KV, 220 kV, 132 kV, 110 kV and 66 kV,

(b) Operating voltage range of 0.90 to 1.10 per unit after any single *Contingency*, and

(c) Operating voltage range of 0.85 to 1.20 per unit after any multiple *Contingency* or severe system stress.

Table 6-2: Steady State Voltage Limits

Operating Conditions	Voltage Limits
Normal	0.95 - 1.05
Contingency (N-1)	0.90 – 1.10
Multiple Contingency	0.85 – 1.20

TSOs shall endeavour to ensure that *Users* comply with lagging power factors of 1.0 or less during periods of minimum demand and 0.95 or higher during peak and shoulder hours.

Transient Voltage

Transient over-voltages can occur on the *EAPP Interconnected Transmission System* as a result of lightning surges or the switching of long transmission lines or cables. The insulation level of all *Plant* and *Apparatus* at the *Connection Point* must be coordinated to take account of these transient over-voltages. The insulation levels for equipment shown in Table 6-3 below are based on *IEC* 60071-1:

Table 6-3: Permissible Transient Voltages

Nominal Voltage Or Rated Voltage	Used for Transmission in Countries	Highest Operating Voltage On Equipment	Withstand Voltage (kV) for Lightning Surge (LIWL)	Withstand Voltage For Switching Surge (*SIWL*)	50 Hz, 1 Min Withstand Voltage (kV)
66 kV	Ethiopia, Sudan, Tanzania, Kenya	72.5 kV	325	N/A	140
110 kV	Burundi, DRC, Rwanda, Sudan	123 kV	550	N/A	230
132 kV	Ethiopia, Kenya, Tanzania	145 kV	650	N/A	275
220 kV	Egypt, Kenya, Sudan, Tanzania	245 kV	950	N/A	395
230 kV	Ethiopia	245 kV	1050	N/A	N/A
400 kV	Ethiopia	420 kV	1050 – 1425	850/950/1050	N/A
500 kV	Egypt	550 kV	1175 – 1550	950/1050/1175	N/A

The lowest operating voltages at each voltage level depend on the local conditions. The lowest values are reached during operational disturbances and are usually not lower than 0.9 per unit.

Voltage Dips

A voltage reduction with duration of 10 ms to 1 minute and a voltage drop of more than 10% of the existing value is known as a *Voltage Dip.* There are no standard requirements for the severity or extent of *Voltage Dips* since they are highly dependent on the system configuration. The duration of a *Voltage Dip*is highly dependent on the type of fault concerned and on which relay protection methods are used locally.

Most *Voltage Dips* are caused by earth faults. Whether or not such *Voltage Dips* are transferred to lower voltages depends on which earthing methods are used and on the transformer connections. The *Voltage Dips* may often become deeper and may also spread to other parts of the system if faults occur in more than one phase, but this is relatively rare.

Voltage Flicker

Voltage Flicker is an increase or decrease in voltage over a short period of time, normally associated with a fluctuating load. The characteristics of the particular *Voltage Flicker* problem depend on the characteristics of the load change.

Voltage Flicker may arise during the start-up of an *Induction Generator*, motor, energisation of a transformer or other equipment as the large starting or inrush current may cause the voltage to drop considerably.

TSOs and *Users* are required to minimise the occurrence of *Voltage Flicker* on the *EAPP Interconnected Transmission System* as measured at the *Connection Point*. The *Voltage Flicker* limits are contained in the following *IEC* standards:

(a) *IEC*/TR3 61000-3-7 (1996) "Assessment of emission limits for fluctuating loads in *MV* and HV power systems;"

(b) *IEC* 868/Engineering Recommendation P28 (page 17) "Limits on voltage flicker short term and long term severity values."

In general, the total *Voltage Flicker* at a *Connection Point* shall not exceed:

(i) ± 1% of the steady state voltage level, when these occur repetitively; or

(ii) ± 3% of the steady state voltage level, when these occur infrequently.

6.1.4.3 Harmonics

Harmonics can cause telecommunication interference and thermal heating in transformers; they can disable solid-state equipment and create resonant over-voltages. In order to protect such equipment, harmonics must be managed and mitigated. Harmonics are normally produced by *Plant* and *Apparatus* generating waveforms that distort the fundamental 50 Hz wave.

The following table based on IEEE 519-92 shows the permitted harmonic distortion levels on the *EAPP Interconnected Transmission System.*

Table 6-4: Acceptable Harmonic Distortion

Voltage Level	Acceptable Harmonic Distortion Levels
500 kV, 400 kV, 230 kV, 220 kV	Total Harmonic Distortion of 1.5% with no individual harmonic greater than 1%
132 kV, 110 kV	Total Harmonic Distortion of 2.5% with no individual harmonic greater than 1.5%
66 kV	Total Harmonic Distortion of 5% with no individual harmonic greater than 3.0%

6.1.4.4 Phase Unbalance

Under normal operation, the maximum negative phase sequence component of the phase voltage on the *EAPP Interconnected Transmission System* shall remain below 1%. Under planned *Outage* conditions, infrequent short duration peaks with a maximum value of 2% are permitted for phase unbalance, subject to the prior agreement of the *TSO*.

6.1.5 Technical Standards for Plant and Apparatus

All *Plant* and *Apparatus* connected to or proposed for connection to the *EAPP Interconnected Transmission System* shall meet certain minimum technical standards as detailed below, in the following order of preference:

(a) Relevant current international and African Standards, such as *IEC, ISO, EN*;

(b) Relevant current national standards.

Furthermore, *Plant* and *Apparatus* shall be designed, manufactured and tested in accordance with the quality assurance ISO 9000 family or equivalent.

6.1.6 High Voltage Direct Current

Any *HVDC* interconnection shall be designed so that it has no negative effect on existing equipment connected to the *EAPP Interconnected Transmission System*. Each *HVDC* interconnection must ensure that they do not cause any sub-synchronous resonance, undamped oscillations, rapid voltage variations, harmonic voltages and interference with telecommunications.

The conditions specified in this chapter of the CC apply to *HVDC* interconnections connecting to or within the *EAPP Interconnected Transmission System*. Each *HVDC* Interconnection shall have the following minimum capabilities:

(a) Operate continuously at its declared MW Output at frequencies in the range 49.5 Hz to 50.5 Hz;

(b) Operate and remain connected to the *EAPP Interconnected Transmission System* at frequencies within the range 48.75 Hz to 51.25 Hz;

(c) Remain connected to the *EAPP Interconnected Transmission System* at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds on each occasion that the frequency is below 47.5 Hz;

(d) Remain synchronised to the *EAPP Interconnected Transmission System* during a rate of change of frequency of values up to and including 1 Hz per second;

(e) Remain connected to the *EAPP Interconnected Transmission System* at declared MW Output at voltages within the ranges specified in Section 6.1.4 (Connections -Transmission System Performance Characteristics (Voltage)) for step changes in voltage of up to 10%;

(f) Remain connected during and following *Voltage Dips* at the HV terminals of the *HVDC* Interconnection Transformer of 95% of nominal voltage for a duration of 0.2 seconds and *Voltage Dips* of 50% of nominal voltage for aduration of 0.6 seconds. Following fault clearance, the *HVDC* Interconnection should return to pre-fault conditions subject to normal frequency control and *Automatic Voltage Regulator* responses;

(g) Operate within all normal operating characteristics at a minimum short circuit level at the *Connection Point* of 1000 MVA;

(h) Remain connected to the *EAPP Interconnected Transmission System* during a negative phase sequence load unbalance in accordance with IEC 60034-1;

(i) In an emergency be capable of reversing the power flow on the *HVDC* Interconnection at a rate which shall be no less than the *HVDC* Interconnection registered capacity within five (5) seconds, up to ten (10) times during the life of the plant and no more than two (2) times in any given twelve (12) months;

(j) Active power controllability, control range and ramping rate;

1) With regard to the capability of controlling the transmitted active power:

(a). an HVDC system shall be capable of adjusting the transmitted active power up to its maximum HVDC active power transmission capacity in each direction following an instruction from the System Operator. The System Operator:

(i). may specify a maximum and minimum power step size for adjusting the transmitted active power;

(ii). may specify a minimum HVDC active power transmission capacity for each direction, below which active power transmission capability is not requested; and

(iii). shall specify the maximum response time within which the HVDC system shall be capable of adjusting the transmitted active power upon receipt of request from the System Operator.

(b). the System Operator shall specify how an HVDC system shall be capable of modifying the transmitted active power infeed in case of disturbances into one or more of the AC networks to which it is connected. If the initial delay prior to the start of the change is greater than 10 milliseconds from receiving the triggering signal sent by the System Operator, it shall be reasonably justified by the HVDC system owner to the relevant System Operator.

(c). the System Operator may specify that an HVDC system be capable of fast active power reversal. The power reversal shall be possible from the maximum active power transmission capacity in one direction to the maximum active power transmission capacity in the other direction as fast as technically feasible and reasonably justified by the HVDC system owner to the System Operators if greater than 2 seconds.

(d). for HVDC systems linking various control areas or synchronous areas, the HVDC system shall be equipped with control functions enabling the relevant System Operator s to modify the transmitted active power for the purpose of cross-border balancing.

2) An HVDC system shall be capable of adjusting the ramping rate of active power variations within its technical capabilities in accordance with instructions sent by relevant System Operators. In case of modification of active power according to points (b) and (c) of paragraph 1, there shall be no adjustment of ramping rate.

3) If specified by a relevant TSO, in coordination with adjacent TSOs, the control functions of an HVDC system shall be capable of taking automatic remedial actions including, but not limited to, stopping the ramping and blocking Primary Response and frequency control. The triggering and blocking criteria shall be specified by relevant TSO and subject to notification to the regulatory authority. The modalities of that notification shall be determined in accordance with the applicable national regulatory framework.

(k) Limited frequency-sensitive mode overfrequency (LFSM-O) 'Limited frequency sensitive mode — overfrequency' or 'LFSM-O' means a generating plant, energy storage system or HVDC system operating mode which will result in active power output reduction in response to a change in system frequency above a certain value. The HVDC system shall comply with the following requirements:

1) the HVDC system shall be capable of activating the provision of active power frequency response if the grid exceeds a frequency threshold equal to 50.5 Hz;

2) The active power frequency response shall be linear with a droop setting equal to 5%, droop being the percentage increase in the Frequency that would cause the HVDC system under free governor action to change its output from Full Capacity to zero;

3) the HVDC system shall be capable of activating a power frequency response with an initial delay that is as short as possible, but maximum 2 seconds;

4) upon reaching minimum regulating power level, the HVDC system shall continue operation at this level;

5) the HVDC station shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O active power setpoint will prevail over any other active power setpoints;

6) the HVDC system shall allow adjustment of the frequency threshold between 50.2 Hz and 51.0 Hz inclusive;

7) the HVDC system shall allow adjustment of the droop between 4% and 12% inclusive;

8) the System Operator may instruct the HVDC system operator to adjust the frequency threshold and the droop from time to time;

6.1.7 Protection Criteria

6.1.7.1 General

Protection system design shall be based on simplicity, safety to persons, mitigation, and limitation of equipment damage and control of the spread of any disturbance. The speedy operation of protection systems to clear faults in the *EAPP Interconnected Transmission System* is a pre-requisite to avoid instability and cascade tripping.

The protection systems to be applied to the *User's Plant* and *Apparatus* at the *Connection Point* shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity and selectivity in fault clearing and to minimise the impact of faults on the *EAPP Interconnected Transmission System*.

6.1.7.2 Fault Clearance Times

The clearance times for a fault on the *EAPP Interconnected Transmission System* or for a fault on the *User* system at the *Connection Point* shall not be longer than:

(a) 80 ms for faults at 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.

Nothing shall prevent a *TSO* or *User* utilising faster fault clearance times. Total fault clearance time shall be from fault inception until arc extinction, which therefore includes relay operation, circuit breaker operation and telecommunications signalling times.

6.1.7.3 Circuit Breaker Fail Protection

When a circuit breaker is provided at the *Connection Point* to interrupt fault currents at any side of the *Connection Point*, a circuit breaker fail protection shall also be provided. The circuit breaker fail protection shall be designed to initiate the tripping of all the necessary electrically-adjacent circuit breakers and to interrupt the fault current within the next 250 ms, in the event that the primary protection system fails to interrupt the fault current within the prescribed Fault Clearance Time as detailed in Section 6.1.7 (Connections – Protection Criteria).

6.1.7.4 Reliability of Protection Systems

The reliability of the protection system to initiate the successful tripping of the circuit breakers that are associated with the faulty *Plant* and *Apparatus* shall be not less than 99.5%.

6.1.7.5 Protection of Transmission Facilities

All transmission facilities on the *EAPP Interconnected Transmission System* shall be provided with two fully redundant main protection systems. The two protection systems shall be supplied from separate secondary windings on one Voltage Transformer or potential device and from separate *Current Transformer* secondary windings (using two *Current Transformers*– one *Current Transformer* for each protection system). Separately fused and monitored DC supplies shall be used with the two protection systems. Each main protection shall be capable of operating in stand-alone mode in parallel with the other main protection in a 'one out of two' tripping scheme. To avoid the risk of simultaneous failure of both protection systems due to design deficiencies or equipment problems, the use of two identical protection systems is not appropriate. In addition to the two main protections a separate back-up protection, normally an overcurrent protection, shall be provided.

6.1.7.6 Transmission Circuit Reclosure

Automatic reclosing is appropriate to support continuity of service and to maintain stability of the *EAPP Interconnected Transmission System*. All transmission lines shall be equipped with single pole and three pole tripping as well as high speed automatic reclose facilities. The impact on any generating or transmission facility of such automatic reclosure schemes requires careful consideration so that the reliability of the transmission system is not reduced or compromised.

6.1.8 Technical Requirements for Generating Units

Generating Units equipped with grid-connected synchronous generators shall comply with the requirements of this section.

6.1.8.1 Performance Requirements

It is necessary to define the performance requirements of *Generating Units* which have or could have an impact on the reliability, security and adequacy of supply of the *EAPP Interconnected Transmission System*. In the initial stages of the interconnection only *Generating Units* directly connected to the *EAPP Interconnected Transmission System* and with a registered output of greater than thirty (30) MW shall meet the following requirements:

(a) Each shall be capable of supplying rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the *Generating Unit* terminals. The short circuit ratio of *Generating Units* shall not be less than 0.5;

(b) Each *Generating Unit* must be capable of continuously supplying its registered output within the frequency range given in Section 6.1.4 (Connections – Transmission Performance Characteristics).

(c) The output voltage limits of *Generating Unit*s must not cause voltage variations in excess of ±10% of nominal. Any necessary voltage regulating equipment shall be installed by the *Generation Licensee* to maintain the output voltage level of its *Generating Unit*s;

(d) The *Active Power* output under steady state conditions of any *Generating Unit* directly connected to the *EAPP Interconnected Transmission System* shall not be affected by voltage changes in the normal operating range;

(e) The *Reactive Power* output of a *Generating Unit* under steady state conditions must be fully available within the voltage range of ±10% of nominal voltage at the *Connection Point*.

6.1.8.2 Turbine Control System

The speed governor of each *Generating Unit* must be capable of operating to the standards approved by *EAPP Steering Committee* and the *TSO*. Each *Generating Unit* shall be fitted with a fast acting Turbine Controller to provide power and frequency control under normal operational conditions in accordance with the *Interchange Scheduling and Balancing Chapters*. The turbine speed control principle shall be that the *Generating Unit* output shall vary with rotational speed according to a proportional droop characteristic (*Primary Response*) between 2% and 5%. Superimposed load control loops shall have no negative impact on the steady state and transient performance of the turbine's rotational speed control.

The Turbine Controller shall be sufficiently damped for both isolated and interconnected operation modes. Under all operating conditions, the damping coefficient of the Turbine Speed Control shall be above 3% for gas turbines and 5% for steam turbines.

Under all system operating conditions, the *Generating Unit* speed shall not exceed 103% corresponding to 51.5 Hz for more than 20 seconds in the *EAPP Interconnected Transmission System* (refer to Frequency Sensitive Relays in this chapter.)

The Turbine Speed Controller and any other superimposed control loop such as load control or gas turbine temperature limiting control shall contribute to the *Primary Response* to maintain the unit within the *Generating Unit* capability limits.

The *Primary Response* characteristics shall be maintained under all operational conditions. Additionally, in the event that a *Generating Unit* becomes isolated from the system but is still supplying demand the *Generating Unit* must be able to provide *Primary Response* to maintain the frequency.

6.1.8.3 Automatic Voltage Regulator

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

The *AVR* shall have no negative impact on *Generating Unit* oscillation damping. If required by the *TSO*, in consultation with *EAPP Sub-Committees on Planning and Operation*, a *Power System Stabiliser* (*PSS*) shall be provided. Control principle, parameter setting and switch on/off logic shall be coordinated with the *TSO* and *EAPP Sub-Committees on Planning and Operation* and specified by the *TSO* in the *Connection Agreement*.

6.1.8.4 Frequency Sensitive Relays

The *EAPP Interconnected Transmission System* frequency could rise to 51.5 Hz or fall to 47.5 Hz and *Generating Unit*s must continue to operate within these respective frequency ranges unless *EAPP Sub-Committees on Planning and Operation* or the *TSO* has agreed to any frequency-level relays and/or rate-of-change-of-frequency relays which shall trip such *Generating Unit*s within this frequency range. Such tripping arrangements shall be set out bythe *TSO* in the *Connection Agreement*.

6.1.8.5 Protection Arrangements

Protection of *Generating Unit*s and their connections to the *EAPP Interconnected Transmission System* shall meet the minimum requirements given in Section 6.1.4.

Loss of Excitation

The *Generation Licensee shall* provide the necessary protection device to detect loss of excitation on a *Generating Unit* and initiate a *Generating Unit* trip.

Pole Slipping Protection

Where system requirements dictate, the *TSO* shall specify in the *Connection Agreement* a requirement for *Generation Licensees* to fit pole-slipping protection on their *Generating Unit*s.

6.1.8.6 Black Start Capability

Some *Generating Units* shall be designated to have *Black Start Capability* primarily considering their type and location on the system as set out in Section 10.1.7 (Operations Chapter No. 3 - Emergency Operations). This capability shall enable *Generation Licensees* to restart their facilities without an incoming supply from the *EAPP Interconnected Transmission System*. *EAPP Sub-Committees on Planning and Operations* in consultation with *TSOs* shall nominate *Black Start Generating Units* at a number of strategic locations across the Region. The requirement for a *Black Start Capability* shall be incorporated into the *Connection Agreement* by the relevant *TSO*.

Black Start facilities shall be routinely tested by the *Generation Licensee* to ensure satisfactory operation. The *TSO* shall have the right to require the *Generation Licensee* to demonstrate the *Black Start Capability.*

6.1.9 Technical Requirements for the Interconnected Parties

Protection measures are required to be taken by *EAPP* and *TSOs* to isolate a *National System* or part of such system from the *EAPP Interconnected Transmission System* in case of uncleared faults or the malfunctioning of *Plant* or *Apparatus* which could lead to a System Emergency condition.

Each *TSO* shall make the necessary arrangements to disconnect its *National System* from the *EAPP Interconnected Transmission System* under the circumstances stated below.

6.1.9.1 Area Separation by Frequency Deviation

The cross-border connections to *Neighbouring Systems* shall be tripped when frequency measured at the border falls below 48.75 Hz for more than thirty (30) seconds.

6.1.9.2 Area Separation by Abnormal Transient Conditions

The cross-border connections to *Neighbouring Systems* shall be tripped when an Out of Step pole slipping condition or when sustained inter-area oscillations with amplitudes exceeding an agreed limit are observed.

6.1.9.3 Area Separation by Transmission Line Overloading

The cross-border connections to *Neighbouring Systems* shall be tripped when overloading of the connections occurs. The overload values for the connections shall be agreed between the respective *TSOs* and *EAPP Sub-Committee on Operations.*

6.1.10 Ancillary Services

The CC contains requirements for the minimum capability for certain *Ancillary Services* as set out in further detail in Chapter 16 (ISBC No. 3 -Ancillary Services). These *Ancillary Services* are required in order to maintain the *EAPP Interconnected Transmission System* in a safe, secure and reliable operating state.

In the case of *Generating Units* these *Ancillary Services* include *Primary* and *Secondary Response*, voltage and load flow control and *Black Start Capability*. *TSOs* may enter into *Ancillary Services* Agreements with *Generation Licensees* for the provision of these capabilities. The *Ancillary Services* agreements may also contain commercial arrangements in relation to the provision of these capabilities or of more enhanced capabilities. *Tertiary Reserve* of a *Generating Unit* (fast start hydro and gas turbine *Generating Units* and steam turbine *Generating Units* on hot-standby) is an *Ancillary Service* that is being delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO.*

For transmission facilities the *Ancillary Services* provision is related to voltage control equipment such as shunt capacitors, flow control devices such as Phase Shifting Transformers and to special control systems such as *RAS*. The provision of such *Ancillary Services* would be subject to an agreement between the transmission provider and the *TSO*.

6.1.11 Technical Criteria for Communications Equipment

6.1.11.1 Criteria

The *Control Centre* of each *TSO* shall be equipped with adequate and reliable telecommunication facilities internally and with the *Control Centre*s of other *TSO*s and the *EAPP Coordination Centre* to ensure the exchange of information necessary to maintain the security and reliability of the *EAPP Interconnected Transmission System*. Redundant facilities using alternate routes and different transmission media shall be provided. Each *TSO* is responsible for building, operating and maintaining that part of the telecommunications network located within its *National System* and shall bear all costs associated with the investment, operation, maintenance, and improvement.

Each *TSO* shall take appropriate measures to protect the telecommunications network against risks related to the disruption of operation, data corruption or disclosure of confidential information.

6.1.11.2 Telecommunication System

Dedicated telecommunication channels shall be provided between a *Control Centre* and the *Control Centre* of each *Neighbouring System*. All dedicated telecommunication channels shall not require intermediate switching to establish communication.

Alternate and physically independent telecommunication channels shall be provided for emergency use to back up the circuits used for critical data and voice communications.

Telecommunication Availability

The reliability calculation is based on the *Meant Time Between Failure (MTBF)* and the *Mean Time to Repair (MTTR)*, as *MTBF/(MTBF+MTTR*) of each component between two gateways including the backup links. The target availability is 99.8%.

Restoration services on critical telecommunications channels shall be available twenty-four (24) hours per day, every day of the year. Each *Control Centre* operator should be able to take control of any telecommunication channel for its own use when necessary.

Reliability of Telecommunications Facilities

Vital telecommunications facilities shall be managed tested and actively monitored. Special attention shall be given to back up and emergency telecommunications facilities and equipment not used for routine communications.

Telecommunication Performance

Under normal conditions, the transmission delay, for a given data volume of mutually agreed real-time data exchange, between gateways should not exceed two (2) seconds. The system shall have sufficient bandwidth for a given data volume to meet the required performance. A speed of at least two (2) Mbps is recommended for the interconnected telecommunication channels and a minimum speed of sixty-four (64) kbps is required. A lower speed than two (2) Mbps shall only be used as an interim solution.

Global Positioning System

All *SCADA* systems shall be synchronised to the GPS for accurate time keeping.

Expansions of Telecommunications Services

Expansions and modifications to the telecommunications network and minimum technical standard of components shall be agreed by the *EAPP Steering Committee.*

6.1.11.3 Standards

The following Standards shall be used for telecommunications services:

(a) The *Wide Area Network (WAN)* shall be based on *TCP/IP* protocol;
(b) Communication between *Control Centre*s shall be harmonised and based on ICCP protocol or as agreed between *TSOs* and *EAPP CC;*
(c) Tele-control real-time information shall be based on *IEC* 870-6 TASE.2 protocol;
(d) Non real-time services such as file transfer for exchange of transmission schedules, network model, planning data or statistics shall be based on the *FTP* protocol;
(e) E-mail for special applications shall be based on *SMTP*.

6.1.11.4 Voice Recorder

A recording system shall ensure permanent recording of all telephone conversations between the *TSO Control Centre*s and the *EAPP Coordination Centre* and shall be located in the *Control Centre*s and in the *EAPP Coordination Centre*.

The recording system shall be capable of playing back directly up to one (1) month telephone conversations. Archival storage shall be done on CDs or DVDs or any appropriate medium. Archives shall be stored for at least one (1) year.

6.1.12 Regional System Monitoring

Monitoring equipment shall be provided on the *EAPP Interconnected Transmission System* to enable the *EAPP Coordination Centre* and individual *TSOs* to monitor the *EAPP Interconnected Transmission System* operation and dynamic performance.

Additionally, the *TSO* shall be required to monitor *Governor* selection mode, and *AVR* selection mode for all power generation plants (with total plant capacity above 30 MW) connected to the national grid as indicated in Table 6-5 below.

Table 6-5 below sets out the minimum telemetered data required by *EAPP CC.*

Table 6-5: EAPP CC Minimum Requirements for Telemetering

Type of Connection	Telemetering Required	Telemetered Status Indicators
Interconnected Transmission System Node	MW, Mvar, kV, pf MWh, Mvarh, Amps	All circuit breakers on Interconnected Transmission System
Generating Units connected directly to Interconnected Transmission System	MW, Mvar, kV, pf MWh, Mvarh	Generating Unit main circuit breakers
Generating Unit > 30 MW not directly connected to Interconnected Transmission System	MW, Mvar, kV, pf	Generating Unit main circuit breakers

The *EAPP Coordination Centre* shall define any further system parameters it requires to monitor.

6.1.13 Maintenance Standards

All *TSO's* and *User's Plant* and *Apparatus* connected to or forming part of the *EAPP Interconnected Transmission System* shall be maintained adequately for the purpose for which it is intended and to ensure that it does not pose a threat to the safety of any person or other system facilities. The *EAPP Independent Regulatory Board* through the national Regulatory Body shall have the right to access and inspect the test results and maintenance records relating to such *Plant* and *Apparatus* at any time.

TSOs and *Users* shall ensure that *Plant* and *Apparatus*, including protection systems, are tested and maintained and remain rated for the duty required. *TSOs* shall ensure that a copy of the Annual *Transmission System Capability Statement* including the update of system fault levels is made available.

6.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

6.2.1 Connection Conditions

This section defines acceptable requirements for *Generating Plant* connections. Note that some of the sections below refer to the acronym GCR (*Generating Plant* Connection Requirements) for brevity and later reference.

Compliance with the GCR shall be read in conjunction with the *Generating Plant* characteristics and sizes as specified in Tables 6-6 and Table 6-7 in Section 6.3 of this chapter, which summarise requirements for *Generating Plant* connections.

The organisation(s) responsible for the planning and development of the *KNTS* shall offer to connect and, subject to the signing of the necessary agreements, make available a *Connection Point* to any requesting *Generation Licensee*.

For new units, special consideration shall be given to the impact of the risks on future operating costs, e.g. for *Ancillary Services*. The TNSP shall quantify these expected costs. The special consideration may include obtaining *Authority* approval for including these costs in the *Tariff* base or obligating the *Generation Licensee* to purchase reserves.

6.2.2 Protection

A *Generating Plant,* unit step-up transformer, unit auxiliary transformer, associated busbar ducts and switchgear shall be equipped with well-maintained protection functions, in line with international best practices, to rapidly disconnect appropriate plant sections should a fault occur within the relevant protection zones whose impactmay reflect into the *KNTS*.

The following protection functions shall be provided as defined to protect the *KNTS*.

6.2.2.1 Backup Impedance

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

6.2.2.2 Loss of Field

All *Generating Plants* shall be fitted with a loss of field facility that matches the system requirements. The type of facility to be implemented shall be agreed with the organisation(s) responsible for the planning and development of the *KNTS*.

6.2.2.3 Trip to House Load

This protection shall operate in the event of a complete loss of load. For example, if all the feeder breakers open at a *Generating Plant*, power flow into the system is cut off and the *Generating Plant* will accelerate. At 50.5 Hz the over-frequency facility shall pick up to start the house loading process. At this stage the HV breakers will still be closed. There will be power swings between the units and as soon as a unit has a reverse power condition the protection shall open the generator scnchronising breaker. The units shall island feeding their own auxiliaries. When system conditions have been restored then the islanded units can be resynchronised to the system. This shall be applicable for units which take longer than one (1) hour to be restored back to service following a system outage.

6.2.2.4 Unit Transformer HV Back-up Earth Fault Protection

This is an inverse definite minimum time facility that shall monitor the current in the unit transformer neutral. It can detect faults in the transformer HV side or in the adjacent network. The back-up earth fault facility shall trip the HV circuit-breaker.

6.2.2.5 HV Circuit Breaker Pole Discrepancy Protection

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

6.2.2.6 GeneratorInadvertent Energisation

This protection shall be installed in the HV yard substation or in the generator protection panels. If this protection is installed in the generator protection panels then the DC supply for this protection and that used for the circuit-breaker closing circuit shall be the same. This protection safeguards the *Generating Plant* against an unintended connection to the *KNTS* (back energisation) when at standstill or at low speed.

6.2.2.7 Protection Setting Management and Additional Requirements

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

Required HV breaker tripping, fault clearance times, including breaker operating times depend on system conditions and shall be defined by the organisation(s) responsible for the planning and development of the *KNTS*. Guidelines for primary protection operating times are:

(a) 80 ms where the *Connection Point* is 330kV or above

(b) 80 ms where the *Connection Point* is 220 kV

(c) 100 ms where the *Connection Point* is 132 kV and below

Further downstream breaker tripping (away from the system), fault clearing times, including breaker operating time, shall not exceed the following:

(a) 120 ms plus additional 30 ms for DC offset decay or

(b) 100 ms plus additional 40 ms for DC offset decay.

Where system conditions dictate, these times may be reduced. Where so designed, earth fault clearing times for high resistance earthed systems may exceed the above tripping times.

All protection interfaces with the organisation(s) responsible for the planning and development of the *KNTS* shall be coordinated between the *Users*.

The settings of all the protection tripping functions on the unit protection system of a unit, relevant to *KNTS* performance and as agreed with each *Generation Licensee* in writing, shall be co-ordinated with the transmission protection settings. These settings shall be agreed between the organisation(s) responsible for the planning and development of the *KNTS* and each *Generation Licensee*, and shall be documented and maintained by the *Generation Licensee*, with the reference copy, which reflects the actual plant status at all times, held by the organisation(s) responsible for the planning and development of the *KNTS*. The *Generation Licensee* shall control all other copies.

For system abnormal conditions, a unit is to be disconnected from the *KNTS* in response to conditions at the *Connection Point*, only when the system conditions are outside the plant capability where damage will occur. Protection setting documents shall illustrate plant capabilities and the relevant protection operations.

Any work on the protection circuits interfacing with transmission protection systems (e.g. bus zone) must be communicated to the *SO* before commencing the works. This includes work done during a unit Outage.

6.2.3 Ability of Units to Island

Every unit that does not have *Black Start* capability of less than one hour without power from the *KNTS* shall be capable of unit islanding.

6.2.4 Multiple Unit Tripping (MUT) Risks

A *Generating Plant* 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 time.

6.2.5 Restart after Generating Plant Black-out

6.2.5.1 Thermal Generating Plants other than Gas Turbines

A *Generating Plant* is to be capable of being restarted and synchronised to the *KNTS* following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.

For the purposes of this subsection, examples of unreasonable delay in the restart of a *Generating Plant* are:

(a) Restart of the first unit that takes longer than 4 hours after restart initiation

(b) Restart of the second unit that takes longer than 2 hours after the synchronising of the first unit.

(c) Restarting of all other units that take longer than 1 hour 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 *Generation Licensee*

(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.

6.2.5.2 Geothermal Generating Plants

A *Generating Plant* is to be capable of being restarted and synchronised to the *KNTS* following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.

For the purposes of this subsection, examples of unreasonable delay in the restart of a *Generating Plant* are:

(a) Restart of the first unit that takes longer than 6 hours after restart initiation

(b) Restart of the second unit that takes longer than 4 hours after the synchronising of the first unit.

(c) Restarting of all other units that take longer than 4 hour 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 *Generation Licensee*

(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.

6.2.5.3 Hydro and Gas Turbines

A *Generating Plant* is to be capable of being restarted and synchronised to the *KNTS* following restoration of external auxiliary AC supply without unreasonable delay resulting directly from the loss of external auxiliary AC supply.

For the purposes of this subsection, examples of unreasonable delay in the restart of a *Generating Plant* are:

(a) Restart of the first unit that takes longer than 30 minutes after restart initiation

(b) Restarting of all other units 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 *Generation Licensee* and

(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.

6.2.6 On-load Tap Changing for Generating Plant Step-up Transformers

All *Generating Plant* step-up transformers shall have on-load tap changing with remote control capability. The range and mode of control shall be agreed between the organisation(s) responsible for the planning, development, and operation of the *KNTS* and the *Generation Licensee*.

6.2.7 Emergency Unit Capabilities

All *Generation Licensee*s shall specify their units' capabilities for providing emergency support under abnormal power system conditions, as described in Chapter 10 (Operation Chapter No. 3 -Emergency Operation).

6.2.8 Facility for Independent Generating Plant Action

Frequency control under system island conditions shall revert to the *Generating Plant*s as the last resort, and units and associated plant shall be equipped to handle such situations. The required control range is from 49 to 51 Hz.

6.2.9 Automatic Under-Frequency Starting

It may be agreed with the *SO* that a *Generating Plant* that is capable of automatically starting within 10 minutes shall have automatic under-frequency starting. This starting shall be initiated by frequency-level facilities with settings in the range 49Hz to 50Hz as specified by the *SO.*

6.2.10 Testing and Compliance Monitoring

(a) A *Generation Licensee* shall keep records relating to the compliance by each of its units with each section of this chapter 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).

(b) Within one (1) month after the end of June and December, a *Generation Licensee shall* review, and confirm to the *SO*, compliance by each of that *Generation Licensee's* units with every *GCR* during the past six (6) month period.

(c) A Generation Licensee shall conduct tests or studies to demonstrate each unit at the Generating Plant as well as the entire Generating Plant complies with each of the requirements of this code. Tests shall be carried out on new units, after every Outage where the integrity of any GCR may have been compromised, to demonstrate the compliance of the unit with the relevant GCR(s). The Generation Licensee shall continuously monitor its compliance with all the connection conditions of the KNTGC.

 The System Operator may at any time issue instructions requiring tests to be carried out on any Generating Plant connected to the Transmission System. All tests shall be of sufficient duration and shall be conducted no more than twice a year except when there are reasonable grounds to justify further tests.

(d) Each Generation *Licensee shall* submit to the *SO* a detailed test procedure, emphasising system impact, for each relevant part of this chapter prior to every test.

(e) If a *Generation Licensee* determines, from tests or otherwise, that one of its *Generating Plant*s is not complying with one or more sections of this chapter, then the *Generation Licensee* shall:

 (i) Promptly notify the *SO*of that fact;

 (ii) Promptly advise the *SO* of the remedial steps it proposes to take to ensure that the relevant *Generating Plant* (as applicable) can comply with this chapter and the proposed timetable for implementing those steps;

 (iii) Diligently take such remedial action as will ensure that the relevant *Generating Plant* (as applicable) can comply with this chapter. The *Generation Licensee* shall regularly report in writing to the *SO* on its progress in implementing the remedial action;

 (iv) After taking remedial action as described above, demonstrate to the reasonable satisfaction of the *SO* that the relevant *Generating Plant* (as applicable) is then complying with this chapter.

6.2.11 Non-compliance Suspected by the SO

(a) If at any time the *SO* believes that a *Generating Plant* is not complying with this chapter, the *SO* must notify the relevant *Generation Licensee* of such non-compliance specifying the chapter section concerned and the basis for the *SO*'s belief.

(b) If the relevant *Generation Licensee* believes that the *Generating Plant* is complying with the chapter, then the *SO* and the *Generation Licensee* must promptly meet to resolve their difference.

(c) Any dispute shall be refererred in accordance to chapter 3 of the KNTGC.

6.2.12 Unit Modification

6.2.12.1 Modification Proposals

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

- (i) Contain detailed plans of the proposed change or modification;
- (ii) State when the *Generation Licensee* intends to make the proposed change or modification; and
- (iii) Set out the proposed tests to confirm that the relevant unit as changed or modified operates in the manner contemplated in the proposal, can comply with this chapter.

(b) If the TNSP disagrees with the proposal submitted, it may notify the relevant *Generation Licensee*, and the TNSP and the relevant *Generation Licensee* shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement.

(c) Where the modification results to a change of license conditions, then generation licensee shall apply for an amendment/new license to the Authority.

6.2.12.2 Implementing Modifications

(a) The *Generation Licensee* 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 TNSP and Authority (where applicable).

(b) The *Generation Licensee* shall notify the *TNSP* promptly after an approved change or modification to a unit has been implemented.

6.2.12.3 Testing of Modifications

(a) The *Generation Licensee* shall confirm that a change or modification to any of its units 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.

(b) Within twenty (20) business days after any such test has been conducted, the relevant *Generation Licensee* shall provide the *SO* with a report in relation to that test (including test results of that test, where appropriate).

6.2.13 Equipment Requirements

Where the *Generation Licensee* needs to install equipment that connects directly with equipment of the organisation(s) responsible for the planning and development of the *KNTS*, for example in the high voltage yard of the organisation(s) responsible for the planning and development of the *KNTS*, such equipment shall adhere to the design requirements of the organisation(s) responsible for the planning and development of the *KNTS* as set out in this chapter.

6.3 GENERATING PLANT CONNECTION REQUIREMENTS

Table 6-6: Summary of the Requirements Applicable to Specific Classes of Units Other than Hydro

<table>
<tr><th colspan="2" rowspan="2">Grid Code Requirement</th><th colspan="6">Units other than Hydro (MVA rating)</th></tr>
<tr><th><20</th><th>20 to 100</th><th>100 to 200</th><th>200 to 300</th><th>300 - 800</th><th>>800</th></tr>
<tr><td>GCR1</td><td>Plant availability</td><td>-</td><td>Depends on System Requirements</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>GCR2</td><td>Plant reliability</td><td>-</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td rowspan="12">GCR3</td><td>Protection</td><td></td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>- Backup Impedance</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Loss of Field</td><td>-</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Pole Slipping</td><td>-</td><td>Depends on Sys Reqts</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Trip to House Load</td><td>-</td><td>-</td><td>Depends on Sys Reqts</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Gen TRFR backup earth fault</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- HV Breaker Fail</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- HV Breaker Pole Disagreement</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Unit Switch-onto-standstill Protection</td><td>-</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Main Protection only</td><td>Yes</td><td>Yes</td><td rowspan="2">Depends on Sys Reqts</td><td>-</td><td>-</td><td>-</td></tr>
<tr><td>- Main Protection (monitored) or main and backup</td><td>-</td><td>-</td><td rowspan="2">Depends on Sys Reqts</td><td>-</td><td>-</td></tr>
<tr><td>- Main and Backup Protection (both monitored)</td><td>-</td><td>-</td><td>-</td><td>Depends on Sys Reqts</td><td>Yes</td></tr>
<tr><td>GCR4</td><td>Ability To Island</td><td>-</td><td>-</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td rowspan="2">GCR5</td><td>Excitation system requirements</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>- Power System Stabiliser</td><td>-</td><td>-</td><td>Depends on Sys Reqts</td><td>Depends on Sys Reqts</td><td>Yes</td><td>Yes</td></tr>
</table>

Grid Code Requirement		*Unit*s other than Hydro (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
	- Limiters	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR7	Multiple Unit tripping	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 unit at station
GCR8	Governing	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR11	External Supply Disturbance Withstand Capacity	Depends on Sys Reqts	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GCR13	*Emergency unit* capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on Sys Reqts	Yes	Yes	Yes
GCR15	Visibility to the SO's SCADA system before hot commissioning and during operations	Yes	Yes	Yes	Yes	Yes	Yes

Table 6-7: Summary of the Requirements Applicable to Specific Classes of Hydro Units

Grid Code Requirement		Hydro Units (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR1	Plant availability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR2	Plant reliability	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR3	**Protection**						
	- Backup Impedance	Yes	Yes	Yes	Yes	Yes	Yes

Grid Code Requirement		Hydro Units (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
	- Loss of Field		Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Pole Slipping	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes
	- Trip to House Load	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Gen *TRFR* backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Fail	Yes	Yes	Yes	Yes	Yes	Yes
	- *HV* Breaker Pole Disagreement	Yes	Yes	Yes	Yes	Yes	Yes
	- *Unit* Switch-onto-standstill *Protection*	-	Depends on Sys Reqts	Yes	Yes	Yes	Yes
	- Main *Protection* only	Yes	Yes	Depends on Sys Reqts	-	-	-
	- Main *Protection* (monitored) or main and backup	-	-		Depends on Sys Reqts	-	-
	- Main and Backup *Protection* (both monitored)	-	-	-		Depends on Sys Reqts	Yes
GCR4	Ability To Island	-	-	-	-	-	-
GCR5	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power System Stabiliser	-	-	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes
	- Limiters	-	Depends on Sys Reqts	- Yes	Yes	Yes	Yes
GCR6	Reactive Capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR7	Multiple Unit tripping	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 unit at station
GCR8	Governing	Depends on Sys Reqts	Yes	Yes	Yes	Yes	Yes
GCR9	Restart after Station Blackout	-	Depends on Sys Reqts	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	Black Starting	-	If agreed	If agreed	If agreed	GCR10	Black Starting
GCR11	External Supply Disturbance Withstand Capacity	Depends on Sys Reqts	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station

Grid Code Requirement		Hydro Units (*MVA* rating)					
		<20	20 to 100	100 to 200	200 to 300	300 - 800	>800
GCR12	On load tap Changer for generating *Unit* step up transformers	Depends on Sys Reqts	Yes	Yes	Yes	GCR12	On load tap Changer for generating *Unit* step up transformers
GCR13	*Emergency unit* capabilities	Depends on Sys Reqts	Depends on Sys Reqts	Yes	Yes	Yes	Yes
GCR14	Independent action for control in system island	-	-	Depends on Sys Reqts	Yes	Yes	Yes
GCR15	Visibility to the SO's SCADA system before hot commissioning and during operations	Yes	Yes	Yes	Yes	Yes	Yes

7 CONNECTIONS – VARIABLE RENEWABLE POWER PLANTS

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

7.1 EAPP IC REQUIREMENTS

7.1.1 Introduction

EAPP IC requirements for *RPP* primarily address wind and solar resources.

7.1.2 Technical Requirements for Wind and Solar Generating Plants

The requirements for *Generating Plants* set out in Section 6.1.8 in Chapter 6 (Connections) refer to synchronous units. *Wind Turbine Generating Plants* and *Solar Power Generating Plants* do not have the same characteristics as synchronous *Generating Plants* and alternative provisions are required. This section sets out the specific requirements for controllable *Wind Turbine Generating Plants* and *Solar Power Generating Plants*.

7.1.2.1 Fault Ride-through Requirements

A controllable *Wind Turbine*/*Solar Power Generating Plant* shall remain connected to the *EAPP* Interconnected Transmission System for *Voltage Dips* on any or all phases, where the system phase voltage measured at the *HV* terminals of the connection transformer remains above a level to be defined by the *TSO* and specified in the *Connection Agreement*.

In addition to remaining connected to the *EAPP* Interconnected Transmission System, the controllable *Wind Turbine/Solar Power Generating Plant* shall have the technical capability to provide the following functions:

(a) During a *Voltage Dip* the controllable *Wind Turbine/Solar Power Generating Plant* shall provide *Active Power* in proportion to retained voltage and maximise reactive current to the *EAPP* Interconnected Transmission System without exceeding its declared limits. The maximisation of reactive current shall continue for at least 600 ms or until the voltage recovers to within the normal operational range of the *EAPP* Interconnected Transmission System whichever is the sooner;

(b) The controllable *Wind Turbine/Solar Power Generating Plant* shall provide at least 90% of its maximum available *Active Power* as quickly as possible and in any event within one (1) second of the voltage recovering to the normal operating range.

7.1.3 Power System Frequency Ranges

As displayed in Figure 7-1, the controllable *Wind Turbine/Solar Power Generating Plant* shall have the capability to:

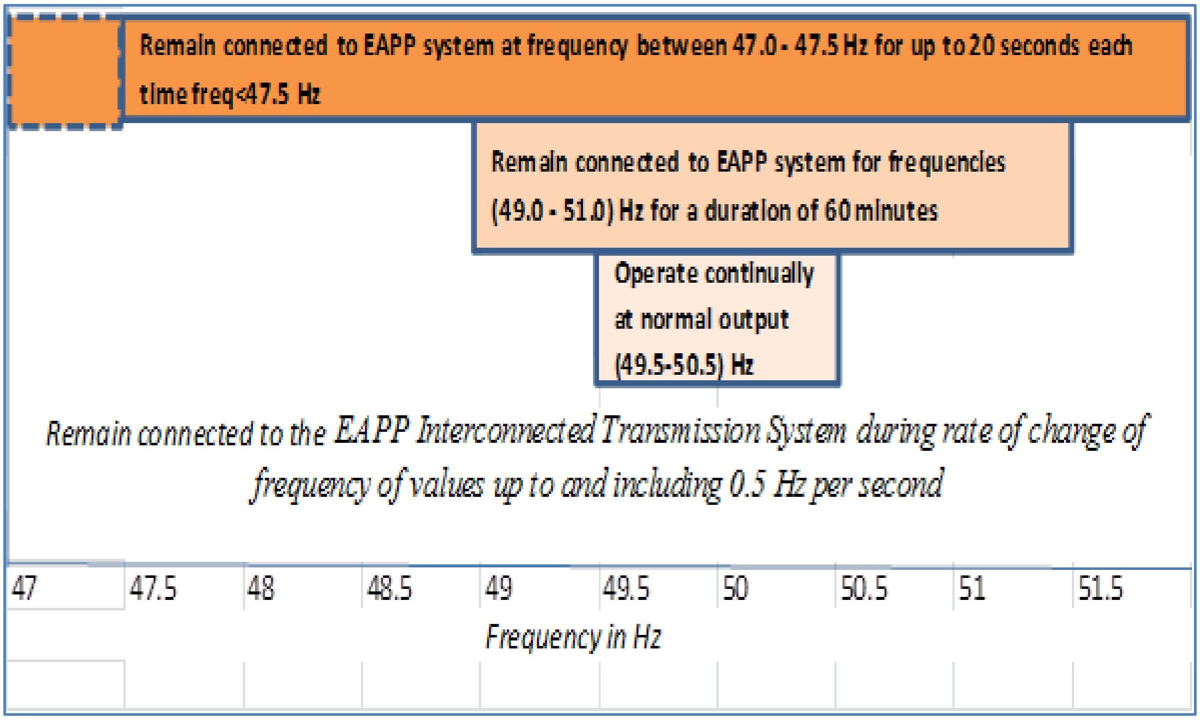
(a) Operate continuously at normal rated output at frequencies in the range 49.5 Hz to 50.5 Hz;

(b) Remain connected to the *EAPP* Interconnected Transmission System at frequencies within the range 49.0 Hz to 51.0 Hz for a duration of 60 minutes;

(c) Remain connected to the *EAPP* Interconnected Transmission System at frequencies within the range 47.0 Hz to 47.5 Hz for a duration of 20 seconds each time that the frequency is below 47.5 Hz, and

(d) Remain connected to the *EAPP* Interconnected Transmission System during rate of change of frequency of values up to and including 0.5 Hz per second.

Figure7-1: Frequency Ranges for Remaining Connected



7.1.3.1 Active Power Control

The *Wind Turbine/Solar Power Generating Plant* control system shall be capable of operating the *Generating Plant* at a reduced level if the *Active Power* output has been restricted by the *TSO*. The *Wind Turbine/Solar Power Generating Plant* control system shall be capable of receiving an on-line *Active Power* Control *Set-point* sent by the *TSO* and shall commence implementation of the *Set-point* within 10 seconds of receipt of the signal from the *TSO*. The rate of change of output to achieve the *Active Power* Control *Set-point* should be no less than the maximum ramp rate settings of the *Wind Turbine/Solar Power Generating Plant* control system, as advised by the *TSO*.

7.1.3.2 Frequency Response

The frequency response system of *Wind Turbine/Solar Power Generating Plants* shall have the capabilities set out in the power frequency response curve agreed with the *TSO*.

7.1.3.3 Ramp Rates

The *Wind Turbine/Solar Power Generating Plant* control system shall be capable of controlling the ramp rate of its *Active Power* output with a maximum *MW* per minute ramp rate set by the *TSO*. There shall be two maximum ramp rate settings. The first ramp rate setting shall apply to the *MW* per minute ramp rate averaged over one (1) minute. The second ramp rate setting shall apply to the *MW* per minute ramp rate averaged over ten (10) minutes. These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down.

The power output of *Solar Power Generating Plants* has to be reduced in steps of 10% per minute, under any operating condition and from any working point to a maximum power value (target value) which could correspond also to 100% power reduction, without disconnection of the *Generating Plant* from the network.

It is recognised that falling wind speed or frequency response may cause either of the maximum ramp rate settings to be exceeded.

It shall be possible to vary each of these two maximum ramp rate settings independently over a range between one (1) and thirty (30) *MW* per minute. The *Wind Turbine Generating Plant* control system shall have the capability to set the ramp rate in *MW* per minute averaged over both one (1) and ten (10) minutes.

The *Wind Turbine/Solar Power Generating Plant* operator and the *TSO* shall agree a procedure for setting and changing the ramp rate control.

7.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

This section addresses *KNTGC* requirements for Variable *Renewable Power Plants* including wind and solar. The Connections - Variable *Renewable Power Plant* (V*RPP*) Chapter has been developed to address particular issues with variable wind and solar power plants.

The V*RPP* Chapter sets out the requirements for variable V*RPPs* so that they will be able to contribute to the stability of the *Kenya National Transmission System*.

7.2.1 Objective

The primary objective of this V*RPP* Chapter is to specify minimum grid connection technical and design requirements for variable V*RPPs* connected to or seeking connection to the *Kenya National Transmission System.*

7.2.2 Scope

The requirements in the V*RPP* Chapter shall apply to all V*RPPs* with a design capacity of 10 *MVA* or larger connected or seeking connection to the *Kenya National Transmission System*, the *SO*, and prospective electrical *Transmission Network Service Providers.*

This V*RPP* Chapter shall, at minimum, apply to the following V*RPP* technologies:

(a) Wind

(b) Solar Photovoltaic

7.2.3 Technical Requirements

7.2.3.1 Fault Ride-through Requirements for VRPPs

Fault ride-through refers to the ability of a *Generating Plant* to remain connected during a system voltage disturbance.

The *EAPP IC* requirements specified under Section 7.1.2 shall apply to all V*RPPs* in the *KNTS.*

Four main characteristics typically provide the requirements for *RPP*s in the event of a voltage disturbance:

(a) Conditions for which the V*RPP Generating Plant* must remain connected
(b) *Active Power* provision during fault
(c) Voltage support requirements during the disturbance
(d) Restoration of *Active Power* after the fault has been cleared

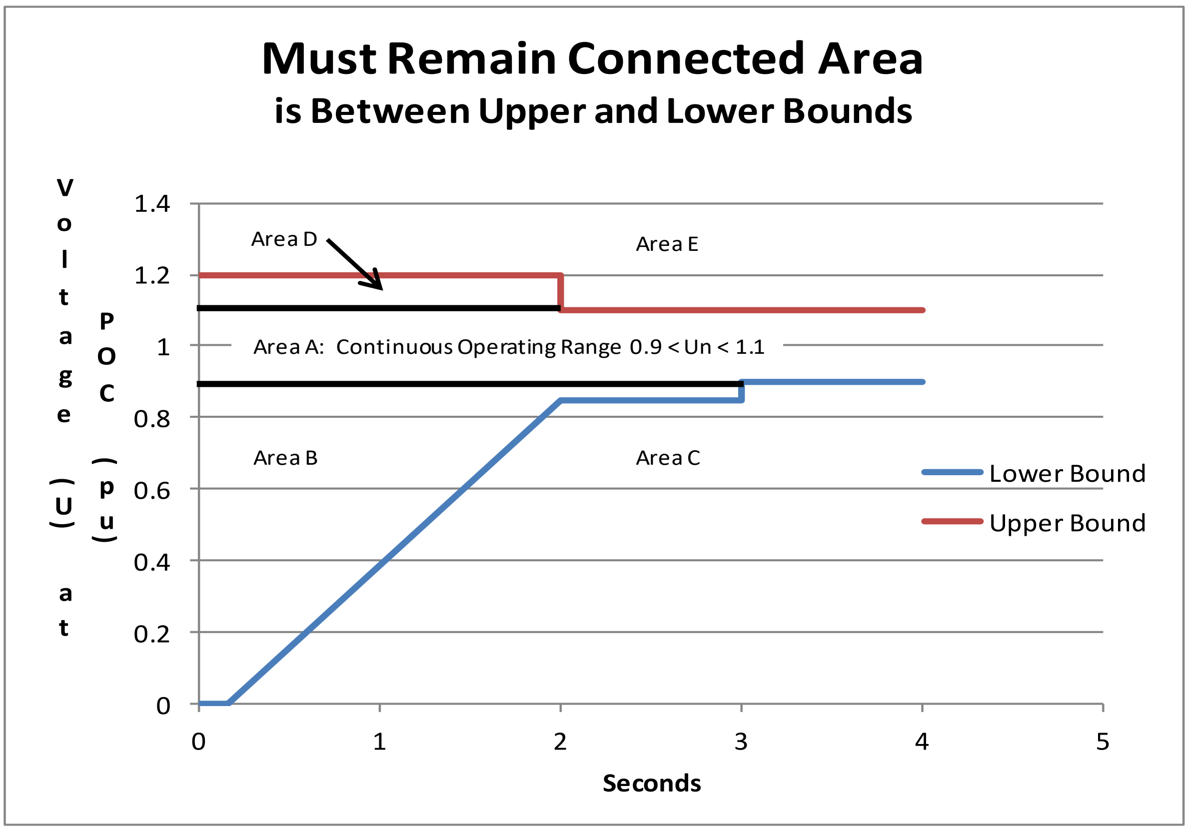
Each is discussed in more detail below.

An VRPP shall remain connected to the *Kenya National Transmission System* for voltage disturbances on any or all phases, where the system phase voltage measured at the HV terminals of the connection transformer remains above a specified level for a specified length of time.

The "remain connected" requirements during fault take the form of a voltage vs. time profile which dictates the level of voltage drop or increase that V*RPPs must* be capable of withstanding along with the time for which the voltage drop or increase should be endured.

Figure 7-2 shows the combinations of voltages and time that the *RPP* shall be able to endure.

Figure7-2: Voltage Must Remain Connected Area



(i) Area A shows that the V*RPP* shall be able to operate continuously between 0.9 p.u. and 1.1 p.u after any single *Contingency.* In Area A the *RPP* shall stay connected to the network and uphold normal production.

(ii) Area B is the area between the Lower Bound and the bottom of the continuous operating range, at 0.9 p.u. In Area B the RPP shall stay connected to the network. Figure 7-2 shows that the RPP shall be able to withstand voltage drops to zero, measured at the Connection Point, for a minimum period of 0.15 seconds without disconnecting. Less severe voltage drops increase the length of time that must be endured. Just below 0.85 p.u. the voltage drop shall be endured for nearly two seconds. At 0.85 p.u. the voltage drop shall be endured a minimum of three seconds.

(iii) Area D is the area between the Upper Bound and the top of the continuous operating range, at 1.1 p.u. In Area D the VRPP shall stay connected to the network. Figure 7-2 shows that the RPP shall be able to withstand voltage increases to 1.2 p.u. for at least two seconds.

(iv) Area C is the area outside the Lower Bound and below the continuous operating range, at 0.9 p.u. In Area C, disconnecting the VRPP is allowed.

(v) Area E is the area above the Upper Bound and above the continuous operating range, at 1.1 p.u. In Area E disconnecting the VRPP is allowed.

7.2.3.2 Active Power Provision during Fault

During a *Voltage Dip* the controllable V*RPP shall* provide *Active Power* in proportion to retained voltage and maximise reactive current to the *Kenya National Transmission System* without exceeding its declared limits.

7.2.3.3 Reactive Current Flows during Fault

The maximisation of reactive current during a fault shall continue for at least 600 ms or until the voltage recovers to within the normal operational range of the *Kenya National Transmission System*, whichever is the sooner.

7.2.3.4 Active Power Recovery after Fault

The controllable *RPP shall* provide at least 90% of its maximum available *Active Power* as quickly as possible and in any event within one second of the voltage recovering to the normal operating range.

7.2.3.5 Power System Remain Connected Frequency Ranges

Frequency is the one parameter common to all members of a synchronous electric power system, and an accepted indicator of that system's ability to balance resources and demand as well as to manage disturbances. This requires that V*RPPs* remain connected beyond the frequency range associated with normal operation.

(a) Under normal operation, the frequency of the *Kenya National Transmission System* shall be nominally 50 Hz, shall be controlled between 49.50 Hz and 50.50 Hz (±1%), and shall be capable of continuous operation.

(b) Increasingly severe system disturbances require progressively wider frequency bands and reduce the time required to operate within the specified frequency range:

   (i) For a frequency band of 49.00–51.00 Hz (±2%) an *RPP* shall be capable of operating for at least 60 minutes.

   (ii) For a frequency band of 48.00–51.50 Hz (-4% to + 3%) an *RPP* shall be capable of operating for at least 30 minutes.

   (iii) For a frequency band of 47.50–51.50 Hz (-5% to +3%) an *RPP* shall be capable of operating for at least 3 minutes.

   (iv) Under extreme system operation or fault conditions, an *RPP* shall be capable of operating at frequencies above 51.50 Hz for at least 20 seconds.

   (v) For frequencies below 47.00 Hz, an RPP shall be capable of operating for at least 200 ms.

(vi) For frequencies above 52.00 Hz, an *RPP* must disconnect as indicated in Table 7-1.

(c) VRPPs shall remain connected during rate of change of frequency of values up to and including 1.0 Hz per second.

Table7-1: Frequency Limits in the Kenya National Transmission System

Frequency Limits	Duration
49.50 Hz to 50.50 Hz	Continuous operation (normal)
49.00 Hz to 51.00 Hz	For duration of at least 60 minutes
48.00 Hz to 51.50 Hz	For duration of at least 30 minutes
47.50 Hz to 51.50 Hz	For duration of at least 3 minutes
<47.50 Hz or >51.50 Hz	For duration of at least 20 seconds
<47.00 Hz for more than 0.2 sec	May disconnect
>52.00 for more than 4 sec	Must disconnect

7.2.3.6 Active Power Control

Active Power Control requirements shall be consistent with the *EAPP IC* requirements in Section 7.1.2.

The *RPP* control system shall be capable of operating the *RPP* at a reduced level if the *Active Power* output has been restricted by the *SO*. The *RPP* control system shall be capable of receiving an on-line *Active Power Control Set-point* sent by the *SO* and shall commence implementation of the set-point within 10 seconds of receipt of the signal from the *SO*. The rate of change of output to achieve the *Active Power Control Set-point* should be no less than the maximum ramp rate settings of the *RPP* control system, as advised by the *SO.*

7.2.3.7 Safety Standards

Safety equipment for wind and solar *Generating Plants* shall include:

(a) Manual disconnect switches;
(b) Earthing systems; and
(c) Shutoff devices.

IEC 61400-24:2010 shall be followed for earthing of wind turbine generators. IEC 61730 shall be followed for PV systems.

7.2.4 Frequency Response

Frequency response can be achieved through decreasing VRPP power output when frequency exceeds the upper bound of a specified acceptable frequency range, and by increasing Generating Plant power output when frequency falls below the lower bound of the specified range. Thus a VRPP must operate at a level below its instantaneous available capacity, if it is to provide both upward and downward frequency regulation capability. The frequency response system of VRPPs shall have the capabilities set out in the power frequency response curve agreed with the System Operator. It is usually economically beneficial for VRPPs to operate at their instantaneous available capacity. If they operate below their instantaneous available capacity, wind, photovoltaic, and run-of-river hydro Plants lose some of the energy they could have captured. The same is true for other types of RPP which may lack energy storage facilities. This may be a factor in reaching agreement with the System Operator on the power frequency curve. However, VRPPs shall operate below their instantaneous available capacity when instructed to do so by the System Operator.

7.2.4.1 Limited frequency-sentitive mode overfrequency (LFSM-O)

Limited frequency sensitive mode — overfrequency or LFSM-O means a generating plant, energy storage system or HVDC system operating mode which will result in active power output reduction in response to a change in system frequency above a certain value. The Generating Plant shall comply with the following requirements:

a) the Generating Plant shall be capable of activating the provision of active power frequency response if the grid exceeds a frequency threshold equal to 50.5 Hz;
b) The active power frequency response shall be linear with a droop setting equal to 5%, droop being the percentage increase in the Frequency that would cause the VRPP to change its output from actual available Capacity to zero;
c) the Generating Plant shall be capable of activating a power frequency response with an initial delay that is as short as possible, but maximum 2 seconds;
d) upon reaching minimum regulating power level, the Generating Plant shall continue operation at this level;
e) the Generating Plant, energy system or HVDC station shall be capable of operating stably during LFSM-O operation. When LFSM-O is active, the LFSM-O setpoint will prevail over any other active power setpoints;
f) the Generating plant shall allow adjustment of the frequency threshold between 50,2 Hz and 51.0 Hz inclusive;
g) the Generating plant shall allow adjustment of the droop between 4% and 12% inclusive;
h) the System Operator may instruct the Generating plant operator to adjust the frequency threshold and the droop from time to time.

7.2.5 Ramp Rates

Ramp Rate requirements shall be consistent with the *EAPP IC* requirements in Section 7.1.2.

The V*RPP* control system shall be capable of controlling the ramp rate of its *Active Power* output with a maximum MW per minute ramp rate set by the *SO.* There shall be two maximum ramp rate settings. The first ramp rate setting shall apply to the MW ramp rate averaged over one (1) minute. The second ramp rate setting shall apply to the MW per minute ramp rate averaged over ten (10) minutes. These ramp rate settings shall be applicable for all ranges of operation including start up, normal operation and shut down. It is recognised that falling wind speed, rapidly changing cloud conditions, or frequency response may cause either of the maximum ramp rate settings to be exceeded.

It shall be possible to vary each of these two maximum ramp rate settings independently over a range between one (1) and thirty (30) MW per minute. The *RPP* control system shall have the capability to set the ramp rate in MW per minute averaged over both one (1) and ten (10) minutes.

The V*RPP* operator and the *SO shall* agree a procedure for setting and changing the ramp rate control.

7.2.6 Reactive Power Capability

The *Reactive Power* capability of a V*RPP* shall be available within the parameters presented in Table 7-2.

Table7-2: *Reactive Power* Capability

Voltage, pu Power, p.u. of P_{rated}	Active power (MW) output p.u. of nameplate MW rating P_{rated}	Reactive power (Mvar) in p.u. of nameplate MW rating P_{rated}
0.90 to 1.10	20-100% P_{rated}	-0.35 P_{rated} to +0.35 P_{rated}
0.90 to 1.10	0-20% P_{rated}	-0.2 P_{rated} to +0.2 P_{rated}

If the grid voltage at the point of connection is higher than 1.05 pu, the required range for injection of reactive power shall be reduced linearly with increasing voltage in pu, such that at 1.10 pu the maximum required possible injection shall be zero. If the grid voltage at the point of connection is lower than 0.95 pu, the required range for absorption of reactive power shall be reduced linearly with increasing voltage in pu, such that at 0.90 pu the maximum required possible absorption shall be zero.

Reactive power control

7.2.6.1 **Requirements** for reactive power and voltage control

The Generating Plant shall be capable of providing reactive power automatically by either voltage control mode, reactive power control mode or power factor control mode as follows:

a) For the purposes of voltage control mode:
   (i).the Generating Plant shall be capable of contributing to voltage control at the connection point by provision of reactive power exchange with the network with a setpoint voltage covering 0,95 to 1,05 pu in steps no greater than 0,01 pu, with a slope (i.e., the ratio of the change in voltage, based on reference 1 pu voltage, to a change in reactive power in-feed from zero to maximum reactive power, based on maximum reactive power) having a range of at least 2 to 7 % in steps no greater than 0,5 %. The reactive power output shall be zero when the grid voltage value at the connection point equals the voltage setpoint;
   (ii).the setpoint may be operated with or without a dead band selectable in a range from zero to ± 5 % of reference 1 pu network voltage in steps no greater than 0,5 %;
   (iii).following a step change in voltage, the Generating Plant shall be capable of achieving 90 % of the change in reactive power output within a time t1 to be specified by the system operator in the range of 1 to 5 seconds and must settle at the value specified by the slope within a time t2 to be specified by the system operator in the range of 5 to 60 seconds, with a steady-state reactive tolerance no greater than 5 % of the maximum reactive power;
   (iv).The time t1 shall initially be set at 1 second, t2 at 5 seconds. The System Operator or the DNSP may instruct the generator plant operator to adjust the voltage setpoint, as well as t1 and t2 from time to time;
   (v).The requirements of voltage control mode only apply to generating plants satisfying one or both of the following conditions:

- rated nameplate power 10 MW or higher
- rated voltage of Connection Point 33 kV or above

(vi). For the purpose of reactive power control mode, the Generating Plant shall be capable of setting the reactive power setpoint anywhere in the reactive power range specified above, with setting steps no greater than 5 MVAr or 5 % (whichever is smaller) of full reactive power, controlling the reactive power at the connection point to an accuracy within +/- 5 MVAr or +/- 5 % (whichever is smaller) of the full reactive power;

(vii). For the purpose of power factor control mode, the VRPP shall be capable of controlling the power factor at the connection point within the required reactive power range, specified above, with a target power factor in steps no greater than 0.01. The System Operator or the TNSP shall specify the target power factor value, its tolerance and the period of time to achieve the target power factor following a sudden change of active power output. The tolerance of the target power factor shall be expressed through the tolerance of its corresponding reactive power. This reactive power tolerance shall be expressed by either an absolute value or by a percentage of the maximum reactive power of the power park module;

The System Operator shall specify which of the above three reactive power control modes and associated setpoints is to apply, and what further equipment is needed to make the adjustment of the relevant setpoint operable remotely.

7.2.7 Rate of Change of Frequency Range

The requirements of Chapter 5 (Planning) for remaining connected during a frequency disturbance apply when the rate of change of frequency is within certain limits. Outside these limits, the unit is not obliged to remain connected. VRPPs shall remain connected to the *Kenya National Transmission System* during rate of change of frequency of values up to and including 1.0 Hz per second.

7.2.8 Voltage and Frequency for Synchronisation

VRPPs shall only be allowed to connect to the *Kenya National Transmission System*, at the earliest, 3 seconds after the voltage at the *Connection Point* is within ±5% around the nominal voltage, and the frequency in the *Kenya National Transmission System* is within the range of 49.0 Hz and 50.2 Hz, or otherwise as agreed with the *SO.*

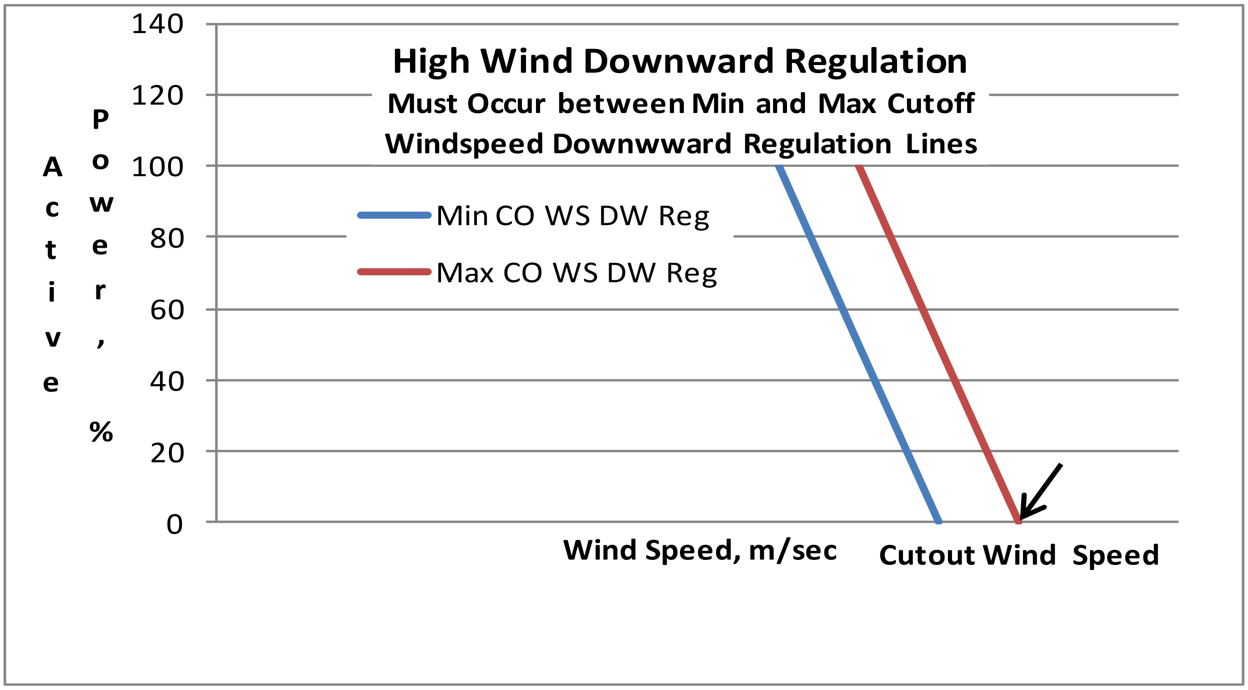
7.2.9 Active Power Control for Wind Generating Plants

The *Wind Turbine Generating Plant* shall stay connected to the *Kenya National Transmission System* at average wind speeds below a predefined cut-out wind speed. The cut-out wind speed shall as a minimum be 25m/s, based on the wind speed measured as an average value over a 10-minute period. To prevent instability in the *Kenya National Transmission System*, the wind power *Plant* shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the *Active Power* production at wind speeds close to the cut-out windspeed.

It shall be possible to continuously downward regulate the *Active Power* supplied by the V*RPP* to an arbitrary value in the interval from 100% to at least 40% of the rated power. When downward regulation is performed, the shutting-down of individual *Wind Turbine Generating Plant* units is allowed so that the load characteristic is followed as well as possible.

Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the area between the slanted lines shown in Figure 7-3 Illustrative High Wind Downward Regulation Chart. When downward regulation is being performed, the shutting down of individual *Wind Turbine Generating Plant* units is allowed. The downward regulation band shall be agreed with the *SO* upon Commissioning of the *Wind Turbine Generating Plant*.

Figure7-3: Illustrative High Wind Downward Regulation Chart



7.2.10 System Reserve Requirements

Increasing penetration of wind and photovoltaic generation, and to a limited extent other V*RPPs*, can increase the need for various kinds of reserves. The variability of their output requires higher levels of both planning and operating reserves to offset the greater chance of being or going off-line when needed. They also contribute little or no inertia to the system, increasing the need for frequency regulation, which may lead to a need for higher levels of *Regulating* and *Spinning Reserve*. These factors shall be taken into account in establishing both planning and operating reserve requirements.

7.2.11 Renewable Power Plant Hourly MW Production Forecast

Each V*RPP* shall have the capability to produce and submit to the *SO* the day-ahead and week-ahead hourly MW production. The forecasts shall be provided by each V*RPP* by 1400 Hr on a daily basis for the following seven (7) days for each half-hour time period, by means of an electronic interface in accordance with the reasonable requirements of the *SO's* data system.

Each VRPP shall also have the capability to produce and submit to the SO MW production forecasts every 3 hours at times to be determined by the SO for the following 12 hours for each 15- minute time period by means of the electronic interface in accordance with the SO's reasonable requirements.

8 OPERATIONS CODE NO. 1 – OPERATIONAL PLANNING

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

8.1 EAPP IC REQUIREMENTS

8.1.1 Introduction

To gain maximum benefit from the *EAPP Interconnected Transmission System, Outage* requirements for generation and transmission facilities and other factors likely to affect the operation of the system shall be coordinated between *TSOs* and *EAPP CC* for a period of three (3) years ahead down to real-time. In formulating *Outage* placement proposals account shall be taken, where appropriate, of any commercial agreements entered into which impose constraints on *Outage* duration and or placement.

In accordance with the terms of the Planning Chapter of the *EAPP IC*, the *TSOs* and the *EAPP Sub-Committee on Planning* are required to produce a *Power Balance Statement* and a *Transmission System Capability Statement* on an annual basis for the succeeding ten (10) years. The *Transmission System Capability Statement* forms the basis for individual *Users* of *National System*s to determine the potential for power transfers within the *EAPP Interconnected Transmission System*.

Operations Code No. 1 (OC 1) sets out a refinement of the planning process to take account of the following:

(a) *Outage* requirements for generation and transmission facilities whether for construction, maintenance or operational tests or *System Tests*;

(b) Changes in the characteristics of generation or transmission facilities;

(c) Changes in demand estimates;

(d) Changes in *Generating Unit* availability caused by breakdown, fuel shortage or hydrological conditions;

(e) Current and forecast weather conditions;

(f) Anticipated commercial energy flows across the *EAPP Interconnected Transmission System*, and

(g) Other information supplied by *TSOs* or *Users*.

The outcome of the *Operational Planning* process will be a definition of the *Power Balance* and *Transmission System Capability* over various time scales.

TSOs are responsible for liaison with the *Users* connected to their *National System*s in respect of the *Operational Planning* process.

8.1.2 Objective

OC1 specifies:

(a) The requirements for the exchange of information across the *TSO-EAPP* interfaces throughout the *Operational Planning* process, from *Outage requirements* identified up to three (3) years ahead for complex schemes and *EAPP Interconnected Transmission* and *National System*s reinforcement to hand over of the *Operational Plan* into the Control Phase;

(b) The *Operational Planning* procedure including information required and a typical timetable for the coordination of *Planned Outage* requirements for *Generating Units* and transmission facilities including protection and associated communication channels that may have an effect on the operation of the *EAPP Interconnected Transmission System*, and

(c) The coordination of *Outages* to minimise as far as possible the number and effect of constraints on the *EAPP Interconnected Transmission System*.

8.1.3 Scope

OC1 applies to *TSOs* and to *EAPP CC*. It should be noted that certain information and data may be required from individual *Users* and also from *External Systems*. It is the responsibility of individual *TSOs* to ensure such information and data is updated and made available.

8.1.4 Planning Cycle

The phases of the *Operational Planning* process are as follows:

(a) The *Operational Planning* Phase covering planning of the *EAPP Interconnected Transmission System* for the succeeding three (3) years;

(b) The *Programming* Phase covering planning for the operation of the *EAPP Interconnected Transmission System* for the period of one (1) to eight (8) weeks ahead; and

(c) The *Control* Phase involving immediate *Operational Planning* for the day-ahead.

8.1.5 Outage Planning Process

There are four main inputs to be considered in carrying out the *Outage* planning process:

8.1.5.1 Demand Forecast

By the end of October each year, *TSOs* shall provide the *EAPP CC* with the projected maximum and minimum demands on their *National Systems* for the three (3) years ahead on a monthly basis. The demand forecast shall be specified for each substation of the *EAPP Interconnected Transmission System* within each *National System*.

By 1000 Hr each Friday, *TSOs* shall provide the *EAPP CC* with hourly demand forecasts for the following eight (8) weeks on each node of the *EAPP Interconnected Transmission System*. The demand forecasts shall include *Active* and *Reactive Power* requirements for each sub-station that is part of the *EAPP Interconnected Transmission System*.

The *EAPP* demand forecast shall normally be based on the aggregate of individual *TSO* forecasts. Nevertheless, the *EAPP CC* may carry out its own forecast using its own criteria if it has doubts on the validity of the individual *TSO* forecasts. If in the event there are significant differences between the aggregated *TSO* forecasts and the *EAPP* forecast, the *EAPP CC* shall prepare a report on the reasons for any discrepancies for presentation to the *EAPP Sub-Committee on Operations* to determine the matter.

TSOs shall provide the *EAPP CC* with estimates of the load which could be disconnected if required. Details shall be given of the load shedding blocks and procedures required to implement load shedding in accordance with OC 5 as in Chapter 12 (Operations Code No. 5 - Demand Control). Details shall also be provided of the *Automatic Load Shedding Scheme* installed in the *TSO's National System*.

8.1.5.2 Generating Unit Outages

Generating Unit Outages shall be planned such that any *Outage* shall not jeopardise the security of operation of the *EAPP Interconnected Transmission System*. Particular attention is required for large

Generating Units and those having a major impact on the *Reactive Power* requirements of the *EAPP Interconnected Transmission System*.

By the end of October in each calendar year, *TSOs* will provide the *EAPP CC* with:

(a) Draft *Provisional Generating Unit Outage Programme* for Years 2 and 3 for its centrally despatched *Generating Units*;

(b) F*inal* Generating *Unit Outage Programme* for Year 1 for its centrally dispatched *Generating Units.*

Between October and December of each calendar year, *EAPP CC* will consider the implications of the draft *Provisional Generating Unit Outage Programmes* submitted on the *Operating Margin* and the security of operation of the *EAPP Interconnected Transmission System* and request modifications if necessary. The *Final Generating Unit Outage Programmes* for Years 1, 2 and 3 shall be published on the *EAPP* Website at the end of December each year.

8.1.5.3 Transmission Outages

The planning of transmission *Outages* is dependent on the schedule of *Generating Unit Outages* and on the contracted energy transfers between *Control Areas*. *TSOs* shall plan transmission *Outages* required in Years 2 and 3 as a result of construction or refurbishment works. It is not anticipated that any detail of *Maintenance Outages* on the *EAPP Interconnected Transmission System* will be available 2 or 3 years ahead.

The planning of transmission system *Outages* in Years 0 and 1 ahead will, in addition, take into account *Outages* required as a result of maintenance and or operational or *SystemTests.*

8.1.5.4 Net Transmission Capability

Certain *Users* may have pre-emptive rights over the use of *Transmission System Capability*.

This may occur where the *User* concerned has provided generation or transmission facilities as a consequence of a bilateral agreement. The *TSO* shall notify the *EAPP CC* of the existence and extent of such agreements for *Operational Planning* purposes.

In carrying out *Operational Planning* the capacity rights shall be taken into account in the placement of generation or transmission *Outages*. However, the security of the *EAPP Interconnected Transmission System* shall be the overriding consideration.

The method of calculation of the Net Transmission Capability is set out in Section 14.1.3, Determination of Transmission Capability.

8.1.6 Outage Planning Philosophy

Transmission system *Outages* and *Generating Unit Outages* shall be coordinated so that, in general, *Generating Unit Outages* shall take precedence over transmission system *Outages*.

The *EAPP CC* and each *TSO* shall seek to resolve any *Outage* placement conflicts through collaboration with each other, any relevant *Users* and *External Systems*.

The philosophy of *Outage* co-ordination associated with the *EAPP Interconnected Transmission System* shall ensure that:

(a) *Maintenance* and construction *Outage* programmes of transmission *Plant* and *Apparatus* are co-ordinated to minimise the loss of *Transmission System Capability*;

(b) *Planned Outages* of system voltage regulation equipment, such as *Automatic Voltage Regulators*, synchronous compensators, shunt and series capacitors and reactors, shall be coordinated as required between *TSOs* by *EAPP CC*;

(c) *Unplanned Outages* associated with transmission *Plant* and *Apparatus* are completed so as to restore normal operating conditions as quickly as possible. In the case of *Unplanned Outages*, *TSOs* shall consider the possibility of undertaking maintenance work during the *Unplanned Outage* such as to minimise subsequent *Outage* requirements or improve *EAPP Interconnected Transmission System* reliability;

(d) Information is exchanged identifying maintenance work which has or could have a direct impact on the operation or transfer capability of the *EAPP Interconnected Transmission System*;

(e) Risks of Trip of transmission elements and *Generating Units* are to be planned according to the same rules as for *Outages*, and

(f) Routine maintenance of metering, telemetering, control equipment and associated communication channels shall be coordinated between *TSOs* and *EAPP CC*.

8.1.7 Data Requirements

The provision of a uniform data base of the *EAPP Interconnected Transmission System* and forecasts for interchange scheduling will allow each *TSO, EAPP Sub-Committee on Operations* and *EAPP CC* to perform power system studies for the simulation of:

(a) The effects of *Generating Unit Outages* on power flows, both on *National Systems* and on the *EAPP Interconnected Transmission System*, and

(b) Load flows associated with the *Outage* of lines or other elements of the *EAPP Interconnected Transmission System*, taking into consideration the influence of *Neighbouring* and *External Systems*.

8.1.8 Operating Planning Phase

The *Operational Planning* Phase is concerned with the planning of generation and transmission *Outages* on the *EAPP Interconnected Transmission System* for the succeeding three (3) years.

By the end of October in each year, each *TSO* shall prepare a draft *Maintenance Plan* covering the period up to three (3) years ahead for discussion with *EAPP CC* and other*TSOs*. *TSOs* shall notify each *User* of those aspects of the draft *Maintenance Plan* which may operationally affect such *User* including, in particular, proposed start dates and end dates of relevant *EAPP Interconnected Transmission System Outages*. The *TSO* shall indicate to a *Generation Licensee* where a need may exist to impose restrictions on the operation of *Generating Units* to allow the security of the *EAPP Interconnected Transmission System* to be maintained.

The development of the draft *Maintenance Plan* is an iterative process requiring frequent *EAPP CC* and *TSO* liaison. Each *TSO* shall review the draft *Maintenance Plan* on an ongoing basis and provide *EAPP CC* with *Outage* change requests as they become known to that *TSO*, taking account of known or advised *User Outages*.

By the end of December in each year, the draft *Maintenance Plan* will be confirmed and will become the Annual *Maintenance Plan* for the immediate year ahead (Year 1).

8.1.9 Programming Phase

During the Programming Phase, *TSOs* and the *EAPP CC* shall refine, optimise, and update the Annual *Maintenance Plan* to accommodate essential changes, additional work and previously unconfirmed *Outages*, taking into account transmission and generation profile changes.

In the Programming Phase, *Operational Planning* is carried out on a rolling eight (8) week cycle. Each Friday *TSOs* shall update the Annual *Maintenance Plan* for the following eight (8) week period beginning at 0001 Hr on the following Monday.

The *Outage* Plan for the eight (8) week period ahead will determine the transmission constraints which impact on the *Transmission System Capability*. Agreed final *Outages*, as published in the Annual *Maintenance Plan*, are only to be amended if a changed requirement is brought about by an unplanned event on the *EAPP Interconnected Transmission System*.

Users shall give as much notice as reasonably practicable of any *Outages* affecting the *EAPP Interconnected Transmission System*. Any short notice *Outage* on the *EAPP Interconnected Transmission System* which could not be planned with ten (10) days' notice is considered to be an *Unplanned Outage.* A *Planned Outage* is an *Outage* for which at least ten (10) days' notice has been given.

Any variation in the planned return to service date or *Outage* start and completion times shall be brought to the notice of any other *TSO* involved and the *EAPP CC* immediately it is foreseen. The matter will be discussed between the respective *TSOs* and the *EAPP CC* in order to agree a new return to service date and or *Outage* start and finish times.

Where a *TSO* or the *EAPP CC* is obliged to cancel a *Planned Outage* in order to safe guard the operation of the *EAPP Interconnected Transmission System*, the *Outage* will be re-planned so as to minimise any adverse impact on either the *User* or *TSO* concerned.

8.1.10 Control Phase

Each day at 1500 Hr, *EAPP CC* and *TSOs* shall issue the final *Operational Plan* for use in real-time. This *Operational Plan* will cover the 24-hour period commencing at 0001 Hr onthe following day. In the case of the *Operational Plan* issued on a Friday, the Plan will cover the three (3) days commencing at 0001 Hr on the Saturday. To minimise disruption to the existing programme and resources *Outage* changes in this period shall be limited to those deemed essential.

The *Operational Plan* shall contain details of any additional security studies, temporary protection settings and changes to operational arrangements to facilitate an *Outage* and agreements for operational actions including emergency return to service time, demand and Generating *Unit* inter-trip requirements and demand transfers. Any resource requirement for local switching shall be confirmed between relevant *TSOs*.

The *Operational Plan* will contain details of all *Outages* of *Generating Units* and transmission facilities, details of anticipated transfers, transmission constraints, *Contingency* plans and any other relevant information.

8.1.11 Records

TSOs and *EAPP CC* shall keep records of:

(a) The availability of *Generating Units* and transmission facilities;

(b) The duration and reasons for unavailability, whether planned or unplanned;
(c) The changes requested for planned *Outages* in the *Operational Planning* process, and
(d) The cost of any constraint imposed by unavailability.

These records shall be made available to the *EAPP Steering Committee* and to the *Independent Regulatory Board* upon request.

8.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

8.2.1 Introduction

The *SO and TNSPs shall* use the following guidelines in developing procedures for their operations planning, wherever applicable.

8.2.2 Operating Procedures

(a) The *SO and TNSPs shall* develop and maintain operating procedures for the safe operating of the *Kenya National Transmission System (KNTS),* and for assets connected to the *KNTS*. These operating procedures shall be adhered to by *Users* when operating equipment on the *KNTS* or connected to the *KNTS*.
(b) Each *User shall* be responsible for their own safety rules and procedures. The *SO and TNSPs* shall coordinate to ensure the compatibility with regard to the safety rules and procedures of all *Users*.
(c) In case of any equipment fault impacting the *KNTS*, *Users* must report such faults to *the SO* immediately, or in the shortest possible time. Details of such faults should be reported as soon as possible, but no later than fourteen (14) days for the purpose of post-fault analysis in order to determine causes and remedial action plans. Details regarding the fault shall include such information as: (1) date, time, and location of fault; (2) cause of fault; (3) switching operation(s); (4) injuries/damages; (5) interruptions and duration of interruptions; and (6) any other information, as appropriate. *The SO* shall record and maintain all relevant information pertaining to all faults on the *KNTS*.
(d) The EAPP operational agreements shall apply in the case of operational liaison with all international power systems connected to the *KNTS*.

8.2.3 Operational Liaison, Permission for Synchronisation

(a) The *SO shall* sanction the switching, including shutting down and synchronising, of units and changing over of auxiliaries on all units.
(b) If any *User experiences* an emergency, the other *Users* shall assist to an extent as may be necessary to ensure that it does not jeopardise the operation of the networks/plant.
(c) A *User* shall enter into an operating agreement with the *SO* and the *TNSPs* if it is physically possible to transfer load or embedded *Generating Plants* 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 load transfers.

8.2.4 Safety Coordination

*TNSP*s shall authorise only competent and authorised staff to carry out any work such as network switching on the transmission grid and at the *Connection Point* for *Generating Plants* and non-embedded *Customer*s. *TNSPs shall* be the custodian of safety procedures and documents used when working on plant and/or equipment on the transmission grid and at all points of connection with the *Users*. *TNSPs shall* not impose these safety requirements for work outside the *KNTS* and beyond the points of connection. *TNSPs* and *Customer*s both shall maintain clearly written switching logs in chronological order for all switching operations and document messages relating to safety co-ordinations. Repository of the switching logs and safety documents are maintained by the *SO*.

A list of authorised personnel for transmission grid and for *Users* at points of connection with names, designations, and telephone numbers shall be made available to the *SO* and the *KNTS Users*. The list must be updated and re-circulated as and when there is any change of information.

(a) The designated and authorised person shall ensure that adequate safety precautions are established and maintained when any work is done on plant and equipment. To ensure safety to commence work, the following steps shall be verified:
   (i) Source of power removed
   (ii) Device physically disconnected from source of power with a caution notice attached to it
   (iii) Safety testing completed satisfactorily
   (iv) Proper connection to the earth ensured
   (v) Safety documents issued
   (vi) The equipment shall only be considered suitable for return to service when all safety documents have been cleared and isolation points normalised.

(b) In the event of an accident during work on the *KNTS* or at points of connection, the following steps shall be taken:
   (i) Stop work and attend to the injured if any;
   (ii) Notify designated authorised person for decision on whether work should continue or not;
   (iii) Designated authorised person notifies *the SO*;
   (iv) Designated authorised person produces a preliminary report and notifies *the TNSP and the SO.*
   (v) *TNSP shall notify the Authority within 48 hours* ;
   (vi) The TNSP constitutes a committee for further investigation;
   (vii) The *TNSP* produces a detailed accident report and shares with the Authority;
   (viii) The *SO* circulates report internally and to key people in the *Users* systems.

(c) Authorised switching personnel for *TNSPs shall* have to be recertified every 3 years through simulating training/testing provided by the *SO.*

8.2.5 Communication

8.2.5.1 Safety Conditions

To achieve a high degree of service reliability, the *SO* shall ensure adequate and reliable communications with the *Users*. Communication regarding safety coordination shall be made via normal operational channels. Additionally, the *SO and Users shall* share official business contact telephone numbers at which operational personnel can be reached to be used for operational purposes, if required. The *SO* shall ensure proper recording and monitoring of all operational lines for future replay in case of any disputes or incident investigation.

8.2.5.2 Outage Conditions

The *SO* shall monitor and/or determine system conditions from time to time, and communicate these, or changes from a previous determination, to all *Users*.

The TNSP shall be responsible for providing *Users* with operational information including planned and forced *Outages* as agreed upon with the SO. Any changes or modifications to the existing transmission network and/or information regarding network condition that is likely to impact the short and long-term operation of the *Users* shall be communicated in a timely manner. Planned *Outage* shall be deferred under the following circumstances:

(a) Grid disturbances
(b) System isolation
(c) Partial blackout on the *KNTS*
(d) *Upon request by the User or TNSP.*
(e) Any other event that may have an adverse impact on the system.

*Generation Licensee*s shall provide the *SO*:

(a) A 52-weeks-ahead *Outage* plan per *Generating Plant*, showing *Planned Outage* and return dates and other known generation constraints, updated weekly by 1500 Hr every Monday (or first working day of the week).
(b) An annual maintenance/*Outage* plan per *Generating Plant*, looking five (5) years ahead, showing the same information as above and issued by 31stDecember of each year.
(c) A monthly variance report, explaining the differences between the above two plans.

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

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

(a) Maintaining adequate reserve levels at all times;
(b) Ensuring reliability where transmission constraints exist;
(c) Maintaining acceptable and consistent real-time technical risk levels

The application for an equipment *Outage*, complete with duration of the *Outage*, work details, extent of isolation, switching programme and personnel to be involved, shall be made by the *User* to the*SO* in a timely matter, but not later than seven (7) days prior to the due date of intended *Outage*. The *SO shall* evaluate the request as per the established approval procedure for *Outages.* The information regarding the *Outage* request shall be communicated back to the requester through established channels/modes of communication. Approved *Outages* shall be entered into the appropriate log as an official record of planned system *Outages*. Applicants shall be notified via established channels of communication concerning the approval, rejection, or deferment of *Outage* applications.

The *SO* shall also report daily demands, energies, losses, interruptions, etc. to *Users* and archive the information. The historical information shall be available to all *Users* on request.

8.2.6 Logs

An operational message, instruction or a report sent/received on email, radio, telephone, cell phone or carrier by the *SO*, *TNSP*s, or *Generation Licensee*s shall be logged with all the necessary details, as listed below:

(a) Name of the station information is sent to/received from.

(b) Exact time information was sent/received.

(c) Name of the person sending/receiving the information.

(d) Exact time of completion of carrying out the instruction.

(e) The name of the operator, the date and time and serial number.

8.2.7 Operational Planning

If a daily generation dispatch needs to be developed, it shall be done following the procedure guidelines shown below:

A dispatch form is created by the *SO* with the date/time of the dispatch and is archived. Expected half-hourly country demand is estimated using historical demands for the particular day. Available *Generating Plants* are scheduled in half hour increments to meet forecast demand based hydro energy targets, spinning reserve and other *Ancillary Service* system security and merit order requirements. The generation schedules is evaluated to determine if country demand, *Spinning Reserve* and other *Ancillary Service* system security needs, main hydro target and merit order requirements have been met.

If the requirements have not been met, the system shall be re-dispatched until requirements have been met. The *SO shall* log the dispatch form, and customised copies of the dispatch forms shall be sent to relevant recipients.

8.2.8 Generation System Data Requirement

Generation outputs and equipment loadings shall be recorded on half hourly basis as per requirements in power purchase agreements (PPA). *Generation Licensees'* fuel data and energy *Meter* readings shall be taken after every midnight. Machines loading/shutdown, trip or output limitations data/reports shall be done immediately after information is received at the *SO*. Data recording and reporting shall be done following the guidelines below:

(a) *Meter* reading of appropriate data (including plant loading/voltage levels, fuel storage, etc.) is taken in the field at pre-determined intervals of time, and logged.

(b) Data is then validated at the *Generating Plant* for accuracy/metering errors, and corrected. The field readings of half hourly data shall be passed to the *SO* at appropriate intervals of time. Plant shut down, operational limitations and other constraints are reported to the *SO* along with the *Meter* readings, and appropriately logged.

(c) For hydrology data, dam levels received from hydro stations shall be recorded on hourly basis or appropriate intervals.

(d) For *Generating Plant* output/equipment loading data, half hourly outputs and relevant equipment loadings shall be logged.

(e) For Generating *Plant* loading/shutdown time data, the generating plant loading/shutdown times shall be logged.

(f) For system voltages, half hourly readings of system voltages from *SCADA* mimic display shall be taken and logged.

(g) For *Generating Plant* capacity availability data, half hourly capacity availability for *Generating Plants* shall be logged.

(h) For midnight energy *Meter* readings for *Generating Plants*, end of day *Energy Meter* readings shall be logged every midnight.

(i) For fuel stock for *Generating Plants*, end of day fuel stocks for diesel plants shall be logged. *Generating Plants* shall pass the fuel stocks to the *SO* after every midnight.

(j) For Generating *Plant Outage*/Capacity reports, details of *Outage*s or operation limitations shall be logged. Report forms shall be filled whenever a machine trips, is shut down on emergency or it has operational limitations.

(k) The *SO* shall check to confirm that data received is correct and has been entered correctly in the log sheets.

(l) Required corrections in data entries shall be made.

(m) If no corrections are required, reports shall be processed and an accurate and complete daily analysis report prepared, archived, and printed.

8.2.9 Transmission System Data Requirement

The capability of transmission system components for both normal and emergency conditions shall be established by technical studies and operating experience. System operation shall be co-ordinated among systems and control areas (national/regional). This includes coordination of equipment *Outage*s, voltage levels, *MW* and *Mvar* flow monitoring and switching that affects two or more systems of transmission components. When line loading, equipment 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. Refer to Chapter 10 (Operations Chapter No. 3 - Emergency Operations) for more details.

9 OPERATIONS CODE NO. 2 – OPERATIONAL SECURITY

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC* If in any instance there is a difference in requirements, the more stringent requirement shall hold.

9.1 EAPP IC REQUIREMENTS

9.1.1 Introduction

Operations Code No. 2 (OC 2) is concerned with security aspects in the *Operational Planning* and real-time operation of the *EAPP Interconnected Transmission System* and does not deal with long-term planning for which reference should be made to Chapter 5 (Planning). OC2 is not concerned with the commercial aspects of system operation.

System security and reliability are primary goals of the operation of the *EAPP Interconnected Transmission System*. Each *TSO* is responsible for the operation of its *National System* but the interrelationship between that system and the *EAPP Interconnected Transmission System* requires coordination by the *EAPP CC* at regional level.

Pending full interconnection between all countries of *EAPP*, the *EAPP Interconnected Transmission System* shall be operated in a number of *Control Areas*. A *Control Area* comprises various *National Systems* or parts of *National Systems* capable of regulating its *Generating Units* in order to meet its constantly changing demand and to maintain its interchange schedule with other systems or *Control Areas* and contributing its frequency bias obligation to the interconnection. Each *Control Area* shall have one of the *TSOs* designated as *Control Area Operator*. The designation of the *Control Area Operator* shall be agreed with the *TSOs* concerned and with the *EAPP CC*.

The *Control Area Operator* shall ensure that within its *Control Area* sufficient reserves of generation are available to allow for continuous generation and load balancing, frequency control and the maintenance of *EAPP* operational security standards as described in OC2. Any failure to meet these minimum requirements can lead to reduced security or to disturbances or events causing undesirable effects on the *EAPP Interconnected Transmission System*.

OC 2 specifies the technical requirements and standards for the operational security of the *EAPP Interconnected Transmission System* as they relate to the following issues:

(a) N-1 *Contingency* criterion;
(b) Interchange scheduling;
(c) Operating reserves for control of system frequency and interchange with other *Control Areas* or *External Systems*;
(d) Voltage control;
(e) Fault level control;
(f) Protection coordination, and
(g) *Remedial Action Schemes*.

9.1.2 Objective

The objectives of OC 2 are:

(a) To provide a framework of principles and requirements for achieving and maintaining the security and reliability of the *EAPP Interconnected Transmission System* during operation of the system under normal and emergency conditions, and

(b) To ensure that the *EAPP Interconnected Transmission System* is operated within the technical parameters set out in Chapters 5 and 6 (Planning, and Connections).

9.1.3 N-1 Criterion

The N-1 security criterion refers to the requirements placed upon the operation of the *EAPP Interconnected Transmission System* to maintain the security of the system during normal and disturbed conditions.

This criterion shall be applied by all *TSOs* in combination with appropriate choice of generation, transmission facilities, and sufficient active and reactive reserves. *TSOs* shall identify by means of *Operational Planning* potentially insecure situations in order to take appropriate measures in advance.

Control Area Operators are responsible for the application of the N-1 Criterion throughout their *Control Area*.

9.1.3.1 Contingency

The loss of any element of the *EAPP Interconnected Transmission System* shall not cause:

(a) A frequency deviation outside operating limits;

(b) A voltage deviation leading to voltage instability;

(c) Thermal overloading of equipment;

(d) Islanding of any part of the *EAPP Interconnected Transmission System*;

(e) Angular instability in the *EAPP Interconnected Transmission System*, and

(f) Cascading *Outages*.

It is acceptable in some cases for *TSOs* to allow for loss of load on condition that its magnitude is compatible with secure operation and is predictable and locally limited. The following normal *Contingencies* shall be considered:

(a) A single transmission line;

(b) A single *Generating Unit* or combination of *Generating Units*;

(c) A single transformer;

(d) A voltage compensation installation;

(e) An *HVDC* link considered as either a *Generating Unit* or a *End-user.*

TSOs shall also take account of multiple *Contingencies* when such *Contingencies* may occur with sufficiently high probability to threaten the security of operation. Examples of such multiple *Contingencies* are:

(a) A double circuit line, which refers to two circuits on the same towers over a considerable distance;

(b) A single busbar, during periods when the *TSO* assesses there is asignificantly higher risk of *Outage*;

(c) A common mode failure with the loss of more than one *Generating Unit*.

The *Contingency* monitoring process includes the loss of single or multiple elements of generation or transmission equipment at any time. This monitoring shall also take account of temporary weather conditions or temporary limitation of transmission facilities.

9.1.3.2 Responsibilities

It is the responsibility of each *TSO* to monitor the N-1 Criterion on its own *National System*, to carry out computer simulations for *Contingency* analysis and to notify the *EAPP CC,* the *TSOs* of *Neighbouring System*s and *External Systems* of potential problems in the application of the criterion. The *TSOs* concerned shall jointly verify the compliance with the N-1 criterion taking into consideration cross-border power transfers.

After a *Contingency*, each *TSO* shall return its power system to N-1 compliant condition as soon as possible and in case of a delay, it shall immediately notify the *EAPP CC* and all other *TSOs* affected.

9.1.4 Interchange Scheduling

The net amount of interchange scheduling between *National Systems* or *Control Areas* shall not exceed the mutually agreed transfer limits of the *EAPP Interconnected Transmission System*.

The entire *EAPP Interconnected Transmission System* shall be operated in such a way that sufficient transmission capacity is available for the delivery of reserve power for *Primary Response* for the *National Systems* or *Control Areas* which may be affected by the most severe single *Contingency*.

Requirements for interchange scheduling on the *EAPP Interconnected Transmission System* are set out in the Interchange Scheduling and Balancing Chapters 14 through 16.

9.1.5 Operating Reserves

TSOs shall continuously maintain adequate reserve generating capacity to control the frequency of the *EAPP Interconnected Transmission System* within the limits set out in Chapter 6 (Connections), and to avoid unexpected loss of load following transmission or generation *Contingencies*. The reserve generating capacity is also required to maintain agreed interchange schedules following changes in demand or generation. The requirements for operating reserve on the *EAPP Interconnected Transmission System* are set out in the Chapter 15 (ISBC Chapter No.2 Balancing and Frequency Control.)

9.1.6 Voltage Control

9.1.6.1 Basic Principles

To maintain the *EAPP Interconnected Transmission System* security and integrity, and avoid damage to transmission and *User's* equipment, each *TSO* shall maintain voltages within the limits set out in Section 6.1.4 in Chapter 6 (Connection) and shall contract for voltage control *Ancillary Services* in accordance with Chapter 16 (ISBC Chapter No. 3 -Ancillary Service Chapter).

Each *TSO* shall operate reactive resources within its *National System* to maintain system and interconnection voltages within limits. Each *TSO* shall maintain reactive resources to support its voltage under N-1 *Contingency* conditions and shall disperse and locate the reactive resources so that they can be applied promptly and effectively when *Contingencies* occur. The *TSO* shall direct corrective action, including load shedding, necessary to prevent voltage collapse when reactive resources are insufficient.

Reactive Power flows on the *EAPP Interconnected Transmission System* shall be maintained at a minimum level in order to limit voltage drop and to allocate the total*Transmission System Capability* mainly to *Active Power*. In the event that sufficient reactive resources are not available within a *TSO*'s *National System*, bilateral agreements may be made with *Neighbouring Systems* to transfer *Reactive Power* through cross-border connections.

9.1.6.2 Responsibilities

Each *TSO* individually and jointly with other *TSOs* and the *EAPP CC* shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAr flows within their *National Systems* and with *Neighbouring Systems*.

Without limitation, the procedures shall include the following methods of voltage control:

(a) Adjusting *Generating Unit Reactive Power* output;

(b) Transformer tap changing, cable switching, reactor and capacitor switching, and other control methods;

(c) Tap changing on *Generating Unit* transformers;

(d) Scheduling must-run generation, and

(e) Switching out of transmission lines.

TSOs shall ensure that data on all generation and transmission *Reactive Power* resources, including the status of voltage regulators, tap changers and *Power System Stabilisers,* is available to neighbouring *TSOs* and the *EAPP CC*.

9.1.7 Fault Levels

The *EAPP Interconnected Transmission System* is subject to short circuits between phases or to earth mainly due to atmospheric conditions and to faults in equipment. Short-circuit protective devices are installed on all system equipment in order to promptly and effectively disconnect any fault with selectivity.

TSOs shall ensure that the setting and function of the protection equipment is checked regularly. If there are significant changes in operating conditions, the settings of protection devices shall be adjusted to suit the new conditions.

9.1.7.1 Standards

Each *TSO* shall operate its *National System* such that, at any node of the *EAPP Interconnected Transmission System*, short-circuit currents do not exceed the breaking capacity of the switchgear installed at that node, so that failure to clear a fault does not lead to cascading *Outages*. The *TSO* shall use an appropriate protection strategy as set out in Chapter 6 (Connections) to ensure selectivity and to provide backup protection in case of failure of the main protection system to isolate a fault.

9.1.7.2 Corrective Action

In the event of fault levels exceeding permissible levels at any particular location, *TSOs* shall take immediate action to manage the values within limits.

Each *TSO* shall calculate where appropriate the short-circuit currents at each node of its *National System* taking into account the contributions of *Neighbouring System*s to the short circuit current. *TSOs* of *Neighbouring Systems* shall exchange the data required for short circuit calculations.

In order to limit fault levels in operational time scales, *TSOs* have a number of options including the switching out of lines and the operation of busbars in separate sections. However, *TSOs* shall take into account the operational security standards when considering such measures.

9.1.8 Protection Coordination

TSOs and the *EAPP CC* shall coordinate the application and maintenance of protection systems on the *EAPP Interconnected Transmission System*. Protection systems shall be used to detect abnormal system conditions and to trip selectively circuit breakers on generation and transmission facilities to prevent danger to persons or damage to equipment.

Each *TSO* and the *EAPP CC* shall ensure that its *Control Centre* personnel are familiar with the purpose and limitations of the protection system schemes applied in the *EAPP Interconnected Transmission System*. Power system protection procedures shall be made available to all appropriate system personnel and shall provide for instructions and training where applicable.

The procedures shall cover the following:

(a) Planning and application of protection systems;

(b) Review of protection systems and settings;

(c) Intended operations under normal, abnormal and emergency conditions;

(d) Regular scheduled testing and preventive maintenance, and

(e) Analysis of the actual protection system operation.

9.1.9 Requirements

Since protection systems in one *National System* can affect operations in *Neighbouring Systems*, all protection systems in the *EAPP Interconnected Transmission System* shall be co-ordinated between *Users* and the relevant *TSOs*. Protection systems on transmission interconnections with *External Systems* shall also be coordinated to prevent operational problems which may impact on the *EAPP Interconnected Transmission System*.

Each *TSO* shall supervise the status of its protection system and notify all relevant neighbouring *TSOs* of every change in status.

Each protection device shall be tested and recalibrated as necessary at least once a year. A review of the protection settings shall also be carried out whenever there is an expansion or change to the transmission or generation facilities. Any incorrect operation of a protection device shall be reported in accordance with OC4, Chapter 11 (Operating Code No.4 – Incident Reporting), investigated immediately and corrective action implemented as soon as possible.

Neighbouring *TSOs* shall be notified in advance of changes in generating sources, transmission, load or operating conditions, which may require adjustments to their protection systems.

9.1.10 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, generation units or transmission facilities under a set of carefully defined conditions. *RAS* are normally used in order to increase *Transmission System Capability* under specified conditions. They may also be used to permit higher loading levels on the *EAPP Interconnected Transmission System* in those instances where additional facilities cannot be built or have been delayed. Their application is specific to particular circumstances.

RAS installed on the *EAPP Interconnected Transmission System* shall be subject to agreement between the relevant *TSOs* and the *EAPP CC* unless the automatic actions following operation of *RAS* are confined to the area of a single *TSO*. *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 *TSOs* and *Users* involved.

*TSO Control Centre*s shall monitor the status of all *RAS* and notify all relevant *TSOs* and the *EAPP CC* of any change of status.

9.1.11 Power System Monitoring

Each *TSO* shall maintain *Power System Security* by monitoring the status of its *National System* and of relevant parts of the *EAPP Interconnected Transmission System*. *TSOs* shall therefore ensure that their *Control Centre*s and the *EAPP CC* are able, as a minimum, to monitor in real-time the following information:

(a) System frequency;
(b) Transmission line status;
(c) *Active* and *Reactive Power* flow on transmission circuits and across *User Connection Points*;
(d) *Active* and *Reactive Power* from *Generating Units*;
(e) Voltages at transmission and generation busbars;
(f) Dynamic and static *Reactive Power* reserves, and
(g) Appropriate alarms including overload and protection alarms.

Each *TSO* shall agree with neighbouring *TSOs* and the *EAPP CC* the real- time data to be exchanged on-line and its format.

In addition, each *TSO* shall provide computing facilities for:

(a) Evaluating *Contingencies* on the *EAPP Interconnected Transmission System*;
(b) Determining thermal, voltage and stability limits;
(c) Evaluating reserves of both *Active* and *Reactive Power*, and
(d) Carrying out post event analysis of power system incidents in accordance with OC 4, Chapter 11 (Operating Code No. 4 -Incident Reporting) with the aid of recorded data.

9.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

This section specifies guidelines to be used in developing criteria and procedures to be applied by the *SO* for operational security of the *Kenya National Transmission System (KNTS).*

9.2.1 Additional Responsibilities

9.2.1.1 Auxiliary Supply

The auxiliary supply to all *Generating Plant*s shall be regarded as the most important load on the *KNTS*. The *SO* shall regard all essential supplies as identified by the *Distribution Licensees* as having the same priority.

9.2.1.2 Supply Restoration

The *SO* shall be responsible for efficient restoration of the *KNTS* after supply interruptions.

9.2.1.3 Continuity of Operation

The *SO* shall ensure continuous operation of the *KNTS*.

9.2.1.4 Switchgear Operation

Any time that switchgear for a main or auxiliary system in the *KNTS* is to be operated, the *SO shall* approve the switching sequence for such operation including equipment identification. *TNSPs* shall follow procedures on the instructions.

If the *TNSP* has no objections, the procedures for the switching sequence shall be followed.

The *TNSP shall* carry out switchgear operation as instructed as expeditiously as possible. Whenever switchgear interlocks exist, the *TNSP* shall carry out an operation to defeat inter-locks before performing switchgear operation. Interlocks should not be defeated except under emergency or extreme circumstances and then only by senior authorised operational crew.

The *TNSP* shall inform the *SO* of completion of carrying out switchgear operation.

The *SO* shall write down the exact time of operating the switchgear in the standard daily switching log sheet.

If the *TNSP* has objections to carrying out switchgear operations, the *TNSP* shall inform the *SO*, and the *SO* shall investigate the matter.

In case of stressed switchgear noticed through alarm or physical observation, the *SO shall* be informed by the *TNSP*, and the *TNSP* shall follow appropriate actions as directed by the *SO.*

9.2.1.5 Equipment with Dual Responsibility

For equipment and its auxiliaries falling under the responsibility of both the *SO and* the *Designated Control Centres* (*DCC*), the *SO* shall identify the need to operate in dual control mode, and liaise with the respective *RCC* on the sequence of operations to be carried out.

The *SO shall* check and determine if there are any communication problems in the co-ordination of the operations.

If there are no communication problems, the *SO* shall co-ordinate switching operations.

If there are any communication problems in carrying out the operations, *SO* shall delegate co-ordination of operations to the respective *RCC*. The designated *RCC* shall co-ordinate the operations as delegated by the *SO*.

The designated *RCC* shall notify the *SO* of completion of carrying out required operations.

The *SO* shall log down the exact time of completion of carrying out the operations on the dual equipment.

9.2.1.6 Generating Plant Operation

Where there is a need for plant regulation/plant shutdown/plant loading identified by the *SO*, the appropriate *Generating Plant* operator shall be instructed to carry out the operational guidelines as listed below:

The need is identified by the SO from the system status as displayed by the *SCADA* system.The *SO* shall instruct the appropriate *Generating Plant* to carry out the required operation.

If there are no objections, the *Generating Plant* shall carry out required operation as instructed as expeditiously as possible.The *Generating Plant* shall inform *SO* of completion of carrying out required operation.

If there are objections, the *Generating Plant* shall notify the *SO and* the *SO* shall investigate the refusal to carry out the operation.

SO and the *Generating Plant* shall log the following information upon sending or receiving an operational message/instruction/report on radio/telephone/cell phone/carrier:

(a) Message, instruction or report details.
(b) Name of the station information is sent/received to/from.
(c) Exact time information was sent/received.
(d) Name of the persons sending/receiving the information.
(e) Exact time of completion of carrying out the instruction.

Generating Plant AVR'S and VAR limiter relays (where fitted) should be in service continuously. Whenever a *Generating Plant*is operating without its *AVR* or VAR limiter, the *SO* must be immediately informed.

The *SO* shall instruct the *Generating Plant* when to turn on and off and the *Generating Plant* shall comply. When the *Generating Plant* is on, it shall follow the *SO's* instructions regarding output (MW and MVArs).

Generating Plants shall not be taken out of service or rendered unavailable without reference to the *SO* except in cases of emergency when it should be informed as soon as possible of the action taken.

The *SO* shall as soon as possible be notified of any factors which may affect the output, efficiency or inflexibility of operation of any *Generating Plant.*

Free *Governor* action must be allowed within the prescribed limits whenever practicable to assist frequency control.

9.2.1.7 Loss of System Neutral Earthing

Any missing system neutral earthing noticed by the substation operator shall be immediately notified to the *SO*.

The *TNSP* on noticing a missing neutral shall immediately notify the *SO*giving details of the exact area missing the neutral earthing. The *SO*shall determine whether it is possible to restore the neutral earthing or not.

If it is possible to restore the system neutral earthing, the *SO*shall issue instruction to switch in the system neutral earthing.

The *TNSP* shall switch in system neutral earthing as fast as possible.

The *TNSP shall* inform the *SO*of completion of switching in neutral earthing.

If it is not possible to restore system neutral earthing, The *SO* shall quickly co-ordinate activities to make that part of the system without neutral earthing dead.

The *SO*shall log down exact time of switching in system neutral earthing.

9.2.1.8 Protection Equipment

In case there is any need to work on the system protection devices (e.g., relays, power supply, fuses, miniature circuit breakers, communication channel), the *TNSP* shall coordinate with the *SO*according to the operational guidelines below.

The *TNSP shall* inform the *SO*of the intention to carry out work on the protective apparatus. The *TNSP* shall also provide details of work to be carried out.

The *SO*shall assess the request and determine if work can proceed or not according to the following conditions:

(a) It is unsafe to work.
(b) There will be no adequate protection.
(c) There will be a disturbance in case of any tripping.

If none of the three cases exists the *SO*shall approve the request and inform the *TNSP* to proceed with work. Work shall be carried out in accordance with a procedure for such kind of work.

If any of the above conditions exist, the *SO*shall reject the request for work and inform the applicant of the rejection.

9.2.1.9 Transmission Line Fault

The *SO*shall develop and communicate formal procedures for correcting transmission line faults.

When breakers controlling a line trip due to a line fault, the *TNSP* shall coordinate with the *SO*as per the operational guidelines below:

The *SO*shall notice the unexpected trip from the *SCADA* and check to confirm whether the line has auto-reclosed or locked out. If line has auto-reclosed, the *TNSP* shall note the relays operated and distance of fault from the distance fault recorder and pass them to the *SO*. The *SO*shall log the relays operated and the distance of fault along with other information such as location of fault, identified by station, if possible; exact time of event; name of person working on the event; and exact time the fault was cleared. The incident shall be logged and relevant personnel shall be informed.

If line has locked out, the *SO*shall evaluate impact of the trip on the system by observing system response to the trip.

If there is any serious impact on the system, the *SO*shall take relevant appropriate action to stabilise the system.

If there is no serious impact as a result of the trip, the *SO*shall check to confirm with the *TNSP* if any work is being carried out on the line. If so, the *SO*shall determine if the fault is caused by the *TNSP*. If fault is caused by the *TNSP*, the *SOshall* instruct the *TNSP* to eliminate the cause of fault, and the *TNSP shall* notify the *SO*of the completion of eliminating the fault.

If no work is being carried out on the line, the *SO*shall check to confirm if line is from a manned substation or not. If the line is from manned substation, the *SO*shall issue instructions for reading and resetting relays and distance of fault from the distance fault recorder. If the line is from an un-manned substation, the *SO*shall direct the *TNSP* to the relevant substation. The *TNSP* shall note down relays operated, reset them and also record the distance of the fault from the fault recorder.

The *SOshall* check to confirm whether breaker-operating commands are available or not, and if so issue instructions for closing of line breakers. The *SO*shall close breakers controlling the line by sending a closing command using *SCADA*. If breaker-operating commands are not available, the *SO*shall issue instructions to the *TNSP* for closing of line breakers. The *TNSP* shall close circuit breakers controlling the line as instructed by the *SO*after selecting breakers on remote or local mode. The *TNSP* shall try a reclosure on the line and notify the *SO*of completion of carrying out a reclosure. If line holds, the *SO*shall check to confirm whether the line trips again or not. The *TNSP* shall notify the *SO*of completion of closing the breakers. The *SO*shall create, update and log the incident.

The *SOshall* inform relevant personnel about the incident.

If the line holds, the *SOshall* check to find out if any *Customer*s are interrupted as a result of the trip. If *Customer*s are interrupted and there is alternative source of supply, the *SO* shall transfer or co-ordinate activities to transfer *Customer*s to alternative source of power.

If no *Customer*s are interrupted or if they are interrupted and there is no alternative source of power, the *SO*shall check to confirm whether there is a switch along the transmission line or not. If there is an isolator along the line, the *SO*shall direct the *TNSP* to the isolator. The *TNSP* shall confirm arrival at the isolator, and the *SO*shall issue instructions to open the isolator on the line. Instruction shall be issued keeping in mind Electrical safety rules. The *SO*shall try a reclosure on the two line sections one after the other. If there is no trip, the *SOshall* issue instruction to close the isolator properly and normalise the line.

If there is no isolator along the line, the *SO*shall issue instructions to isolate the faulty section. Isolation of the fault shall be done by the *TNSP*, who shall open isolators controlling the affected section and securing them in open position as instructed by the *SO*. The *SO*shall notify the *TNSP* about the faulty part of the system.The *SO shall* log the incident.

The *TNSP* shall patrol the line to determine the fault. The *SOshall* wait for a report from the *TNSP.*

Upon finding the fault, the *TNSP* shall report to the *SO*details of isolations required for repairs to be carried out, *and* the *SOshall* issue instructions to isolate the location of the fault. The *TNSP* shall inform the *SO*of completion of carrying out isolations.

The *TNSP* shall carry out repair of fault using appropriate tools and shall notify The *SO*of completion of carrying out repairs.The *SOshall* issue instructions to normalise the line and the system.

The *TNSP* shall normalise line and system as instructed by the *Kenya National TSO*, and confirm of completion of normalising the system. The *SOshall* normalise and log the incident.

9.2.1.10 SCADA Equipment Failure

The *SO*upon detection of *SCADA* equipment failure shall first determine total or partial failure and then coordinate with the *DCC*s. Actions in case of a *SCADA* Equipment failure shall follow the operational guidelines below:

The *SO*shall establish whether it is a total or partial *SCADA* failure.

If partial failure, the *SO*shall assess the effects the failure has on generation, transmission and sub-transmission systems.

If a total failure, the *SOshall* instruct the *DCC*s to begin diagnosis, repair and restoration work. Upon the completion of the work the *DCCs* will inform the *SO*. The *SO*shall issue instructions to normalise the sub system and report back to the *SO*. In case of a total *SCADA* failure, the *SO*shall inform the *TNSP*s and the *DCC*s of the failure.

The *SO*shall instruct the *TNSP*s and the *DCC*s to monitor system parameters i.e. system Frequency and Voltage and report any significant variations/changes.

The *SO*shall instruct all *Generating Plants* and *TNSP*s to report any trip of a machine or line.

In case of a major disturbance on the *Kenya National Transmission System* affecting *SCADA* equipment:

(a) An incident shall be reported to the *SO*as soon as possible by *TNSP*s or *DCC*s with the following information: nature of incident; equipment affected; location of equipment; *Customer*s affected; and actions to be carried out. The *SO*shall evaluate whether incident has severe impact on the system.

(b) If there is a severe impact, the *SO*shall take the necessary appropriate action to ensure the integrity of the system, and determine if assistance is required or not.

(c) If assistance is required, the *SO*shall call relevant staff, inform them about the incident, and instruct them to call from desired locations.

(d) The *SO*shall check to find out if there are any casualties as a result of the incident. In case of any casualty, the *SOshall* call and inform the safety officer of the affected installation; location of the equipment; cause of the incident; and damage incurred.

(e) Depending on the impact caused, the *SO*shall make sure whether the incident is newsworthy. If it is newsworthy, the *SO*shall inform relevant communications officers of the following: nature of incident; affected installation; and affected *Customer*s.

The *Kenya SOshall* direct work for the identification of fault and repair. Upon completion of the work, the *SOshall* normalise the system and log the incident.

9.2.1.11 Access Security

The *SO*and Users shall have a detailed plan and procedures governing security and access to *User's SCADA*, computer, and communications equipment. The procedures shall allow for reasonable access to the equipment and information by the *SO*or its nominated representative for purposes of maintenance, repair, testing, taking of readings/measurements, and periodic checking as deemed necessary. *Users* shall ensure reasonable security against unauthorised access, use, and loss of information and a backup storage strategy for the systems that contain the information.

9.2.1.12 Hydro Generating Plants

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

9.2.1.13 Variable Renewable Power Plants

The *SO*shall ensure that VRPP ramp down their generation on consideration of the security of the *KNTS* or safety of any equipment or personnel. The *SCADA* facility shall provide appropriate information to the *SO*in this regard.

10 OPERATIONS CODE NO. 3 – EMERGENCY OPERATIONS

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC.* If in any instance there is a difference in requirements, the more stringent requirement shall apply.

10.1 EAPP IC REQUIREMENTS

10.1.1 Introduction

Operations Code No. 3 (OC 3) is concerned with maintaining the security and integrity of the *EAPP Interconnected Transmission System* in emergency operating conditions. Experience has shown that even a simple incident can trigger a large-scale disturbance which may have widespread implications for electricity supply to the population at large.

Although the *EAPP Interconnected Transmission System* may be designed and operated inline with the security standards set out in Chapter 5 (Planning) and the OCs, unexpected circumstances may arise where faults and disturbances outside the defined *Contingencies* may occur. Such circumstances require timely and decisive action to prevent further propagation of the disturbance. Disturbances can result from a number of causes but most typically may be due to the simultaneous loss of a number of *Generating Units* or transmission failures resulting from severe weather conditions or mal-operation of protection systems.

This is particularly the case where power systems today tend to be operated closer to the security limits due to environmental constraints and market pressures. The overriding principle is that the effects of faults and disturbances should be confined to as small a part of the *EAPP Interconnected Transmission System* as possible.

10.1.2 Objective

The objectives of OC 3 are to ensure that *TSOs* and the *EAPP CC*:

(a) Are able to identify insecure operating conditions on the *EAPP Interconnected Transmission System*;

(b) Have procedures and plans in place to manage emergency conditions;

(c) Have comprehensive contingency plans in place for the restoration of supplies in the shortest possible time using the most effective means.

10.1.3 Identification of Risks

TSOs and the *EAPP CC* shall ensure that they are in a position to identify the risk of insecure operating conditions either on their own *National System* or on the *EAPP Interconnected Transmission System*. The risks to secure operation of the *EAPP Interconnected Transmission System* may arise from but are not limited to the following:

(a) Flows on parts of the *EAPP Interconnected Transmission System* exceeding security limits;

(b) Lack of operating reserves (caused, for example, by *Outages* of *Generating Units*, by hydrological conditions or by restricted transmission capacities);

(c) Human error when carrying out switching operations on the *EAPP Interconnected Transmission System*;

(d) Frequency excursions outside normal operating limits;

(e) Significant *Reactive Power* constraints leading to critical high or low voltage conditions;

(f) High *Reactive Power* flows giving rise to potential protection mal-operations;

(g) Indications of instability such as voltage drop, undamped power swings or increase of phase angles;
(h) Lack of reliable real-time data, and
(i) Adverse climatic conditions.

10.1.4 System Warnings

TSOs and the *EAPP CC* require common definitions for NORMAL, ALERT, and EMERGENCY conditions to enable them to act appropriately and predictably as system conditions change. They should have a common understanding of each other's functions, responsibilities, capabilities, and authorities under emergency or near-emergency conditions.

10.1.4.1 Normal State

In its NORMAL state the *EAPP Interconnected Transmission System* is operating within its technical parameters. It has sufficient generation reserves, all transmission elements are operating within limits and voltage and frequency are normal.

In the event of identifying a risk of insecure operation a *TSO* or the *EAPP CC* may issue an ALERT or an EMERGENCY warning in real-time. These warnings shall be issued to all *Users* within a *TSO*'s *National System* and to the *EAPP CC* and any *Neighbouring System* which may be affected by the risk. Any warning issued by a *TSO* may be applied to the whole or part of its *National System* and by agreement with neighbouring *TSOs* to the whole of or part of their *National System*s. The *EAPP CC* may also issue warnings when in its view there is a serious risk to the whole *EAPP Interconnected Transmission System*.

10.1.4.2 Alert State

In an ALERT state, a *Contingency* has occurred but the *EAPP Interconnected Transmission* System is stable and all operational reserves for both transmission and generation balance have been committed. The *TSOs* and the *EAPP CC* may be uncertain as to when *the EAPP Interconnected Transmission System* can be returned to its NORMAL state due to system constraints and or low operating reserves and the situation is potentially dangerous.

10.1.4.3 Emergency State

In an EMERGENCY state the *EAPP Interconnected Transmission System* is in an unstable condition and phenomena such as cascade tripping, low frequency and or voltage, loss of synchronism, loss of supplies, whether partial or total, and islanding may occur. The security of the *EAPP Interconnected Transmission System* is endangered. Exceptional actions such as load shedding may be necessary to limit the spread of the dangerous phenomena and prevent the collapse of part of or the whole *EAPP Interconnected Transmission System*. In this state, the system passes rapidly towards dangerous conditions of operation with system parameters outside the limits fixed for secure operation.

10.1.5 Responsibilities of TSOs

TSOs and the *EAPP CC* shall draw up emergency plans and procedures and ensure that appropriate measures and resources are in place to enable the early identification of risks to secure operation of the *EAPP Interconnected Transmission System*.

TSOs shall act to alleviate emergencies and to implement emergency procedures in cooperation with neighbouring *TSOs* and the *EAPP CC*.

10.1.5.1 Real-Time Data

TSOs shall provide a *SCADA* system giving a complete overview of *TSO*'s *National System* and of relevant parts of *Neighbouring Systems*. The *SCADA* system shall be of dual redundant design with a back-up system in a remote location away from the *Control Centre*. The back-up system shall be subject to periodic testing to ensure its functionality.

The *Control Centre SCADA* system shall also provide facilities for post-mortem review to enable a detailed analysis of events and disturbances to be carried out.

Each *TSO* shall make available real-time data of relevant parts of its *National System* to neighbouring *TSOs* and the *EAPP CC*. Details of the data to be exchanged in real time shall be agreed between the parties.

TSOs shall ensure the provision of direct telephone lines to neighbouring *TSOs* and the *EAPP CC*.

10.1.5.2 Security Analysis

TSOs shall make arrangements to carry out studies of the effects of various *Contingencies* on the behaviour of the *EAPP Interconnected Transmission System* within their *National System*. These studies shall cover load flow, constraint analysis, static and dynamic stability and voltage stability. As a minimum such studies shall be carried out by each *TSO* in off-line mode on a weekly basis. In addition, real-time studies based on *SCADA* data should be carried out wherever possible.

The *EAPP CC* shall make arrangements to carry out a similar series of studies for the whole *EAPP Interconnected Transmission System*.

TSOs and the *EAPP CC* shall agree the list of *Contingencies* to be considered in carrying out the studies. The data required for the security analysis studies is contained in Section 19.8 of Chapter 19 (Data Exchange).

10.1.5.3 Coordination of Automatic Systems

TSOs shall ensure that procedures are in place for the coordination of automatic systems, including protection, having an effect on the system of a neighbouring *TSO* and shall agree on the type and the settings of devices for automatic tripping of cross-border connections.

10.1.5.4 Auxiliary Supplies

TSOs shall ensure that appropriate back-up auxiliary supplies are available at all substations and *Control Centre*s. These back up sources shall not rely upon a supply being made available from the *EAPP Interconnected Transmission System* and shall have a resilience of at least six (6) hours.

10.1.6 Emergency Procedures

TSOs and the *EAPP CC* have a primary obligation to maintain the integrity of the *EAPP Interconnected Transmission System* and to prevent any unplanned disturbance to the system. However, once a large-scale disturbance does occur they must be prepared to react and adapt to the dynamic environment of restoration operations.

Fundamental to re-establishing the integrity of the *EAPP Interconnected TransmissionSystem* is effective communications and coordination that enables *TSOs* and the *EAPP CC* to understand the nature of the disturbance as well as how one *TSO's* actions may impact on *Neighbouring Control Areas*. This communication and coordination is a continuous and evolving process tailored to the demands of the disturbance.

Each *TSO* and the *EAPP CC* shall develop, maintain and implement robust and comprehensive procedures for emergency situations and have a strategy and plans in place for the safe and prompt restoration of electricity supply. *TSOs* shall also ensure that their personnel and any of their *Users* involved in implementing the emergency procedures are fully aware of and trained and tested in their responsibilities.

TSOs shall provide copies of their emergency plans and procedures to neighbouring *TSOs*, *EAPP CC* and to relevant *Users* within their *National Systems*. These plans and procedures shall be coordinated with other *TSOs,* the *EAPP CC* and *External Systems*.

The emergency plans and procedures agreed between *TSOs*, *EAPP CC* and relevant *Users shall* include, but not be limited, to the following:

(a) The procedures for the dissemination of the system state warnings set out in Section 10.1 in Chapter 10 (Operations Code No. 3 - Emergency Operations – System Warnings) to neighbouring *TSOs*, *EAPP CC* and relevant *Users* and the actions to be taken on receipt of a warning;

(b) The requirement to establish and maintain reliable communications between all interested parties and the communications protocols to be used;

(c) A list of personnel appropriately authorised to take action in emergencies together with their contact details;

(d) Any requirement under national legislation to inform government and other public authorities of the existence of an emergency condition on the *EAPP Interconnected Transmission System* and the possible effects of the situation on population and infrastructure;

(e) The requirement to ensure rapid information exchange between *TSOs* about system conditions particularly close to their common borders. This information should include the topology of the system and its weak points and the potential risks of tripping;

(f) The possible need to arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot beused;

(g) A contingency plan to continue safe and reliable operations in the event of total loss of a *TSO's* Control Centre or communications facilities;

(h) The need to ensure that sufficient resources of trained, tested and authorised personnel are available in control rooms and for operation under all conditions;

(i) The need to modify cross-border transfers to alleviate overloading;

(j) The application of load shedding in some parts of the *EAPP Interconnected Transmission System* in order to limit the risk of cascade tripping;

(k) The regular training of all personnel in operation under emergency conditions.

TSOs shall make every effort to remain connected to the *EAPP Interconnected Transmission System* under emergency conditions. If a *TSO* however considers that its *National System* is endangered if it remains connected, it may implement any remedial action necessary to protect its own *National System*.

10.1.6.1 Review of Emergency Procedures

TSOs shall review and update their emergency plans and procedures every year or whenever significant changes are made to the *EAPP Interconnected Transmission System*. They shall also take account of deficiencies noted when carrying out simulations and exercises of the emergency plan and procedures and any recommendations arising from reports prepared under OC 4, or Chapter 11 (Operations Code No. 4 – Incident Reporting).

The *EAPP Sub-Committee on Operations* is responsible for the review of the emergency procedures annually to ensure that the emergency plans and procedures comply with OC 3, or Chapter 10 (Operations Code No. 3 – Emergency Operations).

10.1.7 System Restoration and Black Start

The procedure necessary for a recovery from a *Total Shutdown* or *Partial Shutdown* is known as a *Black Start* Procedure. The main objective of a *Black Start* is the restoration of the *EAPP Interconnected Transmission System* as an integrated whole in the shortest possible time using the most effective means following a *Total Shutdown* or *Partial Shutdown*.

The complexities and indeterminate nature of recovery from a *Total Shutdown* or *Partial Shutdown* require that any *Black Start* Procedure is sufficiently flexible in order to accommodate the full range of *Generating Unit* and *EAPP Interconnected Transmission System* characteristics and operational possibilities. This precludes the setting out of concise chronological sequences. The overall strategy may include the overlapping phases of establishment of isolated groups of *Generating Units* together with complementary local demand. These groups are termed *Power Islands*. The step-by-step integration of these *Power Islands* into larger sub-systems will eventually result in the re-establishment of the *EAPP Interconnected Transmission System*.

10.1.7.1 Responsibilities

TSOs are responsible for the preparation of the strategy and plan for system restoration and *Black Start* as part of the procedures set out in Section 10.1.6 (Operations Code No. 3 – Emergency Operations – Emergency Procedures).

When a *Total Shutdown* or *Partial Shutdown* exists on its *National System*, the *TSOs* shall notify the *TSOs* of *Neighbouring Systems* and the *EAPP CC* and shall agree the initial steps in the restoration process.

Each *TSO* is primarily responsible for re-starting its respective *National System* after a *Total* or *Partial Shutdown* that disconnects its system from the *EAPP Interconnected Transmission System*.

Each *TSO* shall be responsible for ensuring *Generating Units* with *Black Start Capability* are available within its *National System*. TSOs shall contract for *Black Start* capability in accordance with the Chapter 16 (ISBC Chapter No. 3 - Ancillary Services).

Appropriate tests and simulations shall be carried out on an annual basis to ensure that:

(a) *Black Start* Units are capable of starting up without any external power supply;

(b) the *National System* can be energised and loaded from the *Black Start* Unit(s), and

(c) The *National System* can be re-synchronised with the *EAPP Interconnected Transmission System*.

Black Start Tests may involve synchronisation of generation to the *EAPP Interconnected Transmission System* or connection of demand remote from the *Black Start* Unit.

10.1.7.2 Procedure

In the event that the systems of neighbouring *TSO*s remain de-energised after a *Total Shutdown* of the *EAPP Interconnected Transmission System*, *TSOs* shall determine, by means of tests or simulations, the amount of system and load that could be energised from their *National System*.

Whenever possible the *TSOs* affected by a *Total Shutdown* shall coordinate the restoration process. If they consider it necessary to re-configure the *EAPP Interconnected Transmission System* or disconnect some cross-border connections, they shall request the *EAPP CC* to coordinate the operation with all other *TSOs* that may be affected by the action.

Each*TSO* shall recover its *National System* and obtain the balance between generation and demand in coordination with its *Users*, handling the synchronisation operations of their systems until complete integration with the *EAPP Interconnected Transmission System* is achieved. The *EAPP CC* shall be responsible for the overall supervision of the restoration process of the *EAPP Interconnected Transmission System*.

During the initial stages of restoration normal operational security standards may not be appropriate or possible and the *EAPP Interconnected Transmission System* or a *National System* may be operated outside normal voltage and frequency limits provided that it does not result in damage to *Plant* and or *Apparatus*, or a safety hazard to persons.

10.1.7.3 Power Islands

EAPP CC shall coordinate the formation of *Power Islands* where such *Power Islands* include the parts of more than one *National System*. The *EAPP CC* shall designate one *TSO* to act as the *Control Area Operator* for such a *Power Island* until such time as re-synchronisation with the *EAPP Interconnected Transmission System* has occurred.

The designated *TSO* of a *Power Island* shall ensure that the *Power Island* is managed in a secure and safe manner. Where possible a *Power Island* should be operated in accordance with the following frequency and voltage criteria:

(a) The frequency in the Island shall be nominally 50 Hz and shall be controlled within the limits 49.5 – 50.5 Hz;

(b) The voltage on the Transmission System in the Island shall normally remain within -/+ 10% of nominal. Voltages of +20% and –15% should not prevail for more than 15 minutes.

Close coordination between *TSOs* and *Users* is required to achieve and maintain these frequency and voltage levels.

10.1.7.4 Completion of Black Start and System Restoration

When the *Black Start* and system restoration are complete the *EAPP CC* shall formally notify *TSOs* that the *Black Start* is complete and normal operation has been resumed.

10.1.8 Reporting of Emergency Conditions

The reporting of significant incidents during emergency conditions and or *Black Start* shall be in accordance with Chapter 11 (Operations Code No. 4 – Incident Reporting), or OC 4, which also contains provision for the Joint Investigation of incidents.

10.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

10.2.1 Introduction

This section specifies guidelines for developing criteria and procedures that are specific to the *SO* for emergency operations of the *Kenya National Transmission System (KNTS).*

10.2.2 Emergency and Contingency Planning

The following emergency and *Contingency* planning actions are specific for the *SO* and are elaborated where needed:

(a) The *SO* shall develop and maintain *Contingency* plans to manage system contingencies and emergencies that are relevant to the performance of the *KNTS*. Such *Contingency* plans shall be developed in consultation with all *Users* shall be consistent with internationally acceptable utility practices, and shall include but not be limited to:

   (i) Under-frequency load shedding

   (ii) Meeting Kenya's disaster management requirements, if any, including the necessary minimum load requirements

   (iii) Forced *Outage*s at all points of interface, and

   (iv) Supply restoration

(b) Emergency plans shall allow for quick and orderly recovery from a partial or complete system collapse, with least cost solution and minimum impact on *Customer*s.

(c) Emergency plans shall comply with *EAPP* agreements and guidelines.

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

(e) The *SO*shall specify minimum emergency requirements for *Designated Control Centre*s, *Generating Plant* local control centres and substations to ensure continuous operation of their control, recording, annunciator and communication facilities.

(f) It shall be ensured that other *Users* comply with the *SO*'s reasonable requirements for *Contingency* and emergency plans.

(g) The *SO*shall set the requirements for automatic and manual load shedding. *Users* shall make available loads and schemes to comply with these requirements. When the *SCADA* system displays a sudden loss of generation accompanied by a drastic drop in system frequency without the operation of under frequency scheme, the *SOshall* monitor the system for a voltage collapse. If a voltage collapse is imminent, controlled load shedding is initiated according to *SO*documented procedures.

(h) If a sudden loss of a large generation plant occurs on the system followed by an operation of under frequency scheme, the *SO*shall initiate action according to documented procedures.

(i) The *SO*shall be responsible for determining all operational limits on the *KNTS*, updating these periodically and making these available to the *Users*.

(j) The *SO*shall conduct load flow studies regularly as indicated in Section 10.1.5 (Responsibilities of TSOs – Security Analysis) to determine the effect that various component failures would have on the reliability of the system. At the request of the *SO*, *TNSP*s shall perform related load flow studies on their part of the network and make the results available to the *SO*.

(k) Studies shall be made on a coordinated basis to:

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

  (ii) determine operating limitations for normal operation when all transmission components are in service; and

  (iii) determine operating limitations of transmission facilities under abnormal or emergency conditions. In determining ratings of transmission facilities, consideration shall be given to:

    1. Thermal and stability limits;
    2. Short and long time loading limits;
    3. Voltage limits.

(l) 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 power system which may affect the Emergency Transfer Capability.

(m) Studies shall be made to develop operating voltage or reactive schedules for both normal and *Outage* conditions.

(n) Adequate coordination with the *Neighbouring Systems* to use uniform line identifications and ratings when referring to transmission facilities of a transmission system network shall foster consistency when referring to facilities and reduce the likelihood of misunderstandings.

(o) The scheduling of *Outage*s of transmission facilities which may affect *Neighbouring Systems* shall be co-ordinated with the appropriate authorities.

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

11 OPERATIONS CODE NO. 4 – INCIDENT REPORTING

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall apply.

11.1 EAPP IC REQUIREMENTS

11.1.1 Introduction

Operations Code No. 4 (OC 4) sets out the requirements for reporting significant incidents that have caused, or could have caused, damage to persons, system equipment, or operation of the *EAPP Interconnected Transmission System* outside the standards set out in Operations Code No. 2 (OC 2) of Chapter 9.

OC 4 also describes the procedure for the joint investigation of significant incidents and for the technical audit of *TSO's* procedures and *Plant* and or *Apparatus* connected to, or forming part of, the *EAPP Interconnected Transmission System*.

11.1.2 Objective

The objectives of OC 4 are:

(a) To specify the roles and responsibilities of *TSOs* and *EAPP CC* with regard to significant incident reporting;

(b) To provide for the joint investigation by *TSOs*, *EAPP Steering Committee* and the *Independent Regulatory Board* of any significant incident that has had, or could have had, a widespread impact on any part of the *EAPP Interconnected Transmission System,* and

(c) To make provision for the technical audit of a *TSO*'s procedures and *Plant* and/or *Apparatus* connected to, or forming part of, the *EAPP Interconnected Transmission System*.

11.1.3 Reporting Requirements

Where a *TSO* becomes aware of a significant incident on its *National System* which, in the*TSO*'s view, compromised, or may have compromised the integrity or secure operation of the *EAPP Interconnected Transmission System,* the *TSO* shall notify the *EAPP CC* and other affected *TSOs* of such significant incident as a matter of urgency.

The *EAPP Steering Committee* and the *Independent Regulatory Board* may require the provision of a report on a significant incident which in their view has compromised the secure operation of the *EAPP Interconnected Transmission System*.

Without limiting the requirements of OC 4, *TSO*'s shall report any of the following incidents that have or could have adversely affected the security of the *EAPP Interconnected Transmission System* or the safety of persons or system equipment:

(a) Manual or automatic tripping under emergency conditions of system circuits and *Plant* associated with the *EAPP Interconnected Transmission System*;

(b) An uncontrolled loss of generation of greater than 30 MW;

(c) A loss of demand greater than 20 MW for more than 15 minutes from a single incident;

(d) Load shedding of more than 20 MW implemented for local reasons;

(e) The occurrence of a system separation or islanding;

(f) Deviation of voltage and or frequency outside the limits of the CC;
(g) System instability;
(h) Implementation of *Black Start* procedures;
(i) Sabotage, vandalism, terrorism and cyber-attacks affecting the security of the *EAPP Interconnected Transmission System*;
(j) Major safety incident.

The Report shall provide a detailed description of the incidents that occurred as well as the actions taken for the re-establishment of normal conditions on the *EAPP Interconnected Transmission System*.

11.1.4 Incident Reports

11.1.4.1 Initial Report

The Initial Report shall be prepared immediately and shall be submitted to the *EAPP CC* within four (4) hours of the occurrence of the significant incident. The Initial Report shall include, in the format of Section 11.1.7 (Sample Report) of this chapter, without limitation, the following information:

(a) A description of the significant incident detailing the sequence of events;
(b) The time and date of the significant incident;
(c) The location(s) of the significant incident;
(d) *Plant* and or *Apparatus* directly involved and not merely affected by the significant incident;
(e) A preliminary diagnosis of probable cause(s) of the significant incident;
(f) The consequences on the *EAPP Interconnected Transmission System* (lossof load, unavailability of generating and transmission facilities, protection operations);
(g) Immediate actions performed to restore the system to a normal operative state; and
(h) Any other information available in relation to the significant incident.

Those incidents that were not identified until sometime after they occurred shall be reported to the *EAPP CC* within four (4) hours of being recognised.

11.1.4.2 Interim Report

Depending on the severity or complexity of the significant incident, an Interim Report may be issued. This report shall be submitted to the *EAPP CC* within five (5) business days of the occurrence of the incident. It shall contain further analysis of the incident together with provisional recommendations for action to be taken, on an urgent basis, regarding procedures or facilities of the *EAPP Interconnected Transmission System*. The purpose of the Interim Report is to alert the *EAPP CC* and other *TSOs* of the possible need to take immediate action.

11.1.4.3 Final Report

A Final Report shall be presented to the *EAPP CC* within thirty (30) business days of the occurrence of the significant incident. As a minimum the Final Report shall contain a description of the incident, the identification of its root cause, the conclusions reached and recommendations for corrective actions, if applicable, to prevent recurrence of this type of incident.

When a *TSO* requires more than thirty (30) business days to submit a Final Report, it may request additional time and agree a new timescale to carry out the relevant investigations.

11.1.4.4 Evaluation and Approval of Reports

All reports shall be circulated by the *EAPP CC* to the *EAPP Steering Committee*, to the *Independent Regulatory Board and to* other relevant *TSOs*.

The Final Report is subject to the approval of the *EAPP Steering Committee* and of the *Independent Regulatory Board*. If either body fails to approve the Final Report, the incident shall be subject to a Joint Investigation in accordance with Section 11.1.4 in this chapter.

11.1.4.5 Actions Arising from Incidents

When the Final Report of a significant incident concludes that action is required to implement the recommendations of the Report, the *TSOs* concerned shall draw up an implementation timetable. The actions required as a result of incidents are likely to involve the following:

(a) Modification of operating procedures;

(b) Modification of equipment (e.g. control systems or *Remedial Action Schemes*);

(c) Identification of any lessons learned;

(d) Non-compliance with operational or technical procedures or any provision of the *EAPP*/*EAC* Interconnection Code or National Grid Codes or equivalent documents.

The *EAPP Sub-Committees on Planning and Operations* shall track and review the status of all recommendations from Final Reports at least twice a year to ensure they have been implemented in due time. If any recommendation has not been implemented within two (2)years, or if the tracking and review process indicates at any time that the recommendation(s) are not being pursued with due diligence, the matter shall be bought formally to the attention of the *EAPP Steering Committee* and the *Independent Regulatory Board* for further action.

11.1.5 Joint Investigation

Where an incident has occurred and a Final Report submitted under Section 11.1.3 in this chapter, the affected*TSO*s or the *EAPP CC* may request in writing that a Joint Investigation be carried out. A Joint Investigation shall also be carried out in accordance with the provisions of Section 11.1.3 where approval of the Final Report by the *EAPP Steering Committee* and or the *Independent Regulatory Board* has been withheld.

The composition of the Joint Investigation Committee shall be appropriate for the incident to be investigated and agreed by all parties involved. If an agreement cannot be reached on the composition of the Committee, the *EAPP Steering Committee* and the *Independent Regulatory Board* shall decide.

The terms of reference and all matters relating to the Joint Investigation shall be agreed by the parties in good faith and in a timely manner. The investigation shall begin within fifteen (15) business days from the request for a Joint Investigation.

11.1.6 Technical Audit

Based on an analysis made by the *EAPP Sub-Committees on Planning and Operations* or the *Independent Regulatory Board* of all Final Reports, it may be decided to carry out a technical audit of the *EAPP Interconnected Transmission System* facilities or of the operational procedures used by *TSOs* and the *EAPP CC*.

These technical audits shall be carried out by experts nominated by the *EAPP Sub-Committees on Planning and Operations* or *Independent Regulatory Board* as the case may be. *TSOs* shall allow access for the inspection of their facilities, provide the required information, and accept and comply with the recommendations of the technical audit.

11.1.7 Sample Report

[Suggested Format of Reports]

SIGNIFICANT INCIDENT REPORT NO …………………………………………………..

REPORTING TSO …………………………………………………………….……………

TYPE OF REPORT (CIRCLE) INITIAL/INTERIM/FINAL

TIME OF INCIDENT ……………………………………………………………………

DATE OF INCIDENT ……………………………………………………………………

LOCATION OF INCIDENT ……………………………………………………………….

………………………………………………………………………………………………

………………………………………………………………………………………………

PLANT OR APPARATUS DIRECTLY INVOLVED ………………………………………

…..……………………..………………………………………………………………………

…..……………………..………………………………………………………………………

..………………………………………………………………………………………………

ESTIMATED TIME AND DATE OF RETURN TO SERVICE……...………………………

………………………………………………………………………………………………

DESCRIPTION OF SIGNIFICANT INCIDENT …………………………………………...

…………………………………………………………………………………………...........

…………………………………………………………………………………………...........

…………………………………………………………………………………………...........

…………………………………………………………………………………………...........

…………………………………………………………………………………………...........

…………………………………………………………………………………………...........

OTHER RELEVANT INFORMATION (Weather conditions, change in output of Generating Units etc.)

……

……

……

CAUSE OF SIGNIFICANT INCIDENT where known at time of Report

……

……

……

……

……

……

RECOMMENDATIONS FOLLOWING INVESTIGATIONS

……

………………………………………………………………………………………………………..

……

……

11.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

11.2.1 Reporting of Operations Incidents

This section specifies guidelines for developing procedures for incident reporting that are specific to the *KNTGC.*

A major incident is defined as an incident where:

(i) Load was interrupted for more than allowable time as determined by the *SO*; and
(ii) Severe damage to plant or system equipment has occurred.
(iii) There is personal injury or loss of life.

In case of a major incident, a *User* shall have the right to request an independent audit of the report, at their own cost, if they are not satisfied with it. If these audit findings disagree with the report, the *User* may follow the dispute resolution mechanism. If the audit agrees with the report, the report recommendations shall prevail and be implemented within the time frames specified.

An incident is reported to the *SO* by *TNSPs* or the *DCCs* when a major disturbance occurs on the *KNTS* resulting in casualties, loss of supplies or damage to equipment. An incident shall be reported with the information on the nature of incident, its location, people/*Customer*s/installations affected, and corrective actions taken as soon as possible. Procedure for handling incident reporting shall be followed as per documented *SO*procedures. Following are some guidelines regarding incident reporting, investigation, and analysis:

(a) *Generation Licensee*s shall report loss of output and tripping of units and change of status of *AGC* and governing to the *SO*within fifteen (15) minutes of the event occurring.

(b) In the event of a multiple unit tripping, the relevant *Generation Licensee* shall submit a written report to the *SO*within one (1) month identifying the root causes of the incident and the corrective actions taken.

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

(d) Incidents shall be reported to the *Authority* as defined in the licence conditions.

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

(f) The *SO* may also issue an incident report to a *User*, where the *User* does not comply with necessary requirements. The *User* shall provide the *SO* with reasons for the incident and, where appropriate, indicate the measures that will be taken to address the problem.

(g) Incidents involving sabotage or suspected sabotage, as well as threats of sabotage on the power system shall be reported to the *SO*.

(h) Any incident that materially affected the quality of the service to a *User shall* be formally investigated. These include interruptions of supply, disconnections, under or over voltage incidents, quality of supply contraventions, etc. A preliminary incident report shall be available after three (3) business days and a final report within three (3) months. *The SO* shall initiate such an investigation, arrange for the writing of the report and involve all affected *Users*. All these *Users* shall make all relevant required information available to the *SO*. The confidentiality status of information involved shall be maintained.

High risk incidents include ones causing:

(a) significant disruption of supply to *Customer*s;
(b) substantial damage to equipment and switchgears;
(c) fires; and
(d) adverse environmental consequences (e.g. bushfires, environmental pollution, etc.).

As per this document, the following actions shall be necessary for incident reporting:

(a) Copies of events, sequence of events and post mortem review (PMR) print-outs from the *SCADA* system (includes loading and generation situation before the disturbance, and historical performance of the failed equipment).

(b) Details regarding the fault containing chronological description of the incident's occurrence, operations during the incident and the cause of the incident.

(c) Any shortcomings experienced such as: Protection malfunctions; Malfunction of *Electrical Plant* equipment; Malfunction of telecommunications and *SCADA*; Transport problems; Manpower problems.

(d) Any of the following actions taken after occurrence of the incident: Emergency actions taken; Strategies taken to operate the system under fault condition; Operating procedures used during the disturbance; instructions issued, timings for execution; Restoration actions initiated.

(e) Any conclusions/recommendations that include: Weaknesses found in the disturbance handling, equipment mal-operations performance; System response to the disturbance; Any mal-operations; Evaluation of all aspects of operation; Any modifications of disturbance handling procedures and why.

(f) Any remedial actions taken to restore supplies and equipment.

(g) Submission of completed reports to the *SO and Authority*.

Despite the urgency of the situation, careful, prompt, and complete logging of all operations and operational messages shall be ensured by all *Users* to facilitate subsequent investigation into the incident and the efficiency of the restoration process.

12 OPERATIONS CODE NO. 5 – DEMAND CONTROL

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

12.1 EAPP IC REQUIREMENTS

12.1.1 Introduction

Operations Code No. 5 (OC 5) sets out the provisions to be made by a *TSO,* in cooperation with the *EAPP CC*, to permit reductions in demand in the event of insufficient generation capacity being available to meet demand or in the event of breakdown or thermal overloading of any part of the *EAPP Interconnected Transmission System* leading to the possibility of unacceptable frequency or voltage conditions. Without limitation, the provisions of OC 5 may be used in the event of both a steady-state shortfall of generation and a transient shortfall following an instantaneous loss of generation.

TSOs shall, after taking all other remedial actions, disconnect *Customer* demand rather than risk an uncontrolled failure of *Plant* and or *Apparatus* or cascading *Outages* of the *EAPP Interconnected Transmission System*.

12.1.2 Objective

The objective of OC 5 is to require *TSOs* to have procedures in place to enable a reduction in demand on the *EAPP Interconnected Transmission System* in order to avoid a breakdown or overloading of the system or in the event of generation shortage.

12.1.3 Methods of Demand Control

To preserve the security of the *EAPP Interconnected Transmission System,* OC 5 deals with the following types of demand control:

(a) *Automatic Load Shedding* activated by low frequency and low voltage relays;

(b) Emergency manual load shedding, and

(c) Planned manual load shedding including voltage reduction and *Rota Load Disconnection;*

The type of demand control utilised by the *TSO* in any particular circumstances will depend upon the amount of time between the *TSO* becoming aware of the need for implementing demand control and the time at which it needs to be implemented. In the event of a sudden and unexpected loss of generation on the *EAPP Interconnected Transmission System*, the requisite demand control will normally be achieved by means of *Automatic Load Shedding* but, occasionally, emergency manual disconnection may additionally be required. In all cases when demand control is necessary, the *TSO* shall use demand disconnection as the last option.

12.1.4 Risk of Demand Reduction

The *TSO* and or the *EAPP CC* shall issue a notification of a risk of demand control whenever it is anticipated that there may be insufficient generating capacity available to meet demand or that there is a risk of serious disturbance to the *EAPP Interconnected Transmission System*.

Any such notification issued shall be provided as soon as reasonably possible after the *TSO* or the *EAPP CC* has grounds to believe that there is a risk of demand reduction. The notice shall include an estimate of:

(a) The required level of demand control in MW;
(b) The expected start time and duration of demand control.

Under the terms of Operations Code No. 3 – Emergency Operations of Chapter 10, *TSOs* and or *EAPP CC* are responsible for the issue of ALERT and EMERGENCY warnings. The existence of a risk of demand reduction shall normally be included within one of these warnings.

12.1.5 Automatic Load Shedding Schemes

Under generation shortfall conditions, the frequency graded *Automatic Load Shedding Scheme* is used to prevent frequency collapse on the *EAPP Interconnected Transmission System* and to restore the balance between generation output and demand.

Each *TSO* shall establish plans for *Automatic Load Shedding* for under-frequency and under-voltage conditions. The overall *Automatic Load Shedding Scheme* for the *EAPP Interconnected Transmission System* shall be coordinated by the *EAPP CC* in order to prevent excessive transfers across the *EAPP Interconnected Transmission System* and possible instability.

A *TSO* shall implement load shedding in steps established to minimise the risk of further uncontrolled separation, loss of generation, or system shutdown.

TSOs shall coordinate *Automatic Load Shedding* in their *National Systems* with under-frequency isolation of *Generating Units*, tripping of shunt capacitors, and other automatic actions that will occur under abnormal frequency, voltage, or power flow conditions.

12.1.6 Procedure

The following procedures are to be followed by a *TSO* in the implementation of the *Automatic Load Shedding Scheme* on its *National System*:

(a) Each *TSO* shall make available up to 60% of its annual peak demand for the *Automatic Load Shedding Scheme*;
(b) Schemes shall be based on system dynamic performance where the greatest probable imbalance between demand and generation is simulated;
(c) Schemes should be analysed to ensure that no unacceptable over-frequency, over-voltage or transmission overload will occur;
(d) The demand on the *EAPP Interconnected Transmission System* subject to an *Automatic Load Shedding Scheme* will be split by the *TSO* into discrete blocks. The number, location, size and the associated low frequency or low voltage settings of these blocks will be as determined by the *TSO* in consultation with the *EAPP CC* and shall not unduly discriminate against or unduly prefer any one group of *Users*. The *TSO* and *EAPP CC* shall also take into account constraints on the *EAPP Interconnected Transmission System* when determining the size and location of demand reduction by *Automatic Load Shedding*;
(e) If the *EAPP Interconnected Transmission System* is still in a critical condition following frequency or voltage recovery after the activation of the *Automatic Load Shedding Scheme*, a *TSO* may implement manual disconnection of additional demand to permit restoration of the previously disconnected demand;
(f) Demand disconnected by the *Automatic Load Shedding Scheme* shall only be restored on the instruction of the *TSO* with the agreement of the *EAPP CC* unless there are particular local circumstances;

(g) The settings of under-frequency and under-voltage relays shall be coordinated with the emergency plans and procedures required by Operations Code No. 3 – Emergency Operations.

(h) *TSOs* and *EAPP CC* shall review annually the settings of under-frequency and under-voltage relays and the levels of demand to be disconnected.

12.1.7 Planning and Emergency Manual Load Shedding

Planned manual disconnection is the procedure adopted when the *TSO* has reasonable notice that a generation shortfall and or *EAPP Interconnected Transmission System* problems may require demand control. *TSOs* may also initiate voltage reduction in lieu of demand disconnection as necessary.

Each *TSO* shall be responsible for maintaining *Rota Load Disconnection* plans for use where a shortage of generation is anticipated over a prolonged period. The *Rota Load Disconnection* plans shall provide for the disconnection and reconnection of defined blocks of demand on instruction from the *TSO*. In this way the *TSO* can instruct the necessary level of disconnection (and reconnection) required by the circumstances at the time. The *Rota Load Disconnection* plans of each *TSO* shall be coordinated by the *EAPP CC* to ensure that where the generation shortage is common to a number of countries of *EAPP* the resulting demand control is applied equitably.

Emergency manual disconnection is utilised by the *TSO* when a loss of generation or a mismatch of generation output and demand is such that there is an operational requirement to disconnect demand at short notice or in real time to maintain a margin between generation output and demand and in certain circumstances to deal with operating problems such as unacceptable voltage levels and thermal overloads. *TSOs* shall maintain emergency manual disconnection plans and procedures, coordinated with *EAPP CC*, to implement manual load shedding in a timeframe adequate for responding to an emergency.

TSOs shall ensure that, as far as practicable, demand reductions are deployed equitably. In the case of protracted generation shortage or transmission system overloading, large imbalances of generation and demand may cause excessive power transfers across the *EAPP Interconnected Transmission System*. If such transfers threaten the stability of the *EAPP Interconnected Transmission System* or could damage generating and transmission facilities, the pattern of demand reduction shall be adjusted to secure the *EAPP Interconnected Transmission System*, notwithstanding the inequalities of disconnection that may arise from such adjustments.

12.1.8 Demand Restoration

When *EAPP Interconnected Transmission System* conditions have returned to normal, *TSOs* may, with the consent of *EAPP* CC, initiate demand restoration. Demand restoration will normally be instructed in stages as equitably as practicable. Two or more stages of demand restoration may be carried out simultaneously where appropriate. Procedures for demand restoration after a *Total* or *Partial Shutdown* shall be in accordance with OC 3, Section 10.1.7 of Chapter 10 (Emergency Operations – System Restoration and Black Start).

12.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

12.2.1 Introduction

This section specifies guidelines for developing criteria and procedures to be applied by the *SO* for demand control of the *Kenya National Transmission System (KNTS).* Provisions of this section are to enable the SO to implement demand reduction or demand addition in a manner that ensures the continued balance between supply and demand under normal or emergency conditions.

The objective of demand control is to achieve reduction in demand in the transmission grid in order to:

(a) manage system security during low operating reserve; and
(b) prevent system overload or voltage collapse.

Demand control shall, in general, apply to *Generation Licensee*s, *TNSP*s, Distribution *Licensees*, and End-users.

12.2.2 Planned Demand Control

If a supply-demand mismatch is foreseen, the *SO* will alert *Users* drawing power from the *SO* grid in terms of the times and load quantum to be curtailed. The *SO* shall consult the *Users* in producing a load shedding programme that shall be followed when there is planned load demand control. During emergency conditions the *SO* may curtail load in a manner that does not strictly follow the agreed load shedding programme. Planned demand control is detailed under Section 12.1.6 in this chapter, Emergency Demand Control.

Emergency automatic demand control occurs when there is a sudden loss of generation substantially in excess of spare plant capacity. The *SO* in consultation with *KNTS Users* shall prepare the plan for automatic load shedding during the low frequency conditions. For details on automatic load shedding, refer to Section 12.1.5 in this chapter. During periods of low frequency conditions, *Generating Plants* shall assist through the following:

(a) Make every effort to assist the system frequency to rise to 50 Hz, by increasing generation whenever possible;
(b) Not disconnecting manually from the transmission system unless there is definite evidence that a complete failure of generation would otherwise result.

The *SO shall* enforce demand control in such a manner that does not unduly discriminate against, or unduly prefer anyone.

If the *SO* anticipates any generation shortfall based on the difference between anticipated maximum demand and available generation capacity, the *SO* shall work with all relevant personnel following the operational guidelines below:

(a) The *SO shall* work out the anticipated generation shortfall by working out the difference between anticipated maximum demand and available generation capacity.
(b) The *SO shall* work out each region's required load rationing during the shortfall period, and inform *DCCs* of their required load rationing targets.
(c) The *DCCs* shall liaise with the *SO* to determine the *End-users* and feeders to be affected.
(d) The *DCC's* shall inform the *End-users* of their required load reduction magnitudes and the time period.

(e) The *DCCs* shall be at the relevant *End-users* premises before start of reduction period to ensure and confirm compliance by such *Users*.

(f) The *DCC*s shall inform the *SO* of *End-users'* compliance with load reductions.

(g) The *SO* shall evaluate system status and determine if the *End-users'* load reduction is adequate. If reduction is inadequate, the *SO* shall instruct *DCC*s to carry out additional load shedding.

(h) *RCC*s shall carry out load shedding as instructed by the *SO*. *DCC*s shall instruct operators to carry out load shedding in places where there are no *SCADA* commands.

(i) *RCC*s shall notify the *SO* of completion of carrying out load shedding.

(j) The *SO* shall evaluate system status. If load shedding is inadequate, the *SO shall* instruct *RCC*s to carry out further load shedding.

(k) If load shedding is adequate, the *SO shall* wait for the recovery of the system while monitoring system status parameters (voltage and frequency) on the *SCADA*.

(l) The *SO shall* determine if system has recovered from generation shortfall.

(m) If the system has not recovered from generation shortfall, the *SO shall* wait for the recovery of the system while monitoring system status parameters (voltage and frequency) on the *SCADA*.

(n) If system has recovered from generation shortfall, the *SO shall* instruct *RCC*s to restore *Customer*s/ inform *Customer*s to pick load.

(o) *DCC*s shall restore *Customer*s where there is remote control. *RCC*s shall instruct operators to restore *Customer*s where there is no remote control. *RCC*s shall also inform *End-users* who had reduced load to resume normal operation. Restoration of such *Users* shall be done systematically as directed by the *SO*.

(p) The *SO shall* compile a detailed Load Shedding report.

13 OPERATIONS CODE NO. 6 – SYSTEM TESTS

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

13.1 EAPP IC REQUIREMENTS

13.1.1 Introduction

Operations Code No. 6 (OC6) sets out the arrangements and procedures across the *EAPP Interconnected Transmission System* for *System Tests* or operational tests including *Black Start* tests and *Power Island* tests.

System Tests are those tests which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *EAPP Interconnected Transmission System*. In addition they include Commissioning and or acceptance tests on *Plant* and *Apparatus* to be carried out by a *User* and which may have a significant impact upon the *EAPP Interconnected Transmission System*.

System Tests or operational tests may involve single items of *Plant* and or *Apparatus* through to whole sections of the *EAPP Interconnected Transmission System* and may be proposed by *EAPP Sub-Committees on Planning or Operations* or a *TSO*.

To minimise disruption to the operation of the *EAPP Interconnected Transmission System* and or to other *TSO's National System*s, it is necessary that these tests be subjected to central coordination by the *EAPP CC* in cooperation with the relevant *TSO*.

OC 6 also describes the data exchange and communication requirements between *EAPP* and the *TSOs* to facilitate planning, implementation and reporting of *System Tests* or operational tests.

13.1.2 Objective

The objectives of OC 6 are to specify procedures for central co-ordination and control of a *System Test* or operational test required by a *TSO* or the *EAPP Sub-Committees on Planning or Operations*, where such test will or may:

(a) Affect the secure operation of the *EAPP Interconnected TransmissionSystem*;

(b) Have a significant effect on the operation of the *EAPP Interconnected Transmission System* or a *National System*;

(c) Affect the economic operation of the *EAPP Interconnected TransmissionSystem,* or

(d) Affect the quality or continuity of supply of electricity from the *EAPP Interconnected Transmission System*.

13.1.3 Procedure

13.1.3.1 General

Tests shall be planned to ensure all *Plant* and *Apparatus* remain within the applicable capability limits specified by the relevant *TSO* and carried out such that there is minimal impact on the *EAPP Interconnected Transmission System* or *TSOs' National Systems*. *System Tests* required by *TSOs* or *EAPP CC* shall include, but not be limited to the following:

(a) Tests involving the controlled application of frequency and or voltage variations aimed at gathering information on the behaviour of the *EAPP Interconnected Transmission System*;

(b) *Black Start* and system restoration tests;

(c) Testing of procedures and plans for system ALERT and EMERGENCY conditions;

(d) Testing or monitoring of power quality under various system conditions and generation configurations.

TSOs shall be responsible for obtaining the agreement of the relevant *User*(s) before tests proceed.

All *Outage* requests for Tests shall be progressed in accordance with the guidelines in Chapter 8 (Operations Code No. 1 – Operational Planning).

The category of Tests shall be agreed by the *EAPP Sub-Committees on Planning and Operations* and relevant *TSOs*.

Major Tests are those considered sufficiently complex by either *Party* to require a detailedTest programme to be submitted in accordance with the *Test Proposal* in Section 13.1.3 of this chapter.

OC 6 is not intended to deal with Tests categorised as minor or routine. Such tests do not require a detailed Test programme to be submitted.

Any *System Tests* on the *EAPP Interconnected Transmission System* which may affect an *External System* or tests on an *External System* which may affect the *EAPP Interconnected Transmission System* shall be carried out in accordance with the appropriate bilateral agreements.

13.1.3.2 Test Proposal

The level of demand on the *EAPP Interconnected Transmission System* varies substantially according to the time of day and time of year and, consequently, certain *System Tests* which may have a significant impact on the system can only be undertaken at certain times of the day and year. Other *System Tests*, for example, those involving substantial Mvar generation or full load rejection tests, may also be subject to timing constraints. It therefore follows that notice of *System Tests* should be given as far in advance of the date on which they are proposed to be carried out.

The *Test Proposer* shall provide a *Test Proposal* to *EAPP Sub-Committees on Planning or Operations* who shall be responsible for circulation to relevant *TSOs*.

Individual *TSOs* shall ensure that any of their *Users* who may be involved in or affected by the Test shall be provided with a copy of the *Test Proposal* and any updates thereof. Where practicable, the *Test Proposal* shall be submitted at least three (3) months prior to the proposed date of the Test. The *Test Proposer* shall ensure that sufficient detail is included in the *Test Proposal* to allow the affected parties to assess the impact of the Test on the *EAPP Interconnected Transmission System*, *TSOs' National Systems* and *Users' Systems*.

The *Test Proposer* shall be responsible for change control of the *Test Proposal* and shall issue a revised *Test Proposal* to *EAPP Sub-Committees on Planning or Operations*. *EAPP Sub-Committees on Planning or Operations* is responsible for liaising with any other affected *TSOs* who in turn shall notify any *Users* affected by the change.

EAPP Sub-Committees on Planning or Operations and the affected *TSOs* shall assess the implications and agree the category of the Test within a reasonable time. *TSOs* shall liaise with each affected *User* and seek their agreement to the *Test Proposal* and collate and coordinate their responses to the *EAPP Sub-Committees on Planning or Operations.*

Following receipt of the *Test Proposal* and evaluation of the Test's likely impact, including discussions of test requirements with the *Test Proposer* and other affected parties, the *EAPP Sub-Committees on Planning or Operations* taking into account the criteria set out in this chapter will decide if approval for the Test is granted.

If the *Test Proposal* is not acceptable to the *EAPP Sub-Committees on Planning or Operations*, an affected *TSO* or *User*, *EAPP Sub-Committees on Planning or Operations* shall refuse the *Test Proposal* and shall immediately notify the *Test Proposer*. The *Test Proposer* may choose to revise and re-submit the *Test Proposal* in accordance with this procedure or raise a *Dispute* under the terms of Section 3.11 of Chapter 3 (Dispute Resolution).

Any *Test Proposal* made by the *EAPP Sub-Committees on Planning or Operations* shall be subject to the prior approval of the *EAPP Steering Committee* and *Independent Regulatory Board* and shall otherwise be subject to the procedure set out above.

13.1.3.3 Detailed Test Programme

As soon as practicable after agreement to the *Test Proposal*, the *Test Proposer* shall provide an *Outage* request, in accordance with Section 8.1.5 of Chapter 8 (Operations Code No. 1 – Operational Planning – Outage Planning Process), to *EAPP CC* detailing the *Plant* and *Apparatus* involved.

The *Test Proposer* shall provide, within a reasonable time, a draft Test programme to a level of detail including, but not limited to, the content shown in Section 13.1.5 Sample Test Programme Report.

The *Test Proposer* shall be responsible for change control of the draft Test programme and shall issue within a reasonable time, a revised Test programme where appropriate to *EAPP CC*. *EAPP CC* is responsible for liaising with any other affected *TSOs* who in turn shall notify any *Users* affected by the change.

EAPP CC shall provide to each affected *TSO* a copy of the draft Test Programme and all updates thereof.

TSOs shall liaise with each affected *User* and seek their agreement to the Test Programme and collate and co-ordinate their responses to the *EAPP CC*.

EAPP CC and affected *TSOs* shall assess the implications of the Test programme on the safety, security, and reliability of the *EAPP Interconnected Transmission System*, individual *TSO National System*s and *User System*s.

When all issues raised have been addressed to the reasonable satisfaction of all parties and the draft Test programme agreed by all parties, the agreed Test programme shall be issued by *EAPP CC* to relevant *TSOs* at least fifteen (15) business days prior to the commencement date of the Test unless otherwise agreed.

In the event that there is a *Dispute* regarding the acceptability or otherwise of a Test programme or associated *Outage*, the Test shall not take place until the *Dispute* has been resolved.

13.1.3.4 Operational Process

EAPP CC shall be responsible for operational liaison and obtaining agreement from any affected *TSO* for the Test to proceed and shall co-ordinate the Test.

When Tests have commenced, any change in System, site or Test conditions that could affect or invalidate the Test or have an *Operational Effect* shall be communicated to other parties as soon as reasonably practicable. The Tests shall be suspended until all parties involved have assessed the implications of the change in system, site, or Test conditions.

In the event of a failure of communications between *EAPP CC* and relevant *TSOs* or the Test location during the Test, then the Test shall be suspended until satisfactory communications are restored and agreement is reached to continue with the Testprogramme.

13.1.3.5 Other Considerations

Tests shall normally only be carried out by *EAPP CC* or a *TSO* on *Plant* and *Apparatus* in operational service when the results of off-load Tests would not be sufficiently rigorous in the reasonable opinion of either *Party* to confirm the continued satisfactory performance of the *Plant* or *Apparatus* involved.

13.1.3.6 Operational Intertripping

No Tests shall take place that could result in operation of an operational intertripping scheme unless this is the stated purpose of the Test and agreement has been reached with all affected *Parties*.

Where testing of an operational intertripping scheme is not the stated purpose of testing then no Tests shall take place involving a circuit associated with an operational intertripping scheme unless the operational intertripping scheme is not required in service. The scheme must be deselected from service by a means agreed with all affected *Parties*.

13.1.4 Reporting of System Tests

Within three (3) months of the completion of the *System Test* or operational test, the *Test Proposer* shall prepare a Final Report on the Test. The Report shall be submitted to the *EAPP Steering Committee*, to the *Independent Regulatory Board* and to all *TSOs* affected by the Test.

The Final Report shall include a description of the *Plant* and or *Apparatus* tested and a description of the *System Test* carried out together with the results, conclusions and recommendations as they relate to the *EAPP* and *TSOs*.

13.1.5 Sample Test Programme Report

A detailed test programme for major testing shall:

(a) Have a unique identifier allocated by the *Test Proposer* and indicate the current version and issue number;
(b) Define the means of communication and location of all parties involved in theTest;
(c) Follow an agreed change control process for changes to the Test programme;
(d) Specify any associated documentation and diagrams including the numbering and nomenclature of Plant and Apparatus forming part of the Test programme and ensure these shall be accessible to all recipients of the Test programme;
(e) Identify the Plant and Apparatus subject to the Test and any other Plant and Apparatus that could be affected;
(f) Identify any *Operational Effects* or potential *Operational Effects* associated with the Test;
(g) Outline the initial conditions of the Plant and Apparatus subject to the test;
(h) Detail any temporary protection settings or protection equipment required for the purposes of the tests together with the settings applied;
(i) Provide a detailed tests schedule with location, action, any expected result and or *Operational Effect* identified for each item of the test's programme;
(j) For complex tests, breakpoints should be identified where the tests programme can be suspended and restarted without undue risk and with minimum disruption

13.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

This chapter discusses those tests which involve either a simulated or a controlled application of irregular, unusual or extreme conditions on the *KNTS*, not addressed in Section 13.1.

13.2.1 Commissioning and Compliance Tests

The *TNSP* or *Users* shall perform all Commissioning tests required in order to confirm that the plant and equipment meet all the requirements of the *KNTGC* that have to be met before going on-line. Such test must be certified by licensed engineers. The *SO* may request relevant tests (or results of such tests) to be demonstrated in accordance with the *KNTGC* before accepting such plant for operating. The party performing the test shall notify the *SO* and the *Authority* at least one week in advance of any such tests, so that they may witness the tests.

In addition to the safety of the system as described in Section 13.1.3.3 (Detailed Test Programme), it is necessary to ensure that the safety of personnel or members of the public are not threatened while conducting system tests.

It is important to ensure that the test programme specifies: switching sequence and proposed timings, list of staff involved in the test, and site safety responsible persons.

If a *Generating Plant* fails the system test, the *Generation Licensee* shall:

(a) Promptly notify the *SO* of that fact.
(b) Promptly advise the *SO* of the remedial steps it proposes to take to rectify the situation along the proposed timetable for implementing those steps.
(c) Diligently take remedial action to ensure that the relevant *Generating Plant* can comply if there is any compliance issue.
(d) Regularly report in writing to the *SO* on its progress in implementing the remedial action.
(e) Demonstrate to the reasonable satisfaction of the *SO* that the relevant *Generating Plant* passes the test and is compliant.

Procedures for Commissioning of a new *Generating Plant* shall be as follows:

(a) The *Generation Licensee* shall send to the *SO* details of the equipment to be commissioned including a diagram of the high voltage connection points prior to the Commissioning date.
(b) The *Generation Licensee shall* avail to the *SO* protective relay settings of the new *Generating Plant* prior to the Commissioning date.
(c) Before the Commissioning date, the *Generation Licensee shall* ensure that labels have been affixed to the equipment and its auxiliaries of the new *Generating Plant*.
(d) The *Generation Licensee* shall arrange for a training session for System Controllers/Operators of the *SO* responsible for operating the equipment prior to the Commissioning date.
(e) The *Generation Licensee shall* send a copy of the clearance certificate to the *SO* before the Commissioning date of the new *Generating Plant*.
(f) The Generation *Licensee shall* send to the *SO* a copy of the Commissioning programme, to connect the equipment to the system, seven (7) days before the Commissioning date.
(g) The Generation *Licensee shall* give notice of commissioning the equipment at least seven (7) days before the Commissioning date.
(h) The *SO shall* check and determine if there are any problems with the Commissioning taking place. If there are any problems, the *SO shall* discuss with the *GenerationLicensee and* agree on the appropriate date when Commissioning can take place.

(i) The *SO* shall log the Commissioning of the new equipment and capture *Planned Outages* in the Generation Dispatch schedule.
(j) The SO and TNSPshall organise for switching personnel to assist during the Commissioning.
(k) Before Commissioning commences, the *Generation Licensee shall* report to the *SO* the position of all circuit breakers (CBs), isolators, earth switches that are included in the New Equipment of the new *Generating Plant*.
(l) The *SO* shall co-ordinate all Commissioning.
(m) After successful Commissioning of the equipment, the *SO* shall declare the New Equipment to be under control of the *SO*.

Testing shall be carried out to confirm compliance of *Generating Plants* as per approved standards, and *Ancillary Services* provision. Details of testing for a *Generating Plant* shall typically include: Protection Integrity Tests - Trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV Breaker), shall be carried out and documented providing details of all trip test responses. Testing shall include:

(a) Excitation Response Test - With the *Generating Plant* in the open circuit mode, carry out the large signal performance testing as described in IEEE 421.2 of 1990; Determine time response, Ceiling voltage, voltage response. With the *Generating Plant* connected to the network and loaded, carry out the small signal performance tests according to IEEE 421.2.1990. Also carry out power system stabiliser tests and determine damping with and without Power System stabiliser. Document all responses.
(b) *Reactive Power* Capability Test - Reactive output for a *Generating Plant* shall be fully variable between its rated limits under *Automatic Voltage Regulation (AVR),* manual or other control. The duration of the test will be for a period of up to sixty (60) minutes during which period the system voltage at the grid entry point for the relevant *Generating Plant* shall be maintained by the *Generating Plant* at the voltage specified by adjustment of *Reactive Power* on the remaining *Generating Plant* units, if necessary, for a period of sixty (60) minutes. The *Generating Plant* shall demonstrate maintaining its reactive capability within ±5% of its rated capability.
(c) *Governor* Response Tests - Prove that the unit is capable of the minimum requirements required for governing frequency deviations.
(d) *Black Start* Test - *Black Start* Units shall perform appropriate tests and simulations on an annual basis to ensure that the *Black Start* facility is available. Such tests shall be witnessed and approved by the *SO*. A *Black Start* Station shall demonstrate that it can be synchronised to the system within thirty (30) minutes of the commencement of the *Black Start* procedure.
(e) Fault ride-through tests for VRPP and storage systems – tests may be omitted provided the Generation Licensee submits to the SO both certified type test reports and simulations using certified generating unit models demonstrating compliance with the requirements, and the SO has accepted this demonstration of compliance.
(f) Reconnection after disconnection test for VRPP and storage systems:
    (i).the active power output is at least 50% of nameplate capacity;
    (ii).The tests will be executed for the maximum reactive power output;
    (iii).The generating unit will be disconnected from the network;
    (iv).15 minutes after disconnection the generating unit will be reconnected to the network;
    (v).The active power output will gradually grow to at least 50% of nameplate capacity;
    (vi).The test is deemed successful if the following conditions are fulfilled:
    - The generating unit runs stable during the whole test;

- After reconnection the active power output increases by no more than 20% of the nameplate capacity per minute.

(g) House Load transfer test for synchronous units other than hydro:

- the generating unit' technical capability to trip to and stably operate on house load shall be demonstrated;
- the test shall be carried out at the maximum capacity and nominal reactive power of the generating unit before load shedding;
- the System Operator shall have the right to set additional conditions;
- the test shall be deemed successful if tripping to house load is successful, stable houseload operation has been demonstrated for two hours and re-synchronisation to the network has been performed successfully.

Other tests include:

(a) *Contingency*/Emergency plan Verification - Tests shall be periodically carried out to the greatest practical extent, as agreed by the parties, without causing undue risk or undue cost.

(b) Under-frequency load shedding (UFLS) Test - Test shall be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

14 ISBC CHAPTER NO. 1 - INTERCHANGE SCHEDULING

14.1 EAPP IC REQUIREMENTS

14.1.1 Introduction

One of the objectives of the *EAPP* is to facilitate trading in electricity among the *EAPP Member Countries*. In its initial stages such trading will consist of bilateral cross-border transactions between *Neighbouring Systems*. Once further infrastructure is developed more complex arrangements including multilateral transactions with or without transit through *Neighbouring Systems* will become possible and a Regional Power Pool Market will be established. Accordingly, the provisions of the ISBCs will be modified to reflect any *EAPP/EAC* new electricity market rules.

To operate the *EAPP Interconnected Transmission System* and to facilitate bilateral trade between *EAPP Member Countries* it is necessary to schedule in advance the *Active Power* and *Active Energy* to be transferred between *TSO National Systems* and to be imported from or exported to *External Systems.*

The term Interchange Scheduling in ISBC Chapter No. 1 (or ISBC 1) specifically refers to the intended delivery of *Active Power* and *Active Energy* from one *Control Area* to another *Control Area* within the *EAPP Interconnected Transmission System* or to be imported from or exported to *External Systems*.

ISBC 1 Interchange Scheduling deals with the following aspects of the scheduling process:

(a) Determination of the *Net Transmission Capability (NTC)* between *Neighbouring Control Areas* and or *External Systems* over the *Operational Planning* timescales;

(b) Publication of *NTC* values to enable *TSOs* and *Users* to evaluate possible *Active Power* and *Active Energy* interchanges;

(c) Allocation of *NTC* to *TSOs* and or *External Systems* in accordance with predetermined rules and the issue of Interchange Schedules.

14.1.2 Objectives

The objectives of the ISBC are:

(a) To enable *EAPP CC* and *TSOs* to establish and publish the *NTC* on the interconnections between *Control Areas* and or *External Systems* corresponding to the *Operational Planning* Phase, *Programming* Phase and *Control* Phase respectively as set out in Chapter 8 (Operations Code No. 1 OperationalPlanning)and

(b) To require *TSOs* to allocate the *NTC* to *Users* in accordance with certain rules.

14.1.3 Determination of Transmission Capability

NTC relates to the physical capability of the interconnection between *Control Areas*, and with *External Systems* to transfer *Active Power* and *Active Energy* and shall be determined by the *TSOs* concerned. The determination shall be based on the operational security standards set out in OC 2 and on such current technical and operational factors as are of significance to the *NTC*. *TSOs* are individually responsible for assessing these factors within their own *National Systems* and will determine in conjunction with *EAPP CC* the method of calculation of *NTC* between *Control Areas* and or *External Systems*. In determining *NTC TSOs* shall also take account of the following factors:

(a) Deviations of *Active Power* flows resulting from the operation or functioning of *Primary Response* to frequency changes;

(b) Emergency exchanges between *Control Areas* and or *External Systems* to cope with unexpected mismatch between generation and demand in realtime, and
(c) Inaccuracies in data collection and measurements.

14.1.4 Capacity Allocation

Certain *Users* may have acquired rights over the use of *NTC*. This may occur where the *User* concerned has provided generation or transmission facilities in accordance with a bilateral agreement. *TSOs* shall notify other relevant *TSOs* and the *EAPP CC* of the existence and extent of such agreements.

The *NTC* of the interconnection between *Control Areas* or with *External Systems* is firstly allocated to those *Users* with pre-emptive rights over the capability based on their bilateral agreements. After allocating *NTC* to *Users* who hold pre-emptive rights, *TSOs* may allocate the remaining capability of a particular interconnection in accordance with commercial agreements which are not the subject of this chapter.

14.1.5 Interchange Scheduling Process

The Interchange Scheduling process is concerned with:

(a) Providing an indication of feasible electricity trading scenarios;
(b) Determining *NTC* over various timescales;
(c) The coordination of *Outages* to minimise the loss of trading benefit to *Users* and to the *EAPP Interconnected Transmission System*; and
(d) The evaluation of potential actions by *TSOs* to mitigate constraints on the *EAPP Interconnected Transmission System* as set out in Operations Code No. 1 (OC 1).

As part of the *Operational Planning* process under OC 1, *TSOs* are required to make an assessment over various timescales of the *NTC* available on the interconnections between *Control Areas* and *External Systems*. This assessment is based on the Commissioning of new facilities and on the *Outages* required for planned maintenance of generating and transmission facilities. *TSOs* are required to publish details of the *NTC* on the *EAPP* Website.

Where a constraint in the *NTC* is identified when carrying out Interchange Scheduling in any of the *Operational Planning* timescales, the *TSOs* concerned shall seek to reallocate the Interchange Schedule to *Users* in the following priority order:

(a) Lowest priority will be energy exchanged as compensation for *Inadvertent Deviation*s;
(b) Energy transfers scheduled on a commercial basis by *TSOs* over and above the pre-emptive rights;
(c) Energy transfers scheduled as a consequence of pre-emptive rights, and
(d) Any agreements between *TSOs* for the provision of operating reserve

14.1.5.1 Annual Scheduling

By the end of September each year TSOs shall exchange data on the cross-border *NTC* for the following year (Year 1). The data shall be copied for information to the *EAPP CC*. The data shall also indicate the pre-emptive rights over the *NTC* held by the *TSO* on behalf of a *User* connected to its *National System*.

By the end of October each year, *TSOs* shall agree on the allocation of transmission capability and shall publish an Annual Interchange Schedule. This Interchange Schedule is indicative only and is used to advise *Users* of potential availability of power trading opportunities over and above those pre-emptive rights held by the *TSO* on behalf of a *User* connected to its *National System.*

14.1.5.2 Weekly Scheduling

Interchange scheduling on a weekly basis is carried out on a rolling eight (8) week cycle in accordance with OC 1 Section 8.1.9. Each Friday at 1000 Hr, *TSOs* shall agree the Interchange Schedule across their cross-border connections for the following eight (8) weeks, commencing at 0001 Hr on Monday of Week 1, including the following data:

(a) Its forecast of interchange MW profiles on an hourly basis, based on the pre-emptive rights held at the time of issue of the data to the *EAPP CC*;

(b) Confirmation of pre-emptive rights currently held on behalf of *Users*; and

(c) Details of any changes to data included in the Annual Schedule issued under this chapter.

EAPP CC shall develop the Weekly Interchange Schedule to achieve the operating reserve requirements as set out in Chapter 15 (ISBC Chapter No. 2 - Balancing and Frequency Control), and shall finalise the *NTC* based on the data received from *TSOs.*

14.1.5.3 Daily Scheduling

On a daily cycle, *TSOs* shall carry out the process of revising progressively the Weekly Interchange Schedule. This process is phased and iterative to allow:

(a) Appropriate interactions with *Neighbouring Systems, EAPP CC* and *External Systems*;

(b) Identification of changes to constraints on the *EAPP Interconnected Transmission System*;

(c) Forecasts of demand, and

(d) The *NTC* of all interconnections between *Control Areas*, *Neighbouring Systems* and *External Systems* to be determined and properly allocated.

In accordance with Chapter 8 (Operations Code No. 1 – Operational Planning) at 1500 Hr each day, *TSOs* shall finalise the *Operational Plan* for use on the following day commencing at 0001 Hr. The *Operational Plan* shall be issued and published by the *EAPP CC*. In the case of the *Operational Plan* issued on a Friday, the Plan will cover the three (3) days commencing at 0001 Hr on the Saturday. Apart from the information set out in OC 1, the *Operational Plan* will contain the following:

(a) The *NTC* between each *Control Area*, *Neighbouring Systems* and *External Systems* and its allocation between *Users*;

(b) The transfer in MW between each *Control Area*, *Neighbouring Systems* and *External Systems* on an hourly basis;

(c) The Operating Reserve levels to be maintained within the *TSO*'s *National System* on an hourly basis;

(d) The Operating Reserves contracted with other *TSOs* on an hourly basis and for which *NTC* has been reserved.

Any additional information that may be reasonably considered to be of relevance to the daily Schedule for that *TSO* shall be included. This may include:

(a) Weather;

(b) Voltage control issues;

(c) System stability issues;

(d) *System Tests* in accordance with Chapter 13 (Operations Code No. 6 - System Tests) to be carried out in another part of the *EAPP Interconnected Transmission System* which may compromise security of supply.

In real-time, neither the total of the schedules of individual *Users*, nor the actual power transfer between *Control Areas*, *Neighbouring Systems* and *External Systems* may exceed the *NTC* for that interconnection.

14.1.6 Adjustments to the Interchange Schedule

After the completion of the scheduling process, and the issuing of the Interchange Schedule,a *TSO* may consider it necessary to make adjustments to the transfers as determined by the scheduling process. Such adjustments could be made necessary by any of the following factors:

(a) Changes to *Generating Unit* availability or demand reduction;

(b) Changes to demand forecasts;

(c) Changes to *EAPP Interconnected Transmission System* constraints, emerging from the system security assessment;

(d) Changes to any conditions which in the reasonable opinion of a *TSO* or *EAPP* CC would impose an increased risk to the *EAPP* Interconnected Transmission System and would therefore require an increase in the operating reserves.

15 ISBC Chapter No. 2 - Balancing and Frequency Control

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall hold.

15.1 EAPP IC Requirements

15.1.1 Introduction

The frequency of a power system is an indicator of power balance between generation and the summation of demand and losses in the system. In the *EAPP Interconnected Transmission System*, this power balance is necessary to control system frequency and the power exchange between *Control Areas* and *External Systems*. In order to achieve this balance, each *TSO* shall ensure it has sufficient reserve capacity in order to maintain the interchange schedule within the *EAPP Interconnected Transmission System* and with *External Systems* and to control system frequency to meet the minimum standards under both normal and emergency conditions.

ISBC Chapter No. 2 - Balancing and Frequency Control, or ISBC 2, sets out the procedure which *TSOs* will use to direct frequency control. The frequency of the *EAPP Interconnected Transmission System* will be controlled by:

(a) Automatic response from synchronised *Generating Units*;

(b) The dispatch of *Generating Units* including *Automatic Generation Control (AGC)*;

(c) Response from interconnections with *External Systems*, and

(d) Demand control.

Frequency control is an Ancillary Service and *TSOs* shall contract for its provision in accordance with Chapter 16 (ISBC Chapter No. 3 - Ancillary Services), or ISBC 3.

15.1.2 Objective

The objective of the ISBC 2 is to establish:

(a) Procedures to ensure adequate operating reserves are maintained by each *TSO* when connected to the *EAPP Interconnected Transmission System*;

(b) Procedures for the minimisation of *Area Control Error (ACE)*, and

(c) Procedures for the calculation and settlement of *Inadvertent Deviation*s from scheduled interchanges.

15.1.3 Operating Reserves

Operating reserves are the additional output from *Generating Units* or a reduction in demand which are realisable in real-time operation to contain and correct any frequency deviation on the *EAPP Interconnected Transmission System*. *TSOs* shall maintain at all times adequate operating reserves to control the frequency of the *EAPP Interconnected Transmission System* within the limits set out in Section 6.1.4 (Connections), and to avoid sudden, unexpected loss of load following transmission or generation *Contingencies*. Operating reserves are also required to maintain agreed interchange schedules following changes in demand or generation.

The control of the frequency of *EAPP Interconnected Transmission System* is a multi-stage process. For every stage of control adequate reserves are needed. The Operating reserves have three components which are realisable in the following distinct timescales.

15.1.3.1 Primary Response

Primary Response is the automatic response by synchronised *Generating Units* to a rise or fall in the frequency of the *EAPP Interconnected Transmission System* requiring changes in the Generating *Unit*'s *Active Power* output, to restore the frequency to within operational limits. 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 fifteen (15) minutes.

Demand side 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.

15.1.3.2 Secondary Response

Secondary Response is a centralised automatic control that adjusts the *Active Power* production of *Generating Units* to restore the frequency and the interchanges with other *Control Areas* and with *External Systems* to their target values following a frequency deviation. *Primary Response* limits and arrests frequency deviations whilst *Secondary Response* restores the frequency to its target value.

Secondary Response is the automatic response to a frequency change which is activated within ten seconds and be fully available within ten (10) minutes 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 *Generating Units* already synchronised to the *EAPP Interconnected Transmission System* and is normally controlled by the *TSO* by *AGC* where available.

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 *EAPP Interconnected Transmission System* target frequency.

15.1.3.3 Tertiary Reserve

Tertiary Reserve refers to *TSO* instructed changes in the dispatching and commitment of *Generating Units*. *Tertiary Reserve* is used to restore both *Primary* and *Secondary Response*, to manage constraints on the *EAPP Interconnected Transmission System* and to bring the frequency and the interchanges back to their target value when the *Secondary Response* has been depleted.

Where *Tertiary Reserve* is held on *Generating Units* not synchronised to the *EAPP Interconnected Transmission System*, the Units shall be capable of being synchronised within a specified time generally between fifteen (15) minutes and one (1) hour. Non synchronised *Tertiary Reserve* could consist of, for example, fast start hydro and gas turbine *Generating Units* and steam turbine *Generating Units* on hot-standby.

Tertiary Reserve capability (ie hydro and gas turbines) in the *EAPP Interconnected Transmission System* is considered an Ancillary Service that is delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO*.

15.1.4 Distribution of Operating Reserves

Operating reserves shall be distributed evenly throughout the *EAPP Interconnected Transmission System* on *Generating Units* in operation. Possible *EAPP Interconnected Transmission System* constraints shall be taken into account by the *TSOs* and *EAPP CC* in the reserve calculation, in order to avoid a limitation in case of activation of operating reserves.

TSOs shall monitor operating reserves continuously, particularly after a loss of generation or demand and shall re-establish the required amount of reserve as soon as practicable, in order to protect against a further *Contingency* and to avoid endangering the *EAPP Interconnected Transmission System*.

15.1.5 Primary Response

The amount of *Primary Response* to be provided on the *EAPP Interconnected TransmissionSystem* shall be equal to the capacity of the largest *Generating Unit* connected to the system.

In calculating the amount of *Primary Response* required the demand-frequency response within the *Control Area* or *National System* shall be taken into account. For initial calculations the demand-frequency response can be assumed to be 1%/Hz i.e. a load decrease of 1% following a frequency drop of 1 Hz.

Each *TSO* is responsible for calculating its demand-frequency characteristic in response to a disturbance (loss of a *Generating Unit*), based on measurements of the system frequency and other key values and on a statistical analysis.

15.1.5.1 Control Area Contribution Coefficient

Each *Control Area* shall contribute to the correction of a frequency deviation in accordance with its respective contribution coefficient for *Primary Response*.

The Contribution Coefficient is the ratio of the energy generated within one year in the relevant *Control Area* to the total energy generated in the *EAPP Interconnected Transmission System.*

The contribution coefficients shall be determined by the *EAPP Sub-Committee on Operations* and published annually on January 1 for each *Control Area*. The contribution coefficients are binding for the corresponding *Control Area* for the following calendar year.

Each *Control Area* must contribute to the *Primary Response* as required. The respective shares are defined by multiplying the required *Primary Response* for the *EAPP Interconnected Transmission System* by the contribution coefficient of the *Control Area.*

The actual *Primary Responses* shall be monitored in real-time by *TSOs* and the *EAPP CC*.

15.1.5.2 Accuracy of Frequency Measurements

For *Primary Response* purposes, the accuracy of frequency measurements used in the primary controllers must be better than or equal to 10 mHz.

The insensitivity range of primary controllers shall not exceed ±10 mHz. Where dead bands exist in specific controllers, these must be reduced as much as possible.

15.1.6 Secondary Response

Each *TSO* shall operate sufficient *Generating Units* under *AGC*:

(a) To continuously balance its generation and interchange schedules to its demand, and;

(b) To provide its contribution to *EAPP Interconnected Transmission System Secondary Response* as specified below.

15.1.6.1 AGC Requirements

AGC shall continuously compare:

(a) Total net actual interchange adjusted for actual frequency and;

(b) Total net scheduled interchange adjusted for target frequency, to determine the *ACE* and respond by adjusting generation output to reduce the *ACE* to zero.

Each *TSO* shall provide adequate *Secondary Response* by *AGC* to regulate interchange and frequency and shall operate its *AGC* in tie-line bias mode, unless such operation is adverse to the reliability of the *EAPP Interconnected Transmission System*.

Secondary Response shall only be used to correct an overall system deviation and shall not be used to minimise unintentional electricity exchanges or to correct other imbalances.

15.1.6.2 Data Recording

Each *TSO* and the *EAPP CC* shall have appropriate equipment installed for the recording of all values needed for monitoring the response of secondary controllers (*AGC*) and for analysis of frequency events in the *EAPP Interconnected Transmission System*.

15.1.7 Tertiary Reserve

Tertiary Reserve is usually activated manually by *TSOs* in case of observed or expected sustained activation of *Secondary Response*. It is primarily used to release *Secondary Response* in a balanced system situation, but it is also activated as a supplement to *Secondary Response* after larger frequency deviations to restore the frequency and consequently free the system wide activated *Primary Response*.

TSOs shall, therefore, immediately activate *Tertiary Reserve* in case of large imbalances between generation and demand and or for the restoration of sufficient *Secondary Response*.

Tertiary Reserve can include the following:

(a) That part of the reserve of *Generating Units* operating in parallel with the *EAPP Interconnected Transmission System* but which has not been included in the *Primary* and *Secondary Response*;

(b) *Generating Units* that can be synchronised and loaded within specified timescales;

(c) Demand control that can be implemented on the instructions of the *TSO* within specified timescales;

(d) Standby capacity in other *TSO National Systems* that can be made available upon request and for which adequate *NTC* exists.

The amount of *Tertiary Reserve* required at the day ahead and in subsequent timescales shall be determined by each *TSO* on the basis of historical trends in the reduction inavailability of *Generating Units* and increases in forecast demand up to real-time operation.

As a minimum each *TSO* shall arrange at least enough *Tertiary Reserve* to cover the loss of the largest *Generating Unit* on its *National System*.

15.1.8 Accounting for Inadvertent Deviations

15.1.8.1 Introduction

During daily operation, the interchange schedules are followed by means of *AGC* installed in each *Control Area*. Notwithstanding *AGC*, *Inadvertent Deviation*s invariably occur in energy exchanges. For this reason, it is necessary to co-ordinate the interchange schedule between*TSOs*, observe in real-time *Inadvertent Deviation*s from the schedules and co-ordinate accounting and calculate the compensation programmes to balance unintentional deviations.

*Inadvertent Deviation*s in the *EAPP Interconnected Transmission System* shall be balanced by the import or export of an equal number of MWh at the same hours on the same day of the following week.

The measurement and accounting for *Inadvertent Deviation*s shall be carried out using metering equipment installed in accordance with the metering codes as described in Chapter 17 (Kenya Metering) and Chapter 18 (Interconnection Metering).

15.1.8.2 Recording and Compensation Periods

The standard recording period comprises seven (7) days (one week), from Monday 0001 Hr to Sunday 2400 Hr.

The standard compensation period comprises seven (7) days (one week), from Thursday 0001 Hr to Wednesday 2400 Hr. In case of holidays or for other reasons, exceptions to this rule may apply. In any case a compensation period shall last at least four (4) days and shall commence three (3) business days after the end of the corresponding recording period.

15.1.9 HVDC Interconnections

TSOs shall ensure that each *HVDC* interconnection is fitted with a fast acting control device to provide frequency response under normal and emergency operating conditions. The control device must be designed and operated to contribute to frequency control by continuous modulation of *Active Power* supplied to the *EAPP Interconnected Transmission System*.

The settings and other parameters of each *HVDC* Interconnection shall be determined by the relevant *TSOs* and the *EAPP Sub-Committee on Operations*.

15.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

The *SO* shall balance supply and demand in real time through the implementation of the energy schedules and utilisation of *Ancillary Services* based on the normal and abnormal conditions as described below.

15.2.1 Description of Normal Conditions

The KNTS is considered to be under normal conditions when:

(i) The immediate demand can be met with the available scheduled resources, including any *Contingency* resources; and
(ii) The *ACE* deficit does not exceed the available reserves for longer than ten (10) minutes; and
(iii) The frequency is not less than 49.8 Hz for a period longer than ten (10) minutes; and
(iv) The frequency is within the range 49.5 to 50.5 Hz; and
(v) The interconnections are intact; and
(vi) There are no security and safety violations

The KNTS is considered to be under abnormal conditions if it is not in a normal condition as defined above.

15.2.2 Requirements for Maintaining Normal Conditions

The *SO* shall maintain the system frequency between 49.5 and 50.5 Hz. Excursions outside of this range will be permitted for no more than 1.25% of the time, to be checked on a quarterly basis. The *SO* shall maintain voltage on the *KNTS* within +/- 10% of nominal.

15.2.3 Operation during Abnormal Conditions

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

(b) Possible 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.

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

(d) During emergencies that require load shedding, the request to shed load shall be initiated in accordance with agreed procedures prepared and published by the *SO*.

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

Table 15-1: Operation during Abnormal Conditions

Condition for Usage	Resources in Default Order of Usage
Warnings	
When a shortfall in supply is expected to occur, issue warnings in sequence until sufficient capacity is obtained to cover the shortfall	*Emergency* generation warning Interruptible load shedding warning
Generation deficit foreseen with load shedding expected	Warning to DCCs
Gradual frequency decline – refer to merit order in control room for order of use	
CONDITION FOR USAGE	**RESOURCES IN DEFAULT ORDER OF USAGE**
If frequency falls below 50 Hz and an abnormal condition exists, the *SO* shall apply resources in the order most suitable to ensure system security depending on the conditions existing at the time	(a) Run all available units at *Maximum Continuous Rating* (b) Dispatch emergency capacity according to *SO* merit order, voltage profiles, and equipment loading
Rapid Frequency Decline - Automatic Operation by Under-frequency Relays – Apply in Order	
CONDITIONS FOR USAGE	**RESOURCES IN ORDER OF USAGE**
(a) F < 49.2 Hz (b) F < 48.9 Hz (c) F < 48.6 Hz	(a) Stage 1 loads shed on select feeders* at 74MW/33 MW (Peak/Off-Peak) (b) Stage 2, 88 MW/51 MW (Peak/Off-Peak) (c) Stage 3 , 130 MW/62 MW (Peak/Off-Peak * Target loads to be determined according to the prevailing demand.
Frequency Restoration after Rapid Decline	
By the *SO*	Take restoration action as soon as possible after under frequency relays have operated

16 ISBC Chapter No. 3 - Ancillary Services

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC*. If in any instance there is a difference in requirements, the more stringent requirement shall apply.

16.1 EAPP IC Requirements

16.1.1 Introduction

The *Ancillary Services* Chapter (ASC), or ISBC 3, deals with the provision of *Ancillary Services* used to describe those services that must be exchanged among generation resources and*TNSPs* to operate the *EAPP Interconnected Transmission System* in a reliable fashion and allow separation of generation, transmission, and distribution functions.

The ASC defines those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the *EAPP Interconnected Transmission System* in accordance with *Prudent Utility Practice*. These *Ancillary Services* are required to ensure that *TSOs* meet the obligations and responsibilities under the Interconnection Code for a safe secure and reliable operation of the *EAPP Interconnected Transmission System*.

The ASC does not cover the commercial arrangements between *TSOs* and *Ancillary Service providers* for the provision of *Ancillary Services*. Such arrangements are the subject of bilateral agreements.

16.1.2 Objective

The objective of this section is to define the *Ancillary Services* to be provided by *TSOs* to support the transmission of energy across the *EAPP Interconnected Transmission System* and to maintain reliable operation.

16.1.3 Categories of Ancillary Services

The operation of *EAPP Interconnected Transmission System* requires the provision by *TSOs* of the following *Ancillary Services* grouped into three major categories:

(a) Frequency Control;

(b) Network Control, and

(c) System Restart Capability**.**

The above *Ancillary Services* are the traditional mechanisms to provide the required capability in relation to:

(a) Operating Reserves;

(b) Demand Control;

(c) Voltage Control

(d) Power Flow Control;

(e) Stability Control; and

(f) Black-Start.

The amount of each *Ancillary Service* required shall be determined by *EAPP CC* in conjunction with *Control Area Operators* in accordance with the *EAPP Interconnected Transmission System* security standards as defined in Chapter 9 (Operations Code No. 2 – Operational Security), or OC2.

16.1.3.1 Frequency Control

Frequency control *Ancillary Services* are used by *TSOs* to maintain the frequency on the *EAPP Interconnected Transmission System* within the limits set out in the CC. The *Ancillary Service* is necessary to provide for the continuous balancing of resources (generation and scheduled interchange) with load and to maintain the frequency of the *EAPP Interconnected Transmission System* at 50 Hz.

In general, frequency control action can be provided at any location within the *EAPP Interconnected Transmission System*. However, when transmission facilities are operating at or near their limits, sufficient control action is needed on each side of the limiting facility to prevent overloading of the facility.

TSOs are required to provide the following frequency control *Ancillary Services*:

(a) *Primary Response of Generating Units* in accordance with Section 6.1.8 of Chapter 6 (Connections) and Section 15.1.3 of Chapter 15(ISBC Chapter No. 2 - Balancing and Frequency Control – Operating Reserves). This *Ancillary Service* is being delivered if the *Generating Unit* is responding to changes in frequency within ten (10) seconds and is able to sustain the response for a further twenty (20) seconds;

(b) *Secondary Response of Generating Units* in accordance with Chapter 9 (Operations Code No. 2 – Operational Security) and Section 15.1.3 of Chapter 15 (ISBC Chapter No. 2 – Balancing and Frequency Control). This *Ancillary Service* is provided by *AGC* and is being delivered if the *Generating Unit's* output is correctly responding to signals sent from the *TSO's AGC* equipment in response to changes in frequency;

(c) *Tertiary Reserve* in accordance with OC 2 and ISBC 2. This *Ancillary Service* is being delivered when a *Generating Unit* is able to start up and synchronise or change its loading within the timescales specified by the *TSO*;

(d) *Demand control* in accordance with the provisions of OC 5, Chapter 12 (Operations Code No. 5 – Demand Control). This service is being delivered if:

    (i) Demand can be automatically disconnected in response to an under frequency condition (*Automatic Load Shedding*); or

    (ii) Demand can be disconnected on request from the *TSO* (Emergency Manual Load Shedding). Emergency Manual Load Shedding *Ancillary Service* can be provided by industrial load, commercial load, residential load or hydro *Generating Units* operating as pumps.

Sufficient control range should be available at all times to control frequency within the limits specified in Chapter 6 (Connections) under various circumstances including unexpected load and generation changes.

16.1.3.2 Network Control

Network control *Ancillary Service*s are primarily used to:

(a) Control the voltage at different points of the electrical network within the prescribed standards;

(b) Control the stability of the *EAPP Interconnected Transmission System*, and

(c) Control the power flow on network elements to within the physical limitations of those elements.

In accordance with the voltage standards set out in Chapter 6 (Connections), *TSO*s shall control system voltages within specific ranges. One method of controlling voltages on the *EAPP Interconnected Transmission System* is through the dispatch of voltage control *Ancillary Services*. Under these *Ancillary Services*, *Generating Units* absorb or generate *Reactive Power* from or onto the *EAPP Interconnected*

Transmission System and control the local voltage accordingly. Voltage control requirements are location dependent because of technical limitations inherent in transporting *Reactive Power*.

Stability control services are required to prevent instability following a *Contingency* which is more severe than defined for the purposes of determining *NTC*. Stability control can be achieved by *Generating Units* which can rapidly respond to a control signal to increase or decrease generation. This network *Ancillary Service* is being delivered if the *EAPP Interconnected Transmission System* remains stable after any *Contingency* (N-1) and oscillations are damped out. *Remedial Action Schemes (RAS)* are considered to be a network control *Ancillary Service*. Power flows on the *EAPP Interconnected Transmission System* shall be maintained within the *NTC* limits, as imposed by thermal ratings, stability, and voltage. In the event of a *Contingency* (N-1), equipment loadings should not exceed short-term ratings, but may exceed long-term ratings provided the loadings can be reduced to within the long-term ratings in an appropriate time period by either manual or automatic means. It is proposed to obtain network loading *Ancillary Services* by superimposing signals on the *AGC* and by emergency manual load shedding.

16.1.3.3 System Restart

Black-Start Ancillary Services are required to enable the system to be restarted following a Total or Partial System Shutdown. Following consultation with *EAPP CC, TSOs* shall arrange for appropriate *Generating Units* to provide this *Ancillary Service* in accordance with the provisions of Chapter 6 (Connections) and Chapter 10 (Operations Code No. 3 – Emergency Operations), or OC 3.

16.1.3.4 Ancillary Services Requirements

The amount and location of *Ancillary Services* will be determined by *EAPP CC* and *TSO*s as part of the *Operational Planning* Process in the Programming and Control Phases. The commitment of *Ancillary Services* in an operational situation, however, is the responsibility of individual *TSOs*.

TSOs may also contract for *Ancillary Services* with other *TSOs*. All such contracts shall be notified to *EAPP* CC.

16.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

The *SO* shall follow the procedure as described in the ISBC Chapter 15 for directing frequency control and power balance.

The *SO*shall be responsible for the provision of all short-term reliability services for the *KNTS*. These include restoration, the balancing of supply and demand, as well as the provision of quality voltages and the management of the real-time technical risk.

The *SO and Authority* shall certify providers of *Ancillary Services* and keep a register of all certified providers.

The *SO*shall determine reliability targets for the purposes of acquiring *Ancillary Services* in consultation with relevant *Users*.

The *SO* shall be responsible for optimal scheduling and dispatch of *Ancillary Services* as appropriate, in accordance with the licence and market rules. The *SO* shall state opportunities for the provision of *Ancillary Services* as identified.

The various *Ancillary Services* that can be used by the *SO* are described below:

(a) Reserves as defined in Section 16.1 of this chapter

(b) *Black Start* and unit islanding

(c) *Reactive Power* supply and voltage control from units

16.2.1 Operating Reserves

Operating reserves are required to secure capacity that will be available for reliable and secure balancing of supply and demand within ten (10) minutes and consistent with energy restrictions. Operating reserves shall consist of *Spinning Reserve*, *Regulating Reserve* and *Tertiary Reserve*. The total reserve make-up is described below.

16.2.1.1 Spinning Reserve

The provision of *Spinning Reserve* is a *Primary Response*.

The *SO* shall ensure *Spinning Reserve* is available as needed to arrest the frequency at acceptable limits following a *Contingency*, such as a unit trip or a sudden surge in load.

16.2.1.2 Regulating Reserve

The provision of *Regulating Reserve* is a *Secondary Response*.

Regulating Reserve is reserve that is under centralized *AGC* and can respond within ten (10) seconds and be fully active within thirty (30) seconds of activation and be sustained for thirty (30) minutes. This reserve is used for second-by-second balancing of supply and demand. The reserve is also used to restore *Spinning Reserve* within ten (10) minutes of the disturbance.

16.2.1.3 Tertiary Reserve

Tertiary Reserve is consistent with the EAPP definition of *Tertiary Reserve.*

Tertiary Reserve is required to balance supply and demand for changes between the day-ahead and real time such as load forecast errors and unit unavailability. *Tertiary Reserve* is used to restore *Regulating Reserve* when required.

The amount of reserve required is to be calculated by the *SO* and shall be based on *EAPP* minimum requirements and other reserve considerations.

16.2.2 Black Start and Generating Plant Islanding

Islanded *Generating Plants* shall be capable of running in the islanded state for at least two (2) hours before reconnecting to the network.

All units capable of *Generating Plant* islanding are required to contract the service provision to the *SO*. The *SO* shall certify units capable of islanding.

To ensure optimal operation of the *KNTS*, the *SO* may deploy system islanding schemes on the network, e.g. an out-of-step tripping scheme.

The *SO shall* determine the minimum requirements for each Black Start supplier and ensure that the contracted suppliers are capable of providing the service.

16.2.3 Reactive Power Supply and Voltage Control from Units

Voltage control and the supply or consumption of *Reactive Power* are inter-related in the sense that the voltage is affected by changes in the *Reactive Power* flow. System stability depends on the voltage profile across the system. In view of these considerations it is necessary from time to time to employ certain power stations to supply or consume *Reactive Power,* provided that the unit is not required to operate outside of its effective capability diagram for the purpose of voltage control.

The *SO* shall control the amount of *Reactive Power.* This may be done directly through the *Energy Management System* or by telephone.

When a unit is generating or pumping, *Reactive Power* supply is mandatory in the full operating range as specified.

17 KENYA METERING

17.1 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

The metering requirements of the *EAPP IC* deal exclusively with the metering of each point of interchange of energy between *Control Areas*. The metering requirements of the KNTGC deal primarily with metering points that do not have exchanges between *Control Areas*. The metering requirements of the two codes have many areas of similarity.

To avoid confusion regarding the two chapters that deal with metering, they have different names. The name of the metering chapter based on the *EAPP IC* is the Interconnection Metering Chapter (IMC), Chapter 18 of the *KNTGC*, and the name of the metering chapter applicable specifically to the *KNTS* is the Kenya Metering Chapter (KMC), this chapter of the KNTGC.

The IMC deals with metering of each point of interchange of energy between *Control Areas* and is not concerned with Metering of *Connection Points* between *Users* and *National Systems.*

The KMC deals primarily with metering entirely within Kenya, to which the IMC does not apply. The KMC also includes each metering point connecting Kenya's networks to a neighbouring country. The IMC applies to those inter-country connections.

Appendix B provides a complete list of standards that shall apply to *Metering Equipment*.

17.1.1 Introduction

The Kenya Metering Chapter (KMC) specifies the minimum technical, design and operational criteria to be complied with for the metering of each *Connection Point* of a *User* to the *Kenya National Transmission System.*

(a) This chapter ensures a metering standard for all current and future *Users*. It specifies metering requirements to be adhered to, and clarifies levels of responsibility.

(b) Wherever applicable, the code of practice for electricity metering shall follow nationally adopted metering standards currently in place that include KS IEC 62053, KS IEC 62054, KS IEC 62056 and KS IEC 62059 as appropriate. The *Authority* however reserves the right to override specifications should it find them inadequate or divergent from the principles of the *KNTGC*.

17.1.2 Scope

The Kenya Metering Chapter addresses the following:

(a) Application;

(b) Principles and responsibility;

(c) Installations and testing;

(d) Database, data validation, verification and inconsistencies;

(e) Data access and confidentiality.

17.1.3 Application of the Kenya Metering Chapter

This chapter shall apply to all *Users* in respect of any metering point of the *Kenya National Transmission System*.

This chapter sets out provisions relating to:

(a) *Main Metering* installations and *Check Metering* installations used for the measurement of *Active and Reactive Energy*;

(b) The collection of metering data;

(c) The provision, installation and maintenance of equipment;

(d) The accuracy of all equipment used in the process of electricity metering;

(e) Testing procedures to be adhered to;

(f) Storage requirements for metering data;

(g) Competencies and standards of performance; and

(h) The relationship of entities involved in the electricity metering industry.

17.1.4 Principles of the Kenya Metering Chapter

(a) The following points shall have a metering installation:

  (i) Each Point of Supply connecting a Transmission Licensee and *Distribution Licensee* or *End-user* to the *KNTS*.

  (ii) Each *Connection Point* between a *Generating Plant* or a *Distribution Licensee and* the *KNTS*.

  (iii) Each Point of Supply connecting *between Transmission Licensees within the KNTS*.

  (iv) Each point connecting Kenya's networks to a neighbouring country.

(b) Items 17.1.4(a)(i), 17.1.4(a)(ii) and 17.1.4(a)(iii) shall not be subject to the requirements of the IMC. Item 17.1.4 (a)(iv) shall meet all metering requirements specified in the *EAPP IC.*

(c) The type of metering installation at each metering point shall comply with the standards of Kenya Bureau of Standards or any international standard approved by the Kenya Bureau of Standards.

(d) Each metering point shall be installed with *Main* and *Check Metering* where practical and economical. *End-Users* with a maximum demand of at least 5 MVA shall have *Main* and *Check Metering*, with the same accuracy as of the main *Meter*. All CTs and VTs installed after the implementation of the KNTGC shall have separate *Main* and *Check* CT and VT cores.

(e) End-*Users* may request the installation of their own separate *Check Meters*. Any extra costs shall be borne by the requesting *Party*. The *Transmission Metering Administrator (TMA)* shall install and control such *Meters*.

(f) A metering point shall be located as close as practicable to the *Connection Point*. A metering point may be located at a point other than the *Connection Point* or the Point of Supply by mutual agreement between applicable *Users*.

17.1.5 Responsibility for Metering Installations

(a) For the purposes of this chapter, the owner of the *Meter* shall perform the role of the *Transmission Metering Administrator (TMA).*

(b) The *metering parties shall* be responsible for ensuring that all points identified as metering points in accordance with Sections 17.1.3 and 17.1.4 in this chapter have metering installations.

(c) The metering parties shall be responsible for managing and collecting metering information.

(d) *Users* connected to or wanting to connect to the *Kenya National Transmission System* shall provide the *TNSP* with all information deemed necessary to enable performance of its metering duties.

(e) In case of a material difference in location between the metering point and *Connection Point*, an adjustment for losses between these two points shall be calculated and agreed upon by the *metering parties*.

(f) The *metering parties* shall ensure that an adequate level of security is applied to the metering system with appropriate seals that will only be broken in the presence of all metering parties unless agreed otherwise.

(g) In the event of a metering installation being positioned between two *TNSPs*, the following shall apply:

(i) Both *TNSPs* shall be responsible for installing and maintaining the metering installation in accordance with the requirements of this chapter.

(ii) All costs related to this metering installation shall be borne by both *TNSPs*.

(h) In the event that a meter is found defective the matter shall be dealt with in accordance with section 159 of the Act.

17.1.6 Metering Installation Components

(a) The following principles shall apply to all metering installations:

(i) The *Meter*(s) or recorder(s) shall be able to store data in memory for forty (40) days or more.

(ii) Data stored in either a *Meter* or a recorder shall be remotely (where possible) and locally retrievable.

(iii) A *Meter* shall be remotely interrogated on a daily basis where possible or as mutually agreed by the affected *Users*.

(iv) A *Meter* shall be visible and accessible, but such access shall be restricted to authorised access only. Data for *Customer*s shall be historical data situated on a secure server. As and when required, metering impulses shall be provided.

(v) A telecommunications medium shall be connected to the *Meter*/recorder where possible.

(vi) The *Meter* data retrieval process shall be a secure process whereby *Meters* or recorders are directly interrogated to retrieve billing information from their memories.

(vii) The accuracy of *Meters* and recorders shall be in accordance with the minimum requirements of the standards of Kenya Bureau Standards or any international standard approved by the Kenya Bureau of Standards.

(viii) Commissioning of the metering installation and metering data supporting systems shall take place in accordance with the requirements of KS IEC 62056 and/or other IEC, IEEE, or currently existing local prevailing standards.

(ix) Both *Active and Reactive Energy* shall be measurable without compromising any requirements of this chapter.

(x) The *Meters* shall accurately measure both *Active and Reactive Energy* flow in both directions in accordance with of the standards of Kenya Bureau Standards or any international standard approved by the Kenya Bureau of Standards.

(xi) The *Meters* shall be configured to store/record metering data in half-hourly integration periods.

(b) In the event of a metering installation being used for purposes other than metering data

(i) Such use shall not in any way obstruct metering data collection and accuracy requirements;

(ii) The secondary use shall be communicated to all *Users* who may be affected by the secondary use of the installation;

(iii) No secondary user shall interfere with *VT/CT* circuitry.

(c) *Metering* installations shall be audited in accordance with *KS IEC standards* or equivalent.

17.1.7 Security

Each TNSP as owner of the *Metering* Equipment at the DMPs shall ensure that the equipment itself is sealed and that any links and secondary circuits are sealed where practically possible. The seals shall only be broken in the presence of representatives of the *TNSP and metering party* unless agreed otherwise by the parties involved**.**

17.1.8 Inspection, Calibration and Testing

17.1.8.1 Initial Calibration

All new meters shall be of the approved class and shall undergo relevant certification tests and initial calibration of *Meters* shall be performed in an accredited facility. These tests shall be performed in accordance with the relevant standards of Kenya Bureau of Standards or any international standard approved by the Kenya Bureau of Standards and shall confirm that Meter accuracy is within the limits stated in Section 18.9.1. A unique identifiable calibration record shall be provided before the connection is commissioned.

VTs and CTs shall be tested according to the relevant standards of Kenya Bureau of Standards or any international standard approved by the Kenya Bureau of Standards prior to installation at the DMP. The *metering parties* shall provide manufacturer's test certificates to *the Authority* to demonstrate compliance with the accuracy standards in this KMC.

17.1.8.2 Periodic Calibration and Testing

The owner of the *Metering* Equipment shall undertake calibration testing upon request by the other metering party. In addition, *the owner*shall carry out routine calibration of the *Meters* every two (2) years and connections for the CTs and VTs shall be checked every five (5) years. If the *Meters* have been adjusted to compensate for errors in the CTs and VTs, then the CTs, VTs and their connections will be checked at the same periodicity as the *Meters*.

Where, following a test, the accuracy of the *Metering* Equipment is shown not to comply with the requirements of this KMC, the *Owner of the Meter* shall take such measures as are required to restore the accuracy of the *Metering* Equipment to the required standard.

The cost of routine testing shall be met by the *Owner of the Meter.*

The cost of calibration testing shall be met by the *Party* requesting the test unless the test shows the accuracy of the *Metering* Equipment does not comply with the requirements of the KMC, in which case the cost of the tests shall be met by the *Owner of the Meter*.

The metering parties shall ensure that all *Metering* Equipment at DMPs is physically inspected and read by it or on its behalf not less than once in every three (3) months. The purpose of this reading is to reconcile cumulative register readings on site with readings collected remotely. Physical checks shall be carried out at the same time to identify such things as missing seals or damage or any other issues for concern.

Where a *Metering* Equipment is found to be faulty or to be non-compliant with the KMC, *the Authority, SO and other relevant metering parties*shall be informed of the failure or non-compliance promptly. Such notification shall include the plans by the *Owner of the meter*to restore the *Metering* Equipment to compliance with the KMC.

The *metering parties shall assess the*duration of the period when the *Metering* Equipment has been faulty. For that period recorded data from the Check *Meter* shall be used**.**

17.1.9 Metering Equipment Standards

All *Metering* Equipment shall comply with the provisions set out in the KMC. These provisions may be revised from time to time in accordance with the provision set out in Chapter 3 (General Conditions) to take account of changing technologies or new requirements of the electricity industry.

A CT in accordance with KS *IEC* 60044-1 and a VT, in accordance with KS *IEC* 60044-2 shall be provided for metering as required.

Where a combined unit measurement transformer (VT & CT) is provided the "Tests for Accuracy" in KS *IEC* Standard 60044-3 covering mutual influence effects shall be met.

All *Meters* shall include a non-volatile meter register for each measured quantity. The Meter register(s) shall not roll over more than once within the normal Meter reading cycle.

17.1.10 Equipment Accuracy and Error Limits

The accuracy of the various items of *Metering* Equipment shall conform tothe standards of Kenya Bureau Standards or any international standard approved by the Kenya Bureau of Standards. The accuracy limits set out in the KMC shall be applied after adjustments have been made to *Metering* Equipment to compensate for any errors due to secondary equipment and connections.

Meters shall be calibrated by a calibrating agency accredited by the Kenya National accreditation Service (KENAS) . The calibrating agency shall provide a calibration certificate with the expiry date of the calibration.

Where combined instrument transformers to KS *IEC* 60044-3 are used they shall meet the accuracy requirements of KMC Sections 17.1.10.1 and KMC 17.1.10.2 in this chapter.

17.1.10.1 Voltage Transformers (VT)

The VTs shall be of 0.2 Accuracy Class and comprise three (3) single phase units, each of which complies with:

(a) *KS IEC* 60044-2- Instrument Transformers : Inductive *Voltage Transformer*s, or

(b) *KS IEC* 60044-5- Capacitor *Voltage Transformer*s for metering.

The voltage drop in each phase of the VT connections will be such as to maintain the same accuracy and class and shall not exceed 0.2 Volts. The VT shall be connected through appropriate isolation and test facilities to the Meter with a total burden that shall not affect the accuracy of measurement**.**

17.1.10.2 Current Transformers (CT)

The CTs shall be of 0.2 accuracy class and comprise three (3) units for a three phase set, each of which complies with the KS *IEC* 60044-1- Instrument Transformers: *Current Transformer*s for metering.

The CT's rated secondary current shall be either 1 or 5 Amperes. The neutral conductor shall be effectively earthed at a single point and shall be connected to the Meter and other series technical equipment via separate “bridge type” isolation and test facilities with a total burden that shall not affect the accuracy of measurement.

17.1.10.3 Meters

Meters shall be of the three-element type independent for each phase, rated as appropriate and shall comply with *KS IEC TR 62052-11*: Electricity *Metering* Equipment (AC) - General requirements, tests, and testing conditions for static watt-hour Meter and other types of *Meters*, and shall be of the accuracy class of 0.2 or better.

The *Meters* shall measure and locally display at least the MW, MWh, Mvar, Mvarh, and cumulative demand, with additional features such as time-of-use, maintenance records and power quality monitoring. *Meters* shall be digital unless agreed otherwise by the *metering parties.* A cumulative register of the parameters measured shall be available on the internal storage facilities of the digital meters for a minimum of thirty (30) calendar days with one (1) hour interval values. Bi-directional *Meters* shall have two such registers available.

The loss of auxiliary supply to the *Metering* Equipment shall not erase these registers. The Meter registers shall be readable by both the *Metering Parties* and the SO’s *SCADA*.Where data storage is not provided internally it shall be provided externally to the *Metering* Equipment by way of a data logger which summates the pulse outputs of the *Meters*. The internal registers of these devices shall provide a register per measured quantity that can be interrogated by the *Metering Parties* and the SO’s *SCADA.*

17.1.11 Data Validation and Verification

17.1.11.1 Data Validation

Data validation shall be carried out in accordance with KS IEC standards.

In the event of electronic access to the *Meters* not being possible, an emergency bypass or other scheme having no metering system, or *Metering* data not being available, the following options may be resorted to by the *TMA*:

(a) Manual *Meter* data downloading;
(b) Estimation or substitution subject to mutual agreement between the affected parties;
(c) Profiling;
(d) Reading of the *Meter* at scheduled intervals.

In the event of an estimation having to be made, the following shall apply:

(a) A monthly report shall be produced for all estimations made.
(b) No estimation shall be made on three (3) or more consecutive time slots, and if such estimation had to be made, the *TMA* shall ensure that the *Meter* readings are downloaded for the billing cycle.
(c) Any logs on data estimation shall be kept for the entire period of data retention. Five (5) years' data retention shall be made available.

Not more than ten (10) slots may be estimated per Meter point per month. If such estimation had to be made, the *TMA* shall ensure that the Meter readings are downloaded for the billing cycle.

Meters needing three (3) or more consecutive estimations or a total of ten (10) or more estimations in a month shall be tracked for problems needing attention.

17.1.11.2 Meter Verification

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

17.1.12 Metering Database

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

(a) Name and unique identifier of the metering installation
(b) The date on which the metering installation was Commissioned
(c) The connecting parties at the metering installation
(d) Maintenance history schedules for each metering installation
(e) Telephone numbers used to retrieve information from the metering installation
(f) Type and form of the Meter at the metering installation
(g) Fault history of a metering installation
(h) Commissioning documents for all metering installations
(i) Physical georeferenced location of the meter
(j) Single line diagram indicating the metering point

Information relating to raw and official values shall form part of the metering database and shall be retained for at least five (5) years for audit trail purposes.

17.1.13 Testing of Metering Installations

(a) Commissioning, auditing and testing of metering installations shall be done in accordance with the KS IEC metering specifications.
(b) Any *User* may request from the other metering party for testing of a metering installation be performed. Such a request shall not be unreasonably refused. The costs of such test shall be for the account of the requesting *User* if the *Meter* is found to be accurate and to the account of the *TMA* if the Meter is found to be inaccurate. If errors are found with the metering after testing or auditing, the requesting *User*'s account will be adjusted according to the rectified Data.

17.1.14 Metering Database Inconsistencies

In the event of testing revealing that data in the metering database is inconsistent with the data in the Meter, the *TMA* shall inform all affected *Users* and corrections shall be made to the official metering data in all the impacted areas.

17.1.15 Access to Metering Data

(a) *Metering* data shall be accessed through a central database that shall store all *Customer* information.
(b) The *TMA* shall control access to all metering installations.
(c) No electronic access to the *Meters* shall be granted to the *Customer* or any other *Party* unless special permission has been granted by the *Authority*.

(d) Schedules for accessing metering data from the central database shall be administered by the *TMA* in line with IEC specifications

(e) All Security requirements for metering data shall be as specified in KS IEC 62056.

17.1.16 Confidentiality

Metering data and passwords are confidential information and shall be treated as such at all times.

17.1.17 Customer Query on Metering Integrity and Metering Data

If a *User* has a query or complaint related to metering, the relevant *TMA* shall comply with the applicable requirements as per KS IEC 62056.

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18 INTERCONNECTION METERING

18.1 EAPP IC REQUIREMENTS

The metering requirements of the *EAPP IC* deal exclusively with the metering of each point of interchange of energy between *Control Area*s. The metering requirements of the *KNTGC* deal primarily with metering points that do not have exchanges between *Control Areas*. The metering requirements of the two Codes have many areas of similarity.

18.1.1 Introduction

The Interconnection Metering Chapter (IMC) specifies the minimum technical, design, and operational criteria to be complied with for the metering of each point of interchange of energy between *Control Areas*. The metering at the *Interchange Point* is required for real-time operation of *AGC* systems and for the accounting of *Inadvertent Deviation*s in accordance with the Chapter 15 (ISBC Chapter No. 2 – Balancing and Frequency Control). The IMC also specifies the associated Data Collection and the related metering procedures required for the operation of the *EAPP Interconnected Transmission System*.

The IMC is not concerned with:

(a) *Metering* of *Connection Points* between *Users* and *National Systems,* and

(b) *Metering* for commercial purposes.

These metering systems are subject to National Grid Codes or Regulations and or Power Purchase Agreements.

18.1.2 Objectives

For the metering of the interconnections between *Control Areas* of the *EAPP Interconnected Transmission System* and between *Control Areas* and *External Systems*, the IMC specifies the conditions governing the following:

(a) Technical, design and operational criteria;

(b) Accuracy and calibration;

(c) Approval, certification and testing, and

(d) *Meter* reading and data management

18.1.3 Technical Design and Operational Criteria

Metering equipment shall be installed and maintained to measure and record the hourly *Active a*nd *Reactive Energy* and *Active* and *Reactive Power* transferred to and from a *Control Area* at its *Interconnection Point (IP)* with other *Control Areas* and or *External Systems*. This *Metering* Equipment will be the primary source of data for *TSOs* to operate *AGC* systems in real-time and to account for *Inadvertent Deviations.*

TSOs are responsible for the maintenance and operation of the *Metering* Equipment at each *IP* and shall be responsible for the initial design, installation, testing and commissioning of the *Metering* and Check *Metering* Equipment.

Main and Check *Metering* Equipment procured, installed, operated and maintained for the purpose of the IMC shall meet the standards of accuracy and calibration in relation to *Meters* and *Metering* Equipment as set out in this IMC.

18.1.3.1 General Technical Criteria

This section defines the general technical requirements for the *Metering* Equipment for the measurement and recording of electricity transfers on the interconnections between *Control Areas* and between *Control Areas* and *External Systems*. The provisions of the IMC shall apply equally to Main and Check *Meters*.

TSOs and the *EAPP CC* shall establish metering related policies, procedures and standards in support of the IMC including, but not limited to registration, testing and calibration, sealing, loss adjustments, data security, inspection, testing and audit of *Metering* Equipment and measurement error correction.

18.1.4 Metering Information Register

EAPP CC shall maintain a *Meter* Information Register of all *Meters* at Defined Metering Points (DMPs). This register will contain, but not be limited to:

(a) A unique *Meter* identification/serial number;

(b) Location of the Main *Meters*, Check *Meters* and *Metering* Equipment including metering data recording systems;

(c) The identification of the *TSO* concerned;

(d) *Meter* manufacturer, type and model;

(e) The specification of *Metering* Equipment including accuracy class;

(f) The adjustment factors including circuit losses to be applied;

(g) Date of installation; and

(h) Calibration certificate.

18.1.5 Main and Check Metering

At all DMPs Main and Check *Metering* shall be provided. Main and Check *Meters* shall operate from separate *Current Transformer (CT) and Voltage Transformer (VT)* windings. All Check *Meters* shall meet the standards specified in the IMC as if they were the only *Metering* Equipment at the DMP.

CT and VT windings and cables connecting such windings to Main *Meters* shall be dedicated for such purposes and such cables and connections shall be securely sealed.

CT and VT windings and cables connecting such windings to Check *Meters* may be used for other purposes provided the overall accuracy requirements are met and evidence of the value of the additional burden is available for inspection by or on behalf of the *EAPP Independent Regulatory Board*.

The Main *Meter*, Check *Meter* and additional burdens shall have separately fused VT supplies.

18.1.6 Measurement Parameters

For each DMP, the *Metering* Equipment shall be capable of measuring the following parameters in both import and export directions: MW, Mvar, MWh and Mvarh.

18.1.7 Metering Equipment Standards

All *Metering* Equipment shall comply with the provisions set out in the IMC. These provisions may be revised from time to time in accordance with the provision set out in Chapter 3 (General Conditions) to take account of changing technologies or new requirements of the electricity industry.

A CT in accordance with *IEC* 60044-1 and a VT, in accordance with *IEC* 60044-2 shall be provided for metering as required.

Where a combined unit measurement transformer (VT & CT) is provided the "Tests for Accuracy" in Clause 8 of *IEC* Standard 60044-3 covering mutual influence effects shall be met.

All *Meters* shall include a non-volatile meter register for each measured quantity. The Meter register(s) shall not roll over more than once within the normal Meter reading cycle.

18.1.8 Equipment Accuracy and Error Limits

The accuracy of the various items of *Metering* Equipment shall conform to the relevant *IEC* standards or equivalent national standards where agreed between the *EAPP CC* and the *TSO* concerned. The accuracy limits set out in the IMC shall be applied after adjustments have been made to *Metering* Equipment to compensate for any errors due to secondary equipment and connections.

Meters shall be calibrated by an independent calibrating agency approved by the *EAPP Independent Regulatory Board* for this purpose. The agency shall provide a calibration certificate with expiry date of the calibration.

Where combined instrument transformers to *IEC*60044-3 are used they shall meet the accuracy requirements of IMC Sections 18.1.9.1 and IMC 18.1.9.2 in this chapter.

18.1.8.1 Voltage Transformers (VT)

The VTs shall be of 0.2 Accuracy Class and comprise three (3) single phase units, each of which complies with:

(a) *IEC* Standard 60044-2: Instrument Transformers - Part 2: Inductive *Voltage Transformer*s, or

(b) *IEC Standard* 60044-5 Part 5: Capacitor *Voltage Transformer*s for metering.

The voltage drop in each phase of the VT connections will be such as to maintain the same accuracy and class and shall not exceed 0.2 Volts. The VT shall be connected through appropriate isolation and test facilities to the Meter with a total burden that shall not affect the accuracy of measurement**.**

18.1.8.2 Current Transformers (CT)

The CTs shall be of 0.2 accuracy class and comprise three (3) units for a three phase set, each of which complies with the *IEC* Standard 60044-1: Instrument Transformers - Part 1: *Current Transformer*s for metering.

The CT's rated secondary current shall be either 1 or 5 Amperes. The neutral conductor shall be effectively earthed at a single point and shall be connected to the Meter and other series technical equipment via separate "bridge type" isolation and test facilities with a total burden that shall not affect the accuracy of measurement.

18.1.8.3 Meters

Meters shall be of the three-element type independent for each phase, rated as appropriate and shall comply with *IEC* Standard 62052-11: Electricity *Metering* Equipment (AC) - General requirements, tests, and testing conditions for static watt-hour Meter and other types of *Meters*, and shall be of the accuracy class of 0.2 or better.

The *Meters* shall measure and locally display at least the MW, MWh, Mvar, Mvarh, and cumulative demand, with additional features such as time-of-use, maintenance records and power quality monitoring. *Meters* shall be digital unless agreed otherwise by *EAPP CC*. A cumulative register of the parameters measured shall be available on the internal storage facilities of the digital meters for a minimum of thirty (30) calendar days with one (1) hour values. Bi-directional *Meters* shall have two such registers available.

The loss of auxiliary supply to the *Metering* Equipment shall not erase these registers. The Meter registers shall be readable by both the *TSO's SCADA* and by the *DCS* of *EAPP CC*. Where data storage is not provided internally it shall be provided externally to the *Metering* Equipment by way of a data logger which summates the pulse outputs of the *Meters*. The internal registers of these devices shall provide a register per measured quantity that can be interrogated by the *TSO's SCADA* system and by the *DCS* of *EAPP CC.*

18.1.9 Inspection, Calibration and Testing

18.1.9.1 Initial Calibration

All new meters shall undergo relevant certification tests and initial calibration of *Meters* shall be performed in a recognised test facility. These tests shall be performed in accordance with the relevant *IEC* standards and shall confirm that Meter accuracy is within the limits stated in Section 18.9.1. A unique identifiable calibration record shall be provided before the connection is commissioned.

VTs and CTs shall be tested according to the relevant *IEC* standards prior to installation at the DMP. The *TSO* shall provide manufacturer's test certificates to *EAPP CC* to show compliance with the accuracy standards in this IMC.

18.1.9.2 Periodic Calibration and Testing

The *TSO* as owner of *Metering* Equipment shall undertake calibration testing upon request by the *EAPP Independent Regulatory Board* or another *TSO*. In addition, *TSOs* shall carry out routine calibration of the *Meters* every three (3) years and connections for the CTs and VTs shall be checked every five (5) years. If the *Meters* have been adjusted to compensate for errors in the CTs and VTs, then the CTs, VTs and their connections will be checked at the same periodicity as the *Meters*.

Where, following a test, the accuracy of the *Metering* Equipment is shown not to comply with the requirements of this IMC, the *TSO* shall take such measures as are required to restore the accuracy of the *Metering* Equipment to the required standard.

The cost of routine testing shall be met by the *TSO* as owner of the *Metering* Equipment.

The cost of calibration testing shall be met by the *Party* requesting the test unless the test shows the accuracy of the *Metering* Equipment does not comply with the requirements of the IMC, in which case the cost of the tests shall be met by the *TSO*.

TSOs shall ensure that all *Metering* Equipment at DMPs is physically inspected and read by it or on its behalf not less than once in every three (3) months. The purpose of this reading is to reconcile cumulative register readings on site with readings collected remotely. Physical checks shall be carried out at the same time to identify such things as missing seals or damage or any other issues for concern.

Where a *Metering* Equipment is found to be faulty or to be non-compliant with the IMC, *EAPP CC* and the other relevant *TSO* shall be informed of the failure or non-compliance promptly. Such notification shall include the plans by the *TSO* concerned to restore the *Metering* Equipment to compliance with the IMC.

The *EAPP CC* shall in cooperation with the *TSOs* involved assess the duration of the period where the *Metering* Equipment has been faulty. For that period recorded data from the Check *Meter* shall be used.

18.1.10 Data Collection

The *TSO* shall collect all data relating to the parameters measured by *Metering* Equipment at DMPs by remote or manual on-site interrogation in accordance with the terms of this IMC. For the purposes of remote interrogation the *TSO* may use its own data communications network or failing this, shall enter into, manage and monitor contracts to provide for the maintenance of all data links by which data is passed to the *TSO* and to the *EAPP CC*. In the event of any fault or failure on such communication links or any error or omission in such data the *TSO* shall, if possible, retrieve such data by manual on-site interrogation.

18.1.11 Security

Each TSO as owner of the *Metering* Equipment at the DMPs shall ensure that the equipment itself is sealed and that any links and secondary circuits are sealed where practically possible. The seals shall only be broken in the presence of representatives of the *EAPP Independent Regulatory Board* and the *TSO* unless agreed otherwise by the parties involved**.**

18.1.12 Disputes

*Dispute*s concerning this IMC will be dealt with in accordance with the procedures set out in Section 3.11 of Chapter 3 (General Conditions - Dispute Resolution).

18.1.13 Meter Data Confidentiality

Meter data may be commercially sensitive and confidential and appropriate measures shall be taken to ensure the meter data cannot be divulged to or obtained by third-parties**.**

18.1.14 Operational Metering

An operational metering system is required to support real time operation of the *EAPP Interconnected Transmission System*. Because operational requirements differ from Interchange *Metering* requirements, the operational metering system does not necessarily have the same requirements for accuracy of measurement. However, timely operational metering data is critical for the efficient, safe, and timely operation of the *EAPP Interconnected Transmission System*. *EAPP CC* and *TSOs* shall agree on the types of operational data to be exchanged in real-time and shall ensure that appropriate systems are in place.

19 DATA EXCHANGE (SYSTEM MODELING DATA)

19.1 INTRODUCTION

The Data Exchange Chapter (DEC) defines the system data to be exchanged between *TSOs* and *EAPP Sub-Committees on Planning and Operations* for the purpose of the modelling and analysis of steady-state and dynamic conditions for the *EAPP Interconnected Transmission System*.

The DEC sets out the information flows required between *TSOs* and *EAPP Sub-Committees on Planning and Operations* to produce *EAPP* system models for the various processes that require system studies to be undertaken.

These processes include those associated with System Planning as set out in the PC, including the preparation of the *Transmission System Capability Statement*, and with *Operational Planning* as set out in OC 1, Chapter 8 (Operations Code No. 1 – Operational Planning).

19.2 OBJECTIVE

The objectives of the DEC are:

(a) To detail how *EAPP* system models are produced and agreed;
(b) To address the methods of information management across the interface between *EAPP Sub-Committees on Planning and Operations* and *TSOs* to ensure consistency of the *EAPP* system model, and
(c) To provide a basis for cooperation between *EAPP Sub-Committees on Planning and Operations* and *TSOs* in the field of power system analysis. The power system analysis studies are required in order to resolve balance and capacity problems and for secure exploitation of the advantages of the *EAPP Interconnected Transmission System*.

19.3 POWER SYSTEM MODEL

Power System Model refers to the power system data that are needed in order to carry out load flow, fault, transient and dynamic studies on all or part of the *EAPP Interconnected Transmission System*.

The Model will characterise *Generating Unit* responses to system disturbances such as voltage and frequency deviations, and oscillations and control signals for power and voltage scheduling. The dynamic model will be part of the Power System Model used in the system studies to determine operating transfer limits and system reinforcements.

Power system studies are required for two distinct purposes:

19.3.1 System Planning

System planning studies generally involve studies of the system from three (3) years to ten (10) years ahead. They identify deficient areas in the transmission and generation systems and solutions are proposed which may include facility additions, upgrades, or other modifications. Studies are performed for all projected seasonal periods. Generation output in the study case is based on the principles of economic dispatch. The combination of load and capacity studied is a snapshot of projected *EAPP Interconnected Transmission System* conditions and therefore subject to a degree of uncertainty. Additional studies may need to be performed to evaluate off-peak periods and study specific *Outages* of transmission and generation facilities.

19.3.2 Operational Planning

Operational Planning studies are normally performed for conditions from three (3) years ahead down to real time. These studies identify *Contingency* related transmission deficiencies that may be encountered, and assist in formulating corrective measures in operational timescales to mitigate the deficiency.

19.4 PROVISION OF SYSTEM DATA

TSOs shall provide data of two types:

19.4.1 Basic Data

The *EAPP Sub-Committee on Planning* shall prepare the basic data for use in system studies. The data shall be prepared annually with input from *TSOs*. The basic data shall include the electrical characteristics and ratings of transmission facilities and the timing of new facilities maintained in a chronological database. Basic datasets shall be produced by the *EAPP Sub-Committee on Planning* for each year up to ten (10) years ahead.

The system data to be provided by *TSOs* to the *EAPP Sub-Committee on Planning* is set out in Section 19.8 of this chapter.

19.4.2 Study Data

In order to carry out system studies in accordance with the requirements for Planning or Operations, *TSOs* shall supply appropriate system data to the *EAPP Sub-Committees on Planning and Operations*. This data includes, but is not limited to, the following:

(a) The demand on the *EAPP Interconnected Transmission System* for the period under study. The distribution of demand across the nodes shall be consistent with the period under study;
(b) Generation indicative of the conditions under study. Generation in individual *National Systems* shall be based on that system's economic dispatch with base load units, hydrological factors, pumped storage and distributed generation given proper consideration;
(c) Evaluation of Transmission System Capability;
(d) Interchange with *External Systems* modelled as demand or generation as the case may be. Equivalents of the *External Systems* shall be used if studies other than load flow are being carried out;
(e) Ratings of transmission facilities based on appropriate ambient temperature and seasonal conditions;
(f) Timing of new facilities and *Outage* schedules for existing facilities; and
(g) A list of *Contingencies* to be considered during programme execution agreed between *TSOs* and *EAPP Sub-Committees on Planning and Operations*.

19.5 RESPONSIBILITY FOR SYSTEM MODELS

The *EAPP Sub-Committee on Planning* shall be responsible for the coordination and production of the *EAPP Interconnected Transmission System* models and shall define the software to be used in *EAPP* executed studies.

TSOs are responsible for the production of models of their own *National Systems* and they may determine the software to be used. If the software is different from that in use by *EAPP* then appropriate data format conversion shall be carried out. The data shall be the latest version available unless a specific version of the data is requested and in all cases the data must be complete.

EAPP Sub-Committee on Planning shall perform data verification to ensure correct *TSO* model conversion, that the system configuration is maintained, and that the parameters for all lines, transformers, and reactors are properly converted. The *EAPP Sub-Committee on Planning* shall maintain a database of all problems encountered during data conversion and the solutions found.

19.6 EQUIVALENTS

An equivalent is a simplified version of the complete *EAPP Interconnected Transmission System* model. Equivalents can be supplied to and used by third-parties for their studies. The aim is that the characteristics of the equivalent at the *Connection Points* should be the same as those of the complete model in terms of load distribution, impedances, and dynamic response.

19.7 DATA CONFIDENTIALITY

Where the data exchanged between *TSOs and EAPP* Sub-Committees on Planning and Operations is not in the public domain in the country to which it refers, the data shall be considered confidential in accordance with Section 3.15 in Chapter 3 (General Conditions – Confidentiality).

19.8 BASIC DATA REQUIREMENTS

List of Basic Data required by *EAPP* for use in the Power System Model

(a) **Substation:** name, nominal voltage, demand supplied (consistent with the aggregated and dispersed substation demand data supplied) and location.

(b) **Generating Units (including synchronous condensers, pumped storage, etc.):** location, minimum and maximum Ratings (net *Real and Reactive Power*), regulated bus and voltage set point, and equipment status.

(c) **AC Transmission Line or Circuit (overhead and underground):** nominal voltage, impedance, line charging, Normal and Emergency Ratings, equipment status, and metering locations.

(d) **HVDC Transmission Line (overhead and underground):** line parameters, Normal and Emergency Ratings, control parameters, rectifier data, and inverter data.

(e) **Transformer (voltage and phase-shifting):** nominal voltages of windings, impedance, tap ratios (voltage and/or phase angle or tap step size), regulated bus and voltage set point, Normal and Emergency Ratings and equipment status.

(f) **Reactive Compensation (shunt and series capacitors and reactors):** nominal Ratings, impedance, percent compensation, connection point, and controller device.

(g) **Interchange Schedules:** Existing and future Interchange Schedules and/or assumptions.

Notes

(a) Design data shall be provided for new or refurbished excitation systems (for *Synchronous Generating Units* and synchronous condensers) at least three (3) months prior to the installation date.

(b) Unit-specific dynamics data shall be reported for *Generating Units* and synchronous condensers (including, as appropriate to the model, items such as inertia constant, damping coefficient, saturation parameters, and direct and quadrature axes reactances and time constants), excitation systems, voltage regulators, turbine-governor systems, power system stabilisers, and other associated generation equipment.

(c) Estimated or typical manufacturer's dynamics data, based on units of similar design and characteristics, may be submitted when unit-specific dynamics data cannot be obtained.

(d) The Interconnection-wide requirements shall specify unit size thresholds for permitting:

(i) The use of non-detailed vs. detailed models,

(ii) The netting of small generating units with bus load, and

(iii) The combining of multiple generating units at one plant.

(e) Device specific dynamics data shall be reported for dynamic devices, including, among others, static VAR controllers, high voltage direct current systems, flexible AC transmission systems, and static compensators.

20 INFORMATION EXCHANGE

20.1 INTRODUCTION

This chapter defines the reciprocal obligations of parties with regard to the provision of information for the implementation of the *KNTGC*. The information requirements, as defined for the *TNSP,* the *SO,* the *Authority and Users*, are necessary to ensure non-discriminatory access to the *Kenya National Transmission System (KNTS)* and the safe, reliable provision of transmission services.

The information requirements are divided into planning information, operational information and post-dispatch information.

Information criteria specified in the Information Exchange Chapter are supplementary to the other chapters within the *KNTGC*. In the event of inconsistencies between other chapters and the Information Exchange Chapter with respect to information exchange, the requirements of the Information Exchange Chapter shall prevail.

Requirements in this chapter apply to communications between the *Authority, SO, Licensees* and *Users*.

20.2 INFORMATION EXCHANGE INTERFACE

(a) The parties shall identify the following for each type of information exchange:

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

  (ii) The names, contact details of, and the parties represented by persons requesting the information

  (iii) The purpose for which the information is required.

(b) The parties shall agree on appropriate procedures for the transfer of information.

20.3 SYSTEM PLANNING INFORMATION

(a) *Users* shall provide such information as the *TNSP* and/or the *SO* may reasonably request on a regular basis for the purposes of planning and developing the *KNTS*. Each request shall specify the information sought and the requested frequency upon which it would be provided. *Users* shall submit the information within the specified time period without unreasonable delay. Such information may be required for the planning and development of the *KNTS*, monitoring current and future power system adequacy and performance, and fulfilling statutory or regulatory obligations. Reasons for any anticipated delay in providing the requested information shall be communicated for effective mitigation.

(b) *Users* shall submit to the *TNSP* and/or *the SO*the following information. The *TNSP* and/or *SO*may request additional information reasonably required.

  (i) Hourly/daily/monthly load forecast data, and the source of the forecast

  (ii) Transmission system losses data with indication of percent losses included in the load forecast

  (iii) Identification of non-conforming load data

  (iv) Demand response (DR) resources

  (v) Network topology, and capacity/rating data

  (vi) Daily list of transmission reservations to and hourly increment of new reservations, if any

(vii) Transmission system connected transformer data
(viii) Shunt capacitor or reactor data requirements
(ix) Series capacitor or reactor data requirements
(x) Phase shifting transformers
(xi) *Flexible* AC *Transmission System (FACTS)* devices
(xii) *High* voltage *direct current (HVDC)* data
(xiii) Information on *Customer* networks
(xiv) Overhead line data
(xv) Cable data

(c) *Generation Licensees* shall submit to the *TNSP* and/or *SO* the following information for *Generating Plants*. The *TNSP* and/or *SO* may request additional information reasonably required.

(i) *Generating Plant* data including regulated bus, target voltage and actual voltage
(ii) *Generating Plant* data including unit owner and bus location in the model, seasonal ratings, P_{MIN}, P_{MAX}, Q_{MIN}, Q_{MAX}
(iii) Rules for sharing output between joint owners, if any
(iv) Station auxiliaries to the extent gross generation has been reported
(v) Reserve capability
(vi) Unit parameters
(vii) Excitation system
(viii) Control devices and protection relays
(ix) *Generating Plant* step-up transformer
(x) *Generating Plant* forecast data
(xi) Mothballing of *Generating Plants and/or units*
(xii) Return to service of mothballed *Generating Plants*
(xiii) Decommissioning of *Generating Plants and/or units*
(xiv) De-rating *of Generating Plants and/or units*

(d) *Users shall* submit to the *TNSP* and/or *SO* and to all other relevant *TNSPs their* planning schedules, including a ten-year demand forecast and information on embedded *Generating Plants* larger than five (5) MVA.

(e) The *TNSP* shall provide the *Generation Licensee*s with information about equipment and systems installed in HV yards, including:

(i) Circuit breaker
(ii) *Current transformer* (CT) and *Voltage Transformer*(VT)
(iii) Surge arrestor
(iv) Protection
(v) Power consumption
(vi) Link
(vii) Outgoing feeder
(viii) Transformer
(ix) Compressed air system
(x) Fault recorder
(xi) Fault levels

(f) The *TNSP* and/or the *SO* shall keep an updated technical database of the *KNTS* for purposes of modelling and studying the behaviour of the *KNTS*.

(g) The *TNSP* and the *SO*shall provide *Users* or potential *Users*, upon any reasonable request, with any relevant information that they require to properly plan and design their own networks/installations or comply with their other obligations in terms of the *KNTGC*

(h) The *TNSP* and/or the *SO*shall provide all relevant information related to network planning.

(i) *Users* shall, upon request to upgrade an existing connection or when applying for a new connection, provide the *TNSP* and the *SO*with information relating to Table 20-1 below:

Table 20-1: Required Information

Item	Description
Commissioning	Projected or target Commissioning test date
Operating	Target operational or on-line date
Reliability of connection requested	Number of connecting circuits, e.g. one or two feeders, or firm/non-firm supply required, subject to Chapter 6 (Connections).
Location map	Upgrades: name of existing point of supply to be upgraded and supply voltage New connections: provide a 1:50 000 or other agreed scale location map, with the location of the facility clearly marked. In addition, co-ordinates of the Connection Point to be specified
Site plan	Provide a plan of the site (1:200 or 1:500) of the proposed facility, with the proposed point of supply, and where applicable, the transmission line route from the facility boundary to the point of supply, clearly marked
Electrical single line diagram	Provide an electrical single-line diagram of the User intake substation

(j) The *TNSP* and/or *SO* may estimate any system planning information not provided by a *User* as specified in items (b) and (c) above. The *TNSP* and/or *SO* shall take all reasonable steps to reach agreement with the *User* on estimated data items. The *TNSP* and/or *SO*shall indicate to the *User* any data items that have been estimated. The obligation to ensure the correctness of data remains with the *User*.

(k) *Generation Licensee*s shall submit weekly to the *TNSP* and/or *SO*all maintenance planning information requested with regard to each unit at each *Generating Plant* as well as transmission switching.

(l) The *TNSP* shall provide the *Generation Licensee*s with a monthly rolling maintenance schedule for all planned work in HV yards for a period of one year in advance. Log books on all vessels under pressure for receivers installed in HV yards shall be made available on request from the *Generation Licensee*.

(m) *Notification* to the SO of all forced *Outage*s of both generation and transmission resources shall not exceed thirty (30) minutes after they are identified.

20.4 OPERATIONAL INFORMATION

20.4.1 Pre-Commissioning Studies

(a) *Users* shall meet all system planning information requirements before the Commissioning test date. (This will include confirming any estimated values assumed for planning purposes or, where practical, replacing them with validated actual values and with updated estimates for the future.)

(b) The *TNSP* shall perform pre-Commissioning studies prior to sanctioning the final connection of new or modified plant to the *KNTS*, using data supplied by *Users* in accordance with Section 20.3, to verify that all control systems are correctly tuned and planning criteria have been satisfied.

(c) The *TNSP* may request adjustments prior to Commissioning should tuning adjustments be found to be necessary. The asset owner shall ensure that all system planning information records are maintained for reference for the duration of the operational life of the plant. Information shall be made available within a reasonable time on request from the *TNSP* upon notification of such a request.

20.4.2 Commissioning and Notification

(a) All *Users* shall ensure that exciter, turbine governor, *Flexible AC Transmission System (FACTS) and High Voltage Direct Current (HVDC)* control system settings are implemented and are as finally recorded by the SO prior to Commissioning.

(b) *Users* shall give the *SO* notice of the time at which the Commissioning tests will be carried out. The *SO* and the *User* shall agree on the timely provision of operational data items.

(c) Records of Commissioning shall be maintained for reference by the asset owner for the operational life of the plant and shall be made available, within a reasonable time, to the *SO* upon notification of such request.

(d) The asset owner shall, before the equipment is returned to service, communicate to the *TNSP* and/or *SO*changes made to Commissioned equipment during an *Outage*. The *TNSP* and/or *SO*shall keep Commissioning records of operational data for the operational life of the plant connected to the *KNTS*.

(e) *Users* shall also provide notification on:

   (i) Planned and actual operation0al start-up dates for any permanently added, removed or significantly altered transmission segments;

   (ii) Planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units.

20.4.3 General Data Acquisition Information Requirements

The *SO*shall have adequate observability to ensure reliable and safe operation of the *KNTS*. *Users* are to comply with reasonable requests from the *SO*that are intended to ensure adequate observability. The *SO*will ensure confidential treatment of data, as discussed in Section 3.15.

(a) *Users* and *TNSP*s shall agree on the formats to be used for the measurements and indications to be supplied to the *SO.* Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information, such *User* shall report and restore or correct the signals and/or indications as soon as reasonable.

(b) The *SO* shall notify the *User*, where the *Kenya National TSO*, acting reasonably and in consultation with the *User*, determines that additional measurements and/or indications in relation to a *User*'s plant and equipment are needed to meet a *KNTS* requirement. The costs related to the *User*'s modifications for the additional measurements and/or indications shall be for the account of the providing *User*.

(c) On receipt of such notification from the *SO* the *User* shall promptly ensure that such measurements and/or indications are made available at the unit's communications gateway equipment.

(d) The data formats to be used and the fields of information to be supplied to the *SO* by the various *Users* shall be agreed among the parties.

(e) The *TNSP* shall provide periodic feedback to *Users* regarding the transmission power flows, bus voltages, and status of equipment and systems installed in the substations where they are connected to the *KNTS*. The feedback shall include results from tests, condition monitoring, inspections, audits, failure trends and calibration. The frequency of the feedback shall be determined in the operating agreement, but will not exceed one year.

(f) Plant status reports provided by the *TNSP* will also include *Contingency* plans where applicable.

(g) The *SO* needs to inform *Users* where in the network out-of-step relays are installed, and how the relays are expected to operate. Furthermore, the characteristics of such an islanded network shall be provided, based on the most probable local network configuration at such a time.

(h) The cost of the installation of the *Data Terminal Equipment (DTE)* will be paid for by the *User*.

(i) The *User* shall decide on the location of the data terminal equipment.

(j) The *User* will be responsible for the maintenance of communications links between the *Generating Plant* gateway and the data terminal equipment.

(k) The *SO* shall be responsible for the maintenance, upkeep, and communications charges of the DTE.

(l) *Users* shall exchange *SCADA* data that shall include:

   (i) breaker statuses including *Generating Plant* breaker status;

   (ii) analogue measurements (flows and voltages);

   (iii) *Generating Plant* MW and Mvar;

   (iv) load MW and Mvar;

   (v) balancing area net interchange, operating reserve, and instantaneous demand.

(m) Parties shall provide detailed EMS model data to the *TSO* once a year in a mutually agreed-upon electronic *format* with updates as new data becomes available as current and up-to-date representation of the EMS models become important for reliability coordination and market operations.

(n) *Users* shall comply with all governing confidentiality agreements relating to information exchange.

20.4.4 Unit & Plant Scheduling

20.4.4.1 Schedules

(a) The *SO* shall arrange for the provision of sufficient energy and *Ancillary Services* to maintain system reliability.

(b) *Dispatchable Resources shall* declare to the *SO*their hourly unit available capacity or hourly load (in case of *Customers* participating as demand side resources) for the next day by 1400 Hr each day.

(c) The *SO*shall provide final day-ahead power and *Ancillary Service* schedules to *Dispatchable Resources* not later than 1600 Hr.

(d) On the day, the *SO*shall, at least ten (10) minutes before the hour, notify *Dispatchable Resources* of deviations in power and *Ancillary Service* schedules, subject to unit constraints.

(e) In the event that *Dispatchable Resource* availability changes, the *Dispatchable Resource* shall notify the SOpromptly.

(f) All information exchange requirements for *Ancillary Services* that are contracted annually shall be included in the contract between the parties.

(g) If the *Dispatchable Resource* provides a schedule more than a day in advance and provides no update to the previously provided schedule by 1400 Hr on the day-ahead, the *SO*shall use the most recently provided schedule.

(h) At the discretion of the *SO,* the *Dispatchable Resource* will submit a daily energy schedule, which the *SO*will use to determine the hourly power and *Ancillary Service* schedule of the *User*, subject to the unit and/or hydrological constraints.

(i) *Renewable Power Plants* should provide forecasts as specified in Section 7.2.11.

20.4.4.2 File Transfers

The applicable *User* and the *SO*shall agree on the format of the file used for data transfer. The data shall be made available in a common, electronically protected directory. All file transfer data shall be fetched by the *SO*.

Table 20-2: File Transfers

File	Description	Trigger Event	Frequency
Dispatch schedule	The combined 24-hour day-ahead energy and *Ancillary Services* schedules. Hourly day-ahead contracts for different market categories that identify the unit with the next 24 hourly values for it	Generation dispatch schedule	Daily
Dispatch cost curve	Daily cost curve with incremental costs and corresponding volumes	Generation dispatch schedule	Daily

20.4.5 Inter Control Centre Communication

(a) *Users* shall provide the *SO* on request with network information that is considered reasonable for the security and integrity of the *KNTS*. The *SO shall* communicate network information as requested to the *User*, as required for safe and reliable operation. The information exchange shall be electronic and/or paper-based, and within the time frame agreed upon between the *Users*.

(b) The *Users* shall optimise redundant control centre facilities where required for the safe operation and control of the *KNTS*.

(c) The Users may share as they agree network informantion and access that is considered reasonable for the security and intergrity of the KNTS.

20.4.6 Communication Facilities Requirements

(a) The minimum communication facilities for voice and data that are to be installed and maintained between the *SO* and *Users* shall comply with the applicable standards of KEBs or internataional standards approved by KEBs for supervisory control and data acquisition (*SCADA*) and communications equipment.

(b) The communication facilities standards shall be set and documented by the *SO* acting reasonably, in advance of design. Any changes to communication facility standards impacting on *User* equipment shall be designed in consultation with *Users* and shall be informed by a reasonable business motivation.

(c) Users shall ensure the communication facilities are available at all times and continoulsy attended to and there is adequate redundancy.

20.4.6.1 Telecontrol

(a) The *User*'s plant shall support data acquisition to and from the plant gateway. The *SO* shall be able to monitor the state of the *KNTS* via telemetry from the gateway connected to the *User*'s plant.

(b) The signals and indications required by the *SO* shall be agreed between the *SO*and the *User*, together with such other information as the *SO* may from time to time reasonably require by notice to the *User*.

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

(d) *Users* shall comply with such telecontrol requirements as may be applicable to the primary control centre and, as reasonably required, to the emergency control centre of the *SO*. Any changes to telecontrol requirements impacting on *User* equipment shall be designed in consultation with *Users* and shall be informed by a reasonable business motivation.

20.4.6.2 Telephone

(a) Each *User* shall be responsible for the provision and maintenance of no fewer than one telephoneline that shall be reserved for operational purposes only, and shall be continuously attended to and answered without undue delay.

(b) The *SO and Users* shall use a voice recorder for historical recording of all operational voice communication. 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 *User* and/or the *Authority*.

20.4.6.3 Electronic Mail

The *Users* shall provide the *SO*with the electronic mailing address of the contact person as defined in this Information Exchange Chapter and vice versa. The provider of this service shall be selected to meet the real-time operational requirements of the *SO*.

20.4.7 SCADA and Communication Infrastructure at Points of Supply

20.4.7.1 Access and Security

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

(b) Each *User* 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 chapter to third-parties, and shall disclose that person's name and contact details to the *Authority*. A *Party* may, at its sole discretion, designate more than one person to perform these duties.

(c) New licensees shall endeavour to be visible to the SO SCADA prior to hot commissioning.

20.4.7.2 Time Standards

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.

20.4.7.3 Integrity of Installation

Where the *Electrical Plant* does not belong to the *TNSP* and/or *SO*, the *TNSP* and/or *SO*shall enter into an agreement with the *User* for the provision of reliable and secure facilities for the housing and operation of *TNSP* and/or *SO*equipment. This includes access to, at no charge to the *TNSP* and/or *SO*, an uninterruptible power supply with an eight (8) hour standby capacity.

20.4.8 Data Storage and Archiving

(a) The obligation for data storage and archiving shall lie with the information owner.

(b) The systems that store the data and/or information to be used by the parties shall be of their own choice and for their own cost.

(c) 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 parties.

(d) 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 its original state. The information shall be retained for a period of at least six (6) years (unless otherwise specified in the *KNTGC*) commencing from the date the information was created.

(e) Parties 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.

(f) Parties shall store *Outage* planning information electronically for at least six (6) years. Other system planning information shall be retained for the life of the plant or equipment concerned, whichever is the longer.

(g) The *SO*shall archive operational information, in a historical repository sized for six (6) years' data. This data includes:

  (i) *KNTS* time-tagged status information, change of state alarms, and event messages

  (ii) Hourly scheduling and energy accounting information

  (iii) Operator entered data and actions.

(h) 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.

20.5 POST-DISPATCH INFORMATION

20.5.1 System and Generating Plant Information

The *SO* shall provide applicable *Users* the following information:

(a) Hourly system total MW loading

(b) Hourly individual *Generating Plant* MW sent out
(c) Hourly system constraints and constrained generation
(d) Hourly international tie-line power flow
(e) Predetermined system load flow data

20.5.1.1 Additional Unit Post-dispatch Information

(a) The *SO and Generation licensee* shall provide the following operational information regarding unit dispatch:

(i) Unit high limit, MW
(ii) Unit low limit, MW
(iii) Unit *Automatic Generation Control* (*AGC*) mode
(iv) Unit *AGC* status, Automatic/Off/Manual
(v) Unit set-point, MW
(vi) *AGC* pulse
(vii) Unit sent out, MW
(viii) Unit auxiliary, MW
(ix) Unit contract, MW
(x) Unit spinning, MW
(xi) 32-bit flag on *AGC* setting, 32 bits

(b) The *SO* shall provide operational information regarding overall dispatch performance:

(i) *Area Control Error* (*ACE*), MW
(ii) Average *ACE* previous hour, MW
(iii) System frequency, HZ
(iv) Frequency distribution current hour, HZ
(v) Frequency distribution previous hour, HZ
(vi) System total generation, MW
(vii) Control area total actual interchange, MW
(viii) Control area total scheduled interchange, MW
(ix) System operating reserve, MW
(x) System sent out, MW
(xi) System spinning reserve, MW
(xii) *Automatic Generation Control (AGC)* regulating up, MW
(xiii) *AGC* regulating down, MW
(xiv) *AGC* regulating up assist, MW
(xv) *AGC* regulating down assist, MW
(xvi) *AGC* regulating up emergency, MW
(xvii) *AGC* regulating down emergency, MW
(xviii) *AGC* mode
(xix) *AGC* status, On/Off
(xx) *Area Control Error* output, MW
(xxi) System transmission losses, MW
(xxii) tie-lines, MW
(xxiii) *AGC* performance indicators

20.5.1.2 Hourly Demand Metering Data

SO shall provide *Users* with hourly-metered data pertaining to their installations on need basis. This same information may be shared with the Authority.

20.5.2 File Transfers

(a) 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 parties involved.

(b) The parties shall keep the agreed number of files for backup purposes so as to enable the recovery of information in the case of communication failures.

Table 20-3: File Transfers

File	Description	Trigger Event	Frequency
AGC pulses	The total pulses sent to a unit by the *AGC* system to move the set-point up or down	Ongoing, file created at end of hour	Hourly
System near real-time data	Historical near real-time system data files on readings as required for post-dispatch	Communication failure	To be agreed
Unit near real-time data	Historical near real-time unit data files on readings as required for post-dispatch	Communication failure	To be agreed

20.5.3 Performance Data

20.5.3.1 Generating Plant Performance Data

(a) *Generation Licensee*s shall provide the *SO and Authority* monthly with performance indicators for each unit at each *Generating Plant* including those indicators listed below, and others as agreed between the *SO and Authority* and the *Generation Licensee*s.

  (i) Capacity factor
  (ii) Equivalent availability factor
  (iii) Equivalent forced *Outage* rate
  (iv) Equivalent planned *Outage* hours
  (v) Start-up time
  (vi) Successful start-up ratio

(b) *Generation Licensee*s shall report significant events, such as catastrophic failures, to the *Authority* within one (1) week of occurrence of such event.

20.5.3.2 Distribution Licensee and End-user Performance

(a) The performance measurement of all *Distribution Licensees* and *End-users* shall be supplied to the *Authority*.

(b) The Parties shall negotiate and agree on the details of acceptable levels of performance for *Distribution Licensee* or *End-user* networks. Acceptable network performance principles shall include:

  (i) Performance comparable with benchmarks for similar networks
  (ii) Performance within the design or original equipment manufacturer (OEM) specifications of the *User* and transmission equipment
  (iii) Performance at the *Connection Point* that complies with the *TNSP* operating procedures

(iv) Performance consistent with the outcomes of the investment criteria

(v) Performance that does not negatively impact on agreed levels of performance with other *Users*.

(c) If the Distribution *Licensee* or *End-user* network performance falls below acceptable levels and affects the quality of supply to other *Users* or causes damage (direct or indirect) to the *TNSP* equipment, the process for dispute resolution as described in Section 3.11 shall be followed.

(d) The *Authority* shall determine criteria for the contracting of acceptable levels of performance.

(e) If *Distribution Licensees* or *End-users* 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, e.g. by improving their line maintenance practices, improving protection and breaker operating times, if necessary replacing the said equipment, installing additional network breakers, changing operating procedures, installing fault-limiting devices if the number of faults cannot be reduced, etc. These changes to their networks should be effected in consultation with the *TNSP* and the *SO* regarding both the technical scope and the time frame.

(f) Where *Quality of Service (QOS)* standards are not met, the parties shall co-operate and agree in accordance with *Authority* power quality directives in determining the root causes and plans of action.

(g) Distribution *Licensees* shall report periodic testing of under-frequency and under-voltage load shedding relays in the following format:

Table 20-4: Periodic Testing

Distribution Licensee:…………………….

Date:……………………………………………

Substation:…………………………………..

Fed from transmission substation (directly or indirectly):…………………………………..

	Activating Frequency/Voltage		Timer Setting	
	Required	As tested	Required	As tested
Stage 1				
Stage 2				
Stage 3				
Stage 4				
	Feeders Selected (required)		Feeders Selected (as tested)	
Stage 1				
Stage 2				
Stage 3				
Stage 4				

20.5.3.3 TNSP and SO Performance

(a) The *TNSP*s and the *SO* shall make the following *KNTS* performance indicators available monthly to the *Authority* and *Users*:

Table 20-5: Performance Indicators

Indicator	Month	Year to date	12 Month Moving Index	Unit
System minutes lost				Minutes
Number of interruptions				
Number of statutory voltage transgressions				
Mandatory under-frequency load shedding				
User voluntary load shedding				
SAIDI (System Average Interruption Duration Index)				
SAIFI (System Average Interruption Frequency Index)				
CAIDI (Customer Average Interruption Duration Index)				Time
KNTS losses				%

(b) *TNSP*s shall provide *Users* with all performance indicators at each point of supply.

20.5.3.4 System Operational Performance Information

(a) The following *KNTS* operational information shall be provided to the Authority by SO:

- (i) Daily:
  1. The hourly actual demands of the previous day (MW)
  2. The reserve amounts over the morning and evening peaks of the previous day (MW)
- (ii) Monthly:
  1. MW generated, imports, exports, available for distribution/sale and transmission losses.
  2. Generation Plant availability
  3. Regulating reserve Hours deficit over total hours
  4. Number of frequency excursions > 50.5 or <49.5
  5. For each abnormal network condition, the action taken by the *SO*to restore normal operations.
  6. Network constraints
- (iii) Annually:
  1. Annual peak (MW), date and hour
  2. Annual minimum (MW), date and hour

(b) The TNSP 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 *Users* on request.

20.5.4 Guaranteed Performance Indicators

20.5.4.1 Guaranteed Performance Standards for the System Operator

The System Operator shall be subject to the following Guaranteed Performance Standards:

(a) The grid frequency shall be maintained within the limits set out below:

(i) Under normal operation, the Frequency of the national grid shall be nominally 50Hz and shall be controlled between 49.5Hz and 50.5Hz (±1%), unless exceptional circumstances prevail.
(ii) Following a system disturbance such as a load variation, the Frequency band shall be extended to 49.0–51.0Hz (±2%).
(iii) If a major Generating Unit is tripped, a major transmission element fails or large loads are suddenly disconnected, the maximum Frequency band becomes 48.75 –51.25Hz (±2.5%).
(iv) If several of the contingencies mentioned in (c) above occur simultaneously, the operating condition shall be labelled as extreme and the frequency can be below 47.5 Hz or above 51.5 Hz (-5%/+3%) for up to 20 seconds, and then extreme measures should be taken to restore the system.

(b) The voltages at the transmission network nodes shall be maintained within the limits set out below:
(i) Under steady state normal conditions, the voltage limits shall be 0.95 to 1.05 pu.
(ii) After any single contingency, the voltage limits shall be 0.90 to 1.10 pu.
(iii) After any multiple Contingency or severe system stress, the voltage limit shall be 0.85 to 1.20 pu.

20.5.4.2 Guaranteed Performance Standards for Generation Licensee

The Generation Licensee shall be subject to the following Guaranteed Performance Standards:

(a) For grid stability purposes, the generation licensees for conventional generators shall ensure that the generating units are designed to provide continuous operation when the Frequency changes within the Frequency Range of 47.50 Hertz and 51.50 Hertz.

(b) For variable renewable power plant, the frequency Limits shall be as indicated in Table 20-6.

Table 20-6: Frequency Limits

Frequency Limits	Duration
49.50 Hz to 50.50 Hz	Continuous operation (normal)
49.00 Hz ≤ f < 49.50 Hz or 50.50 Hz Hz < f ≤ 51.00 Hz	For duration of at least 60 minutes
48.00 Hz ≤ f < 49.50 Hz or 50.50 Hz < f ≤ 51.50 Hz	For duration of at least 30 minutes
47.50 Hz ≤ f < 49.50 Hz or 50.50 Hz < f ≤ 51.50 Hz	For duration of at least 3 minutes
<47.50 Hz or >51.50 Hz	For duration of at least 20 seconds
<47.00 Hz for more than 0.2 sec	May disconnect
>52.00 for more than 4 sec	Must disconnect

(c) The Licensee shall design and operate its generation plant in a manner that enables the System Operator to maintain the system frequency within the limits of 49.50 Hz and 50.50 Hz during normal conditions.

(d) The generation Licensee shall provide constant terminal voltage of the Generating Unit without instability over the entire operating range of the Generating Unit. The Generator automatic voltage regulator shall be capable of maintaining terminal voltage to an accuracy of ±0.50% relative to the constant reference value adjustable over the range of ±5% to ensure adequate steady state stability.

(e) Conventional Generating Unit shall be capable of supplying rated power output (MW) at any point between the limits 0.85 power factor lagging and 0.95 power factor leading at the *Generating Unit* terminals.

(f) For variable renewable power plant the power factor shall be as indicated in Table 20-7.

Table 20-7: Power Factor Limits

Voltage, p.u.	*Reactive Power*Range (p.u. of full output)	Equivalent Full Load Power Factor
0.20 to 0.80	-0.330 to 0.330	-0.950 to 0.950
0.80 to 1.10	-0.228 to 0.228	-0.975 to 0.975

(g) The generation licensee shall comply with the technical requirements stipulated in the power purchase agreement, such as plant availability, provision of ancillary services and black start.

20.5.4.3 Guaranteed Performance Standards for Transmission Licensee

The Transmission Licensee shall be subject to the following Guaranteed Performance Standards

(a) Allowable voltage deviations under normal conditions shall be ±5% and under single contingency shall be ±10%.

(b) The Voltage Flicker on the transmission network as measured at the Connection Point shall not exceed:

(i) ± 1% of the Steady State voltage level, when these occur repetitively; or

(ii) ± 3% of the Steady State voltage level, when these occur infrequently.

(c) For the purpose of these regulations, repetitively and infrequently shall mean the tolerable levels for harmonic voltage in the transmission network, as a percent of the nominal voltage, shall comply with the level indicated in Table 20-8.

Table 20-8: Tolerable levels for harmonic voltage

Voltage Level	Individual Harmonic Distortion Limits	Total Harmonic Distortion Limits
HVDC	Equivalent disturbing current of 2.5Amp on the DC side	
220 kV and above	1%	1.5%
132 kV	1.5%	2.5%
66 kV	3%	5%

(d) The Transmission Licensee shall achieve the transmission network reliability indicators indicated in Table 20-9

Table 20-9: Transmission network reliability indicators

Performance Indicator		Value		
		Baseline	Target year 1-5	Target year 6 and above
Average annual number of forced interruption for all transmission lines *(The total number of sustained interruptions for every 100km per line)*	HVDC	3.0	2.5	2.0
	400 kV	3.0	2.5	2.0
	220 kV	3.0	2.5	2.0
	132 kV	6.0	5.5	5.0
	66 kV	55.0	52.0	50.0
Average duration of forced interruption (ADFI) *[This excludes force majeure and third party interferences.]*	HVDC		0.50	0.40
	400 kV	0.6	0.50	0.40
	220kV	0.6	0.55	0.45
	132 kV	0.6	0.55	0.50
Transmission network Annual Availability	400 kV		96.0%	97%
	& 220kV	95%	96.0%	97%
	132 kV	95%	95.5%	96%

(e) The Transmission Licensee shall comply with the technical requirements stipulated in the Network Service Contract/Operation and Maintenance Contract.

(f) The Transmission Licensee shall achieve an efficient level of Transmission Losses (both technical and commercial Losses) on his own system. The standard level of Transmission Losses shall be established by the Authority within the tariff review structure.

21 CYBER SECURITY

Cyber Security is the protection required to ensure confidentiality, integrity, and availability of the electronic communication system. With the two-way flow of electricity and information, the management and protection of the electrical communication system that includes information technology and telecommunication infrastructure, has become critical to the electric utility industry.

21.1 INTRODUCTION

With the increase in dependence on modern communication technology (e.g., wireless, cloud computing, etc.), power systems are vulnerable to cyber-attacks and hackers. In Kenya, the growth in the field of information, communication, and technology (ICT) makes it imperative to develop a sound Cyber Security strategy that will ensure confidentiality, integrity, and availability of public and private sector information across Kenya's ICT infrastructure.

Kenya's strategy for Cyber Security includes:

(a) Enhancing the Cyber Security posture to facilitate the country's growth, safety, and prosperity.

(b) Fostering Cyber Security awareness and developing Kenya's workforce to ultimately build national capability.

(c) Facilitating information sharing and collaboration among relevant stakeholders while staying information focused.

(d) Defining the national Cyber Security vision, goals, and objectives and coordinating Cyber Security initiatives at the national level in line with Kenya's Cyber Security strategy, goals, and objectives.

Following the guidelines and best practices as described by the US Department of Energy, National Institute of Standard and Technology (NIST – under US Department of Commerce), and National Rural Electric Cooperative Association (NRECA, from US), and some observations of Cyber Security best practices in India and Europe, this document provides guidance for developing Cyber Security controls that would help meet the potential security challenges for Kenya's power grid modernisation.

This chapter addresses:

(a) development of information security management controls and procedures;
(b) development of Cyber Security systems with identity;
(c) access management systems; and
(d) building defence against threats through training, awareness and monitoring.

21.2 OBJECTIVES

The key objectivesshall be as follows: .

(a) Protect Critical Information Infrastructure
(b) Awareness and Training: Inform and educate
(c) Communications and Outreach: Elevate Cyber Security awareness for government, private sector, and the Kenyan public.
(d) Develop a comprehensive governance framework to leverage resources, reduce conflict and duplication of effort, and work toward Kenya's long-term Cyber Security goals.
(e) Implementation of the National Cyber security Strategy and Master Plan.

21.3 SCOPE

The following issues are considered and detailed in the scope of Cyber Security in this document:

(a) People and policy
(b) Operational issues
(c) Insecure software development life cycle (SDLC) risks
(d) Physical security
(e) Third-party relationship
(f) Network security
(g) Platform security
(h) Application security

21.3.1 People and Policy

Policies and procedures are the final protective or mitigating control against security breaches, and hence shall be examined closely to ensure its consistency with both the inherent business objectives and secure operations. Policies and procedures shall be well documented to ensure there is no deficiency that can lead to any security risks for the organisation.

21.3.1.1 Security Policy

Security policies shall be well structured in a practical, flexible, and easy to understand manner. Implementation and enforcement of the policies (e.g., through audits and disciplinary actions for noncompliance) shall be monitored periodically. Adequate flexibility shall be in place so improvements and modifications shall be made easily as needed. At leaset every 2 years, the policies must be reviewed and approved by the designated authorities within the organisation.

21.3.1.2 Security Policy Elements

The security policies must address the following elements:

(a) **Policy Management:** this shall address purpose, scope, and applicability, roles and responsibilities; implementation and enforcement procedures; exceptions, and policy reviews; approvals, and change management;
(b) **Personnel and Training:** personnel risk assessment, security awareness program, and Cyber Security training shall all be under the umbrella of this key element.
(c) **Critical Asset Management:** methodology for identifying critical cyber assets; inventory and classification of cyber assets, information protection and data privacy; cyber vulnerability assessment, access control, monitoring, and logging; disposal or redeployment of assets; maintenance and change control of the asset inventory and classifications;
(d) **Electronic Security Perimeter (ESP):** critical assets within the perimeter; cyber vulnerability assessment; access control/monitoring and logging, Configuration, maintenance, and testing; documentation maintenance to support compliance.

21.3.1.3 Security Related Roles and Responsibilities

Roles of people responsible for maintaining security shall be defined and documented. These roles shall include:

(a) The governing body for the security policy (e.g., an oversight board comprising representatives of stakeholder groups).
(b) A designated information security manager who maintains the policy and provides guidance for implementation, training, and enforcement.
(c) Department managers who “own” the critical cyber assets and are responsible for implementing the security policies and procedures to protect those assets.
(d) Personnel with authorised access to critical assets who must review, provide feedback on, and comply with security policies.

21.3.1.4 Privacy Policy

Insufficient privacy policies can lead to unwanted exposure of employee or *Customer*/client personal information, resulting in both business and security risks. A privacy policy, that documents the necessity of protecting private/personal information to help ensure that data is not exposed or shared unnecessarily, shall be established.

21.3.1.5 Policy Exception

Reasons such as an overriding business need, a delay in vendor deliverables, new regulatory or statutory requirements, and temporary configuration issues may necessitate policy exceptions. The exception process must ensure that these circumstances are addressed in a manner to make all stakeholders aware of the event, the risks, and the timeline for eliminating the exception.

21.3.1.6 Personnel and Training

Training is required for everyone in the organisation to get a clear understanding of the importance of Cyber Security. All employees shall acquire a level of security awareness training (with roles and responsibilities clearly defined), the degree of which shall vary based on the technical responsibilities and/or the critical assets one is responsible for.

Workshops shall be arranged periodically to provide training in such areas as Cyber Security for Critical Infrastructure, Threats and Attacks, Cyber Security Framework and Communications, Network and Information Security, Building Cyber Attack Resilience, Cyber Security Audit and Assessment, and Cyber Security Assessment Project. Such workshops shall be aimed at providing exposure to the local utilities (*Generation, Transmission*, and *Distribution*), local Academia and R&D organisations as well as industry experts from overseas sharing with the best practices knowledge and experience.

21.3.1.7 Due Diligence in Hiring

Diligence in the hiring and personnel review process is crucial. It is important to define and document a risk assessment program for personnel with authorised cyber access or authorised unescorted physical access to critical cyber assets. The program must comply with applicable laws and existing collective bargaining agreements. The risk assessment must include, at a minimum, identity verification and criminal check. This information must be updated periodically at a frequency as determined by the local regulatory authorities. Similar checks must be enforced for the employees of third-party vendors.

21.3.1.8 Access Privileges

System access and information shall be granted only on an as-needed basis. System access needs to be managed, monitored, and enforced based on the individual’s access requirements and the level of impact that uncontrolled access could have on the organisation. In general, each employee shall be granted the lowest levels of access to cyber assets and other privileges needed to do his or her job efficiently. A list of all personnel with authorised cyber access or authorised unescorted physical access to critical cyber assets shall be maintained. This list that contains each person's specific electronic and physical access rights to such assets shall be reviewed quarterly and updated within seven (7) days of any change in a list member's access rights.

21.3.1.9 Identity Validation, Background Checks

Identity validation/background checks shall be implemented based on an individual's area of responsibility, the physical facilities/hardware/systems, and the type of information authorised to access. The more sensitive information available to an individual, the deeper and more detailed the identity validation and background check process needs to be.

21.3.2 Operational Security

Operational mistakes can break security policies. Although operational mistakes cannot be completely avoided, it is possible to reduce the risk of a mistake. Operational security acts as a deterrent against mistakes and deliberate misconfigurations. The ability to detect a mistake and trace it back to its source could also deter insiders from making malicious misconfigurations or to help quickly detect operator mistakes. The operational security shall deal with the responsibilities and authorisation, as well as disciplinary actions in case of breaches. Industry compliance regulations require certain operational security measures. Network operators should check which regulation applies and verify that the required measures are in place.

It is often possible to provide additional security measures that are not fully dependent on operational mistakes. However, before implementing additional security measures a formal risk assessment needs to be performed to balance the cost of the additional measures with the cost of the risk incurred due to operational weaknesses. A Cyber Security program must be comprehensive — it is only as strong as its weakest link. Failure to develop appropriate controls in any category provides openings for attackers. This guide includes sections that describe common risks and mitigations in each category.

21.3.2.1 Risk Assessment and Mitigation

Security risks are fundamentally caused by people/policies/process/technology. An important part of the risk management process is to determine the severity of each risk as a function of its impact and likelihood. It is also important to understand the extent to which existing security controls completely or partially mitigate each risk. It is then possible to enumerate the gaps in protection and make an informed risk-based decision on next steps.

Although a risk management strategy strives for risk prevention where practical, it also must balance the costs and benefits of security controls.

21.3.2.2 Access Control, Monitoring, and Logging

Access control that includes both technical and procedural control (e.g., logs, user account review, account management, restricting use of shared accounts, password use), enforces the authentication and accountability of all user activities. Access control requires not granting *users* access to network resources, before they are authenticated and authorised using their own individual (i.e., non-shared) credentials. Remote access to networks shall be limited to an absolute minimum. When required, technologies like Virtual Private Networks (VPNs, IPSec) shall be used to create a secure tunnel after properly authenticating the connecting *Party* using their individual credentials. In addition to user name and password, also use an *RSA ID*-like device to provide an additional factor of authentication. Access control shall be implemented for critical cyber assets by restricting authorised users and transactions. A designated security team shall be in charge of access control and system logs. Access control shall be enhanced through perimeter security (e.g., security personnel, surveillance cameras and fences) wherever possible. Use an access control model whose default setting is to deny access, thereby requiring explicit permission changes to enable access. Similarly, for all access points enable only the ports and services required for approved operations and monitoring. Remote interactive access to a point within the perimeter typically must be accompanied by strong procedural or technical controls to enforce authentication of the authorised users. The Network access level that is needed for each individual or role at the organisation shall be documented and only the required level of access shall be granted to these individuals or roles. All exceptions shall be noted.

All cyber assets, where technically feasible, shall include automated tools or organisational process controls to monitor Cyber Security-related system events. All automated mechanisms or processes shall be documented. The monitoring function shall log each detected Cyber Security incident and issue an alert. All such events shall be reviewed and logged. Logs shall be maintained for at least ninety (90) days.

21.3.2.3 Disposal or Redeployment of Assets

Formal methods, processes, and procedures for disposal or redeployment of cyber assets that are within an Electronic Security Perimeter (ESP) shall be documented and implemented in order to prevent any accidental release of sensitive and confidential information. Disposal of any cyber security assets should conform to applicable laws. This shall include, at a minimum, destroying or erasing the data storage media and maintaining records of asset disposition.

21.3.2.4 Change Control

Managing change is essential to maintaining a robust ongoing security posture. The state of the hardware, operating system must be monitored. Change control mechanism shall ensure that new cyber assets and significant changes to existing cyber assets shall not adversely impact existing Cyber Security controls or the overall security posture of the system. Change management processes shall also ensure an uninterrupted operation of the system. All changes shall be logged and executed in a controlled way. The logs must be evaluated and checked for potential misconfigurations. The logs shall also be used to demonstrate a deliberate breach of the operational security policy.

21.3.2.5 Patch Management Process

A patch management process must be in place to ensure that software and firmware are kept current to remediate against known vulnerabilities, or that a proper risk analysis and mitigation process is in place when patches cannot be promptly installed. Evaluation, installation, testing, and tracking process of Cyber Security patches, cumulative service packs, and version upgrades shall be implemented and documented.

21.3.2.6 Vulnerability Assessments

Cyber vulnerability is a gap or weakness in a system's security controls that a threat can exploit. Vulnerability assessments are necessary for generating awareness of threats, attacks, vulnerabilities, and ensuring the effectiveness of existing controls. They also establish baselines that future assessments can use to determine the need and effectiveness of planned improvement. A cyber threat is any entity or circumstance that has the potential to harm an information system along with its mission and goals.

Cyber vulnerability assessment of the access points to each ESP shall be done at least once a year to examine ways in which the security perimeter can be breached and existing security controls bypassed to compromise confidentiality, integrity, or availability of critical cyber assets.

21.3.2.7 Configuration Management and Maintenance

Improperly configured software/systems/devices added to existing software/systems/devices can lead to insecure configurations and increased risk of vulnerability. Configuration management processes must be in place to ensure that system configurations are governed appropriately in order to maximise overall system reliability.

A designated network team shall execute the configuration actions. Typical actions such as:

(a) adding vulnerable hardware;
(b) introducing tampered device to the system;
(c) failure to document changes made to the network configuration;
(d) not having a sign-off approval in the configuration management process; and
(e) changing network configuration that reduces security profile

shall be in the realm of responsibilities of the network team.

21.3.2.8 Incident Management and Handling

An incident such as a breach of security or reliability protections can potentially cause loss of confidentiality, integrity, or availability of data, maintenance, and sustainment of any software or hardware product or operations. System reliability depends on the ability of participant organisations to quickly detect, report, and respond to incidents. Problems detected and correctly handled in a timely manner can prevent them from spreading to other entities. Knowledge gained from detecting and responding to computer security incidents provides insight into real risks and threats to the integrity, confidentiality, and availability of software and hardware products

A robust incident-handling capability requires planning, documented procedures, and ongoing training and rehearsal for all personnel who might be required to report, analyse, or respond to incidents. This capability begins with a clear policy statement of incident- handling requirements.

21.3.2.9 Contingency Planning

Contingency planning shall include policy, plans, and procedures for disaster recovery and continuity of operations. Policy and plans must include preparation and training for responding to an emergency along with detailed procedures for executing defined strategies.

A disaster recovery plan applies to a major disruption to service that deny access to the primary facility infrastructure for an extended period of time. It includes the preparation (e.g., off-site storage of system backups), emergency facilities, and procedures for restoring critical cyber assets and infrastructure at an alternate site after an emergency.

A business continuity plan focuses on sustaining an organisation's mission and business functions during and after a disruption. A business continuity plan shall be written for mission/business functions within a single business unit or it may address the entire organisation's processes.

Continuity and recovery plans also define interim measures that increase the speed with which organisations resume service after disruptions. These plans must be tailored to each system. Creating specific measures requires a detailed understanding of specific scenarios.

Some of the key items that need to be addressed in the contingency plan are:

(a) Server backup and recovery;
(b) Data backup and recovery;
(c) Network backup and recovery; and
(d) Employee backup

21.3.2.10 Software Development Life Cycle (SDLC)

The software development shall have the objective to design, implement, configure, and support software systems to enable:

(a) Continuous operation even under most attacks by either restricting the exploitation of faults or other weakness in the software by the attacker, or tolerating the errors and failures that result from such exploits;
(b) Isolation and containment of damage caused by any failures from attack-triggered faults that the software was unable to resist or tolerate, and
(c) Recovery from fault conditions as quickly as possible

Information gathered from incident handling shall be used at the beginning of the SDLC to help define better security requirements in products and provide a better understanding of the threat environment within which these products must operate. Knowledge gained from containing and mitigating computer security risks and threats shall also help identify auditing and recovery requirements for systems and software. Such requirements include:

(a) building alerts when files and components that should not be changing are modified,
(b) establishing policy and configuration setting capabilities to identify and control specific software and hardware components that should not be changed during normal operations, and
(c) providing functionality for logging unauthorised changes or malicious attacks in a manner that would preserve evidence in a forensically sound manner.

Collection and sharing of information shall be smooth and successful if there is a well-defined and structured relationship between the software system developers and incident management staff. Practices in SDLC shall include:

(a) Developing abuse cases to help refine requirements and build business cases
(b) Performing business risk analysis
(c) Implementing test planning (e.g.,security functionality and risk-driven testing)
(d) Performing code review
(e) Performing penetration testing
(f) Deploying and operating applications in a secure environment

21.3.3 Physical and Logical Security

Physical security is the protection of personnel, hardware, programs, networks, and data from physical circumstances and events that could cause serious losses or damage to an enterprise, agency, or institution. This includes protection from fire, natural disasters, burglary, theft, vandalism, and terrorism. A physical security plan, sponsored by senior management in the organisation, must be documented, implemented, and maintained. The plan shall address the following among other things:

(a) The protection of all cyber assets within an identified physical security perimeter or by way of alternate measures if a completely enclosed border is not feasible.

(b) The identification of all physical access points past the physical security perimeter and measures to control entry at those access points to make network links harder to compromise.

(c) Processes, tools, and procedures to monitor physical access to the perimeter(s).

(d) Appropriate use of physical access controls.

(e) Review of access authorisation requests and revocation of access authorisation.

(f) A visitor control program for personnel without authorised unescorted access to a physical security perimeter.

(g) Physical protection from unauthorised access and a location within an identified physical security perimeter for cyber assets that authorise or log access or monitor access to a physical or electronic security perimeter.

(h) Documentation and implementation of operational and procedural control to manage physical access at all access points at all times.

(i) Ensuring that all ports and services not required for normal and emergency operations are disabled.

(j) Use of antivirus and malicious software prevention tools, where technically feasible.

(k) Enforcement of restrictions on who can perform maintenance and repair, emergency procedures, and remote configuration and maintenance

Physical security shall be implemented in the following levels:

(a) Multiple locks, fencing, walls, fireproof safes, and water sprinklers shall be placed in the way of potential attackers and sites shall be hardened against accidents and environmental disasters.

(b) Surveillance and notification systems (such as lighting, heat sensors, smoke detectors, intrusion detectors, alarms, and camera) shall be put in place as an alert.

21.3.3.1 Monitoring, Logging, and Retention

The organisation must document and implement the technical and procedural controls for monitoring physical security system at all access points at all times. Unauthorised access attempts must be reviewed immediately and handled in accordance with procedures. Logging will be sufficient to uniquely identify individuals and the time of access. Physical access logs should be retained for at least ninety (90) calendar days.

Routinely review network logs for anomalous/malicious behaviour via automated and manual techniques.

21.3.3.2 Maintenance and Testing

Each physical security system must be tested at least once every three (3) years to ensure it operates correctly. Testing and maintenance records must be maintained at least until the next testing cycle. *Outage* records must be retained for at least one (1) calendar year.

21.3.3.3 Third-party Relationship

Third-party vendors provide a wide variety of products and services. If these vendors are not exercising reasonable care in preparing for and responding to Cyber Security threats, incidents may occur that could have serious consequence. In order to mitigate such situations, the third-party vendor shall be required to have a signed contract for such Cyber Security protections as:

(a) performing regular malware scans,
(b) patching vulnerable systems in a timely manner, and
(c) enforcing a strong password policy.

Vendors shall provide notification of known vulnerabilities affecting vendor-supplied, application, and third-party software within a pre-negotiated period after public disclosure.

Vendors shall verify and provide documentation that all services are patched to current status. Vendors shall provide a configurable account password management system that allows for selection of password length, frequency of change, setting of required password complexity, number of login attempts, inactive session logout, screen lock by application, and denial of repeated or recycled use of the same password.

In the case of pre-existing contracts and relationships, it is crucial first to perform a full audit of these previous contracts to determine whether Cyber Security gaps exist, and then to determine how best to fill any gaps through contract renegotiation with the vendor. Vendors shall provide details on their patch management and update process.

21.3.4 Network Security

Network Security is the protection of all data that leaves or enters the local computer or server from the network. Controlled by a network administrator, network security involves the authorisation of access to data in a network, and preventing and monitoring unauthorised access, misuse, modification, or denial of a computer network and network-accessible resources. Refer to Section 21.3.2.2,"Access Control, Monitoring, and Logging" for more on Network Security and access control. Intrusion Detection Systems (IDSs) shall be used to detect any anomalous behaviour on network. If anomalous behaviour is encountered, the potentially compromised nodes on the network must be isolated from the rest of the network.

All settings used on network hardware shall be set to their secure settings. Settings provided by each piece of hardware must be fully understood. Do not assume that default settings are secure.

21.3.4.1 Network Connection Control

User assigned devices shall be restricted to connection to specified network segments only, and shall be uniquely identified and approved for use. Care shall be taken in granting authorised connections to network segments where information of a higher security classification is stored, processed, and/or transmitted and the user of that device has not been granted access to information assets of that classification. Source of network time shall be accurate and that accurate time shall be reflected on all network nodes for all actions taken and events logged.

User devices shall be prohibited from cross-connecting (i.e., acting as a router) between any two networks. Unneeded *network services* shall be disabled.

21.3.4.2 Firewall

Firewalls play an important role in establishing the first line of defence against cyber threats. Combined with anti-spyware, anti-virus and anti-spam software, strong passwords and safe online practices, a firewall adds a layer of protection that helps enhance Cyber Security. Firewalls protect the computer and information from:

(a) hackers breaking into the system;
(b) viruses and worms that spread across the Internet; and
(c) outgoing traffic from the host computer created by a virus infection.

Firewalls and virtual local area networks (VLANs) technologies shall be used to properly segment the network and to increase its compartmentalisation (e.g., machines with access to business services like e-mail should not be on the same network segment as *SCADA* machines). Firewall rules shall be routinely reviewed and tested to confirm expected behaviour.

Firewalls shall be configured in accordance with the organisation's standards and policies, and deny any of the following traffic types:

(a) Firewalls and other boundary security mechanisms that filter or act as a proxy for traffic from one network segment to another of a different security level.
(b) Invalid source or destination address (e.g., broadcast addresses, RFC 1918 address spaces on interfaces connected to public networks, addresses not assigned by IANA on interfaces connected to public networks).
(c) Those destined for the firewall itself, unless the firewall provides a specific service (e.g., application proxy, VPN).
(d) Source routing information.
(e) Directed broadcasts that are not for the subnet of the originator (these can be used to create broadcast storms in denial-of-service attacks against third-parties).
(f) Destined for internal addresses or services that have not been approved for access from external sources.

Requests for allowing additional services through a firewall or other boundary protection mechanisms must be approved by the information security manager.

21.3.4.3 Flow of Electronic Communications

Client systems shall communicate with internal servers. The internal servers shall communicate with the external systems via an intermediate system. The flow of traffic shall be enforced through boundary protection mechanisms.

Ensure channel security of critical communication links with technologies like Transport Layer Security (TLS). Where possible, implement Public Key Infrastructure (PKI) to support two-way mutual certificate-based authentication between nodes on the network.

Ensure that only standard, approved, and properly reviewed communication protocols are used on the network

21.3.4.4 Protecting Data in Transit

When any non-public classified data transits a network and the confidentiality and integrity of that data cannot be guaranteed because of the use of protocols which do not provide a mechanism for protecting the data payload, encryption shall be used to guard against disclosure and modification of the data.

Ensure availability, integrity, and confidentiality of data traversing the networks through use of digital fingerprints and signed hashes. If channel-level encryption is not possible, apply data-level encryption to protect the data traversing the network links. Time stamps to protect against replay attacks must be ensured. No actions should be taken based on the data coming from network nodes that may have been compromised.

Ensure that proper certificate and key management practices are in place. Remember that cryptography does not help if the encryption key is easy to compromise. Ensure that keys are changed periodically and that they are changed right away in the event of compromise.

21.3.4.5 Protecting Domain Name Service (DNS) Traffic

DNS provides a mechanism for resolving host names into Internet Protocol (IP) addresses in the internet. Due to its ability to map human memorable system names into computer network numerical addresses, its distributed nature, and its robustness, the DNS has evolved into a critical component of the Internet. Insecure underlying protocols and lack of authentication and integrity checking of the information within the DNS threaten the proper functionality of the DNS. The threats that surround the DNS are due in part to the lack of authenticity and integrity checking of the data held within the DNS and in part to other protocols that use host names as an access control mechanism. The DNS shall be deployed in a multitier architecture that protects internal systems from direct manipulation. Internal client resolvers shall direct their queries to internal DNS servers, which forward all queries for external resource records to DNS server(s). The flow of traffic shall be enforced through boundary protection mechanisms.

21.3.4.6 Network Routing Control /Use of Secure Routing Protocols or Static Routes

When exchanging routing information with external parties, secure routing protocols or static routes shall be used. If possible, network address translation shall be employed to prevent accidental leakage of internal routing information. Rules include:

(a) Users and devices shall not be allowed to specify the routing of network traffic. Development, test, and production environments shall be separated.

(b) Sufficient redundancy shall be ensured to exist in the network links so that rerouting traffic is possible if some links are compromised.

21.3.5 Platform Security Risks

Platform security risk focuses on the Operating Systems and other software making up the software stack on top of which an organisation's custom applications run. Each accessible host on an organisation's network is a potential target for attack. Adversaries will try to compromise these hosts via methods that cannot be mitigated through network security controls alone. It is imperative to ensure that the platform software running on the hosts is secure, including (but not limited to) operating system software, database software, Web server software, and application server software. Together these form a software stack on top of which an organisation's custom applications run.

21.3.6 Application Security

In-house developed or custom-procured application software must be developed with security in mind from the get-go to help ensure that it does not contain any software security weaknesses that may be exploited by adversaries to compromise the system. The software development process therefore must be security aware.

21.3.7 Unique Security Requirements and Controls

This section describes unique security best practices and controls needed for the grid modernisation and/or smart grid applications.

21.3.7.1 Advanced Metering Infrastructure (AMI)

The AMI network consists of various software & hardware components, and networks for communication. These include:

(a) "head end" operating on the utility network;
(b) wide area network (WAN) that provides communications from the utility head end out to the field;
(c) field access or collection points on the edge of the WAN providing connections and/or consolidation for metering data access, and
(d) mesh network known as a local area network (LAN) or neighbourhood area network (NAN) providing sub-networks of *Meters*, extending the reach to a larger Meter population. Home area networks (HAN) are also used to provide interfaces into the home to support customer awareness of energy consumption and to extend support for demand response functionality.

The security requirement for AMI begins with establishing fidelity of the meter data. Since smart *Meters* in the field are readily available, with few if any physical security controls, an attacker gaining physical access to the smart meter may "patch" their firmware, thereby compromising the smart meter. From this point on, any data supplied by the smart meter to the *SCADA* can no longer be trusted. If the attacker can repeat the same tactic on a broader scale, it may be possible for the hacker to generate incorrect actions for the *SCADA* system based on meter readings from compromised *Meters*. Detection of a compromised meter through remote attestation and other state-of-the art techniques is therefore of utmost importance.

It is important to note that an attacker need not gain physical access to many *Meters*. Since *Meters* are networked together, gaining access to one smart meter, downloading its firmware, reverse engineering the firmware to look for software vulnerabilities (e.g., buffer overflow), and then creating a root kit that can exploit that vulnerability to modify the functionality of the smart meter is all an attacker needs to do. A worm can then be used to propagate that root kit from one smart meter to another via a network that connects them. An attacker may then have a botnet of compromised smart meters that he or she can activate at any time to achieve the attack goal (e.g., cause a blackout).

(a) The following actions shall be taken in order to help mitigate this vulnerability: Verify with the software/hardware vendors (with embedded software) with proof of evidence (e.g., third-party assessment) that their software is secure and free of security weaknesses.
(b) Perform remote attestation of smart meters to ensure that the firmware has not been modified.

(c) Make use of communication protocol security extensions (e.g., MultiSpeak® security extensions) to ascertain the integrity, including the origin integrity, of smart meter data.
(d) Establish and maintain secure configuration management processes (e.g., when servicing field devices or updating their firmware).
(e) Ensure that all software (developed internally or procured from a third-party) is developed using security-aware SDLC.
(f) Apply a qualified third-party security penetration test to all hardware and software components prior to live deployment.
(g) Ensure that the software running on the smart meter is free of software weaknesses, especially if they are remotely exploitable. Otherwise, an attacker may be able take control of a user's smart meter to begin manipulating the climate in the user's home. When done on a large scale, this may result in blackouts.
(h) Implement physical security controls and detection mechanisms when tampering occurs.
(i) Ensure that a reliable source of network time is maintained.
(j) Disable the remote disconnect feature that allows electricity to be remotely shut down using a smart meter.

To safeguard end user privacy, smart meter information shall be decoupled from *Customer* information. Meter identification shall be done through a generic number instead of a specific household address, GPS location, etc.

21.3.7.2 Meter Data Management System (MDMS)

Data imported in to MDMS must be thoroughly validated for syntax and semantic for both privacy and data security issues. The following actions must be ensured:

(a) Data received by MDMS does not come from a compromised Meter.
(b) Data received by MDMS undergoes validation, estimation, and editing (VEE) protocols to ensure data integrity and completeness.
(c) Appropriate exception handling mechanism is available in place for compromised data.
(d) MDMS has been designed and implemented using security-aware SDLC.
(e) MDMS system has passed a security penetration test by a qualified third-party.
(f) Denial-of-service attempts (from compromised meters) are handled gracefully by MDMS.

21.3.7.3 Communication System

Communication system security has been covered under Network Securityin Section 21.3.4 of this chapter. Following is a list of actions important for the communication system security:

(a) Ensure data integrity
(b) Ensure origin integrity.
(c) Use proven communications protocols with built-in security capabilities.
(d) Ensure confidentiality of data where appropriate.
(e) Ensure proper network segmentation.
(f) Have a third-party perform network security penetration testing.
(g) Implement sufficient redundancy.

(h) Protect from man-in-the-middle attacks.
(i) Protect from replay attacks.
(j) Use proven encryption techniques.
(k) Use robust key management techniques.

21.3.7.4 Supervisory Control and Data Acquisition (SCADA)

SCADA system is a part of a utility's critical infrastructure and requires protection from a variety of threats that exist in cyber space. The following actions shall be taken to ensure Cyber Security of *SCADA* networks:

(a) Appoint a senior security manager with a clear mandate.
(b) Establish policies to minimise the likelihood of inadvertent disclosure of sensitive information regarding *SCADA* system design, operations, or security controls by organisational staff.
(c) Conduct personnel security awareness training.
(d) Clearly define Cyber Security roles, responsibilities, and authorities for managers, system administrators, and users.
(e) Apply basic network and system IT security practices (e.g., regular security patches, run antivirus software, etc.).
(f) Ensure that software running in the *SCADA* environment (e.g., either internal or external) has been built with security in mind and reviewed for security by a qualified third-party.
(g) Enforce the principle of least privilege when it comes to granting user access to *SCADA* resources.
(h) Conduct physical security surveys and assess all remote sites connected to the *SCADA* network to evaluate their security.
(i) Disconnect unnecessary connections to the *SCADA* networks.
(j) Document network architecture and identify systems that serve critical functions or contain sensitive information that need additional level of protection.
(k) Establish a rigorous ongoing risk management process.
(l) Conduct routine self-assessments.
(m) Establish system backups and disaster recovery plans.
(n) Test business continuity and disaster recovery plans.
(o) Establish *SCADA* "Red Teams" to identify and evaluate possible attack scenarios.
(p) Implement internal and external intrusion detection systems and establish 24-hours-a-day incident monitoring.
(q) Perform technical audits of *SCADA* devices, networks, and any other connected networks to identify security concerns.
(r) Perform monitoring and logging, and ensure that people are held accountable for their actions.
(s) Avoid taking critical control decisions without human confirmation.
(t) Avoid taking critical control decisions based on too few data points.
(u) Avoid taking critical control decisions based on data points from compromised field devices or based on data that has been tampered with.
(v) Ensure proper network segmentation in the *SCADA* environment.
(w) Ensure sufficient fault tolerance and redundancy in the *SCADA* environment.

(x) Use individual (rather than shared) user login accounts with strong passwords.

(y) Ensure that all hardware authentication settings have been changed from their default values.

21.3.7.5 In-Home Display (IHD)

IHD provides *Customer*s with information on energy consumption. The security of this device is critical from the customer's perspective in both preventing others from sneaking as well as preventing someone from using that device to manipulate household appliances. An attacker may be able take control of a user's IHD to begin manipulating the climate in the user's home. When done on a large scale, this may result in blackouts due to overloads. Attacks could be launched wirelessly through AMI network, communication channel, or the internet.

Additionally, if utilities and third-parties bundle internet access as a potential marketing hook, the device will also be subject to potential malware when a *Customer* surfs the internet. It is therefore imperative to have a mechanism for frequent security patches. The following actions shall be taken to ensure security of IHD:

(a) Ensure that the software running on IHDs is free of software weaknesses

(b) Ensure the integrity of data shown on the user's IHD.

(c) Ensure the integrity of data sent from the user's IHD to the control centre.

(d) Ensure the anonymity and privacy of data (where appropriate) pertaining to electricity usage patterns such that it cannot be tied back to the customer.

(e) Perform remote attestation of IHDs to alert the control centre when unauthorised firmware updates occur.

(f) Request third-party security penetration testing of IHDs

Tables 21-1 through 21-5 below provides at-a-glance summaries of risks, impacts, and mitigations for People and Policy Risks, Operational Risks, Thirds Party Risks, Network Risks, and Platform Risks.

Table 21-1: People and Policy Risk and Mitigation

Risk	Impact	Mitigations
Lack of security training and awareness.	Insufficiently trained personnel may inadvertently provide the visibility, knowledge, and opportunity to execute a successful attack.	All employees must undergo security training when hired and at least once a year thereafter. The degree and nature of security training for personnel shall vary based on their job function.
Inadequate technology & processes for identification / authentication	Online transaction and data/information privacy are vulnerable with identity fraud and theft	Identity proofing through appropriate background checks for all new hires must be done. Access to sensitive information and resources shall be given only after proper authentication and authorisation.

Risk	Impact	Mitigations
Inadequate security policy	Inadequate policies that do not drive operating requirements and procedures lead to vulnerabilities in Cyber Security.	Security policies must adequately cover all aspects of maintaining a secure environment.
Insufficient privacy policy	Undesirable exposure of employee/*Customer*/ client personal information could pose business and security risk.	Adequately defined privacy policies must cover all aspects of safeguarding access to private information.
Lack of management oversight for security.	Without sponsorship of senior management, it is not possible to successfully enforce a security program in the event of a policy compromised or abuse.	Assign a senior manager to be in charge of the overall security program who can make appropriate decisions in the event of the policies need to be modified.
Inconsistent action in revocation of employee access	Not revoking access of terminated employees could be a threat to Cyber Security that may lead to unauthorised access, and sabotage.	Employees shall have access to resources and systems only as needed to perform their job function for the duration as needed. All access for terminated employees shall be revoked before notifying them of termination.

Table 21-2: Operational Risks and Mitigation

Operational Risks	Potential Impact	Mitigation
Lack of patch management process.	Missing patches potential risks to the affected system.	Security patches shall be applied as appropriate, with automated alerts
Lax access control	Unauthorised users can obtain/modify/delete sensitive information	Periodically review the lists for each critical resource or system and the authorised users. Establish standards procedures and channels for granting and revoking employee access to resources or systems.
Inadequate change and configuration management.	Improperly configured software/systems/devices lead to insecure configurations and an increased risk of vulnerability.	All hardware and software must be configured securely. When unclear, seek further clarification from vendors as to secure settings and do not assume that shipped default settings are secure. Establish change management and approval processes for making changes to the configuration to ensure that the security posture is not jeopardised.

Operational Risks	Potential Impact	Mitigation
Lack of periodic security audits.	Failure to perform periodic security audits may lead to unidentified security risks and/or process gaps.	Periodic security audits shall focus on assessing security controls for (a) people and policy, (b) operations, (c) network, (d) platform, (e) application, (f) process, (g) physical security, and (h) third-party relationships.
Inadequate continuity of operations and disaster recovery plan.	Causes longer- than-necessary recovery from a possible plant or operational outage.	An associated cyber contingency plan and Cyber Security incident response plan shall be developed within the various plant/system disaster recovery plans in place. Disaster recovery plans shall highlight the need to determine if the disaster was created by or related to a Cyber Security incident. Steps shall be taken to validate, backup, and ensure devices being recovered are clean before installing the backups, incident reporting, etc.
Lack of adequate risk assessment process.	Inadequate understanding of the actual risk may lead to poor and ineffective decisions	A documented risk assessment process that includes consideration of business objectives, the impact to the organisation if vulnerabilities are exploited, and the determination by senior management of risk acceptance is necessary to ensure proper evaluation of risk.
Inadequate risk management process.	Could result in major risks being unaddressed	A systematic approach of risk management process shall use the results of the risk assessment to initiate timely and appropriate risk mitigation in a fashion commensurate with their likelihood and impact. An executive dashboard shall be developed to show all risks where mitigations are past due.
Insufficient incident response process.	Time-critical response actions may not be completed in a timely manner, leading to the increased duration of risk exposure.	An incident response process is required to ensure proper notification, response, and recovery in the event of an incident.

Table 21-3: Third-Party Risks and Mitigation

Risk	Impact	Mitigation
Failure to specify security requirements in RFPs.	Products/services will not meet security requirements of the system	Security requirements shall be reflected in the RFPs, and contract

Risk	Impact	Mitigation
Failure to request results of independent security testing of hardware and software prior to procurement.	Procurement may not meet standards of security requirements.	Hardware/software vendors must be required to have their products reviewed by third-party security experts and to share the reports.
Failure to request evidence from a third-party vendor of its risk management and security practices.	Products/services will have insufficient security measures	Vendor's risk management and security practices shall be reviewed to ensure that they adhere to appropriate standards.
Failure to request information from a third-party on its secure SDLC process.	A SDLC process that does not follow security development practices will likely result in insecure software.	Software vendor shall demonstrate a secure software development process.

Table 21-4: Network Risks and Mitigation

Risk	Impact	Mitigation
Unneeded services running.	Every service that runs is a security risk, because intended use of the service may provide access to system assets, and the implementation may contain exploitable bugs.	Perform analysis to identify all services that are needed, and only have these enabled. Establish a process for obtaining permission to enable additional services. Conduct periodic reviews to ensure that the services are running as expected.
Insufficient log managemen t.	(a) Failure to detect critical events; (b) Removal of forensic evidence; (c) Log wipes	Events from all devices should be logged to a central log management server. Alerts should be configured according to the criticality of the event or a correlation of certain events. For instance, when the tamper-detection mechanism on a device is triggered, an alert should be delivered to the appropriate personnel. When a remote power disconnect command is issued to x number of meters within a certain time, alerts should also be sent.

Table 21-5: Platform Risks and Mitigation

Risk	Impact	Mitigation
Insufficient Authentication and authorisation process for all components	Denial of service (DoS)/distributed denial of service (DDoS) attacks may overwhelm a software system by overloading it with data requests ultimately causing	Enforce multi-layer authentication. Institute sound key management practices. Ensure secure key exchange. Ensure that the authentication process cannot be bypassed.

Risk	Impact	Mitigation
	platform shutdown and data/assets stolen	
Monitoring for unusual activities not performed	System may be vulnerable to fraudulent activities	Ensure dedicated senior management to rigorously enforce policies and procedures

22 SYSTEM OPERATOR TRAINING

This chapter contains requirements specific to both the *EAPP IC* and the *KNTGC.* If in any instance there is a difference in requirements, the more stringent requirement shall hold.

22.1 EAPP IC REQUIREMENTS

22.1.1 Introduction

The *System Operator* Training Chapter (SOTC) sets out the responsibilities and the minimum acceptable requirements for the development and implementation of *System Operator* Training and Authorisation programmes. The SOTC shall ensure that *System Operator*s throughout *EAPP* and the *EAC* are provided with continuous and coordinated operational training in order to promote the reliability and security of the *EAPP Interconnected Transmission System.*

22.1.2 Objective

The objectives of the *System Operator* Training Chapter are to establish mandatory continuing training and authorisation to improve and maintain *System Operator* capability and performance in their job tasks.

22.1.3 Responsibility

*TSO*s shall establish and authorise the *System Operator* positions that will have the responsibility in their *Control Centre*s for the safe and reliable operation of the *EAPP Interconnected Transmission System* and *National System*. *TSOs* shall also be responsible for the ongoing training of their *System Operator*s in accordance with the SOTC. In a *TSO's Control Centre* and in the *EAPP CC* at least one *System Operator*, authorised in accordance with the SOTC, shall be on duty at all times and shall be responsible for the operation of the *EAPP Interconnected Transmission System* and for complying with the *EAPP/EAC* Interconnection Code.

22.1.4 Scope

Reliable operation of the *EAPP Interconnected Transmission System* requires highly trained and tested *System Operator*s who are able to evaluate information on the current status of their *National System* and *EAPP Interconnected Transmission System*. They must evaluate possible risks to system reliability, and make near-instant decisions about actions necessary to protect the system in a safe and reliable manner under all conditions. When recruiting *System Operator*s, each *TSO* shall ensure that they have basic qualifications and shall provide them with a continuous and coordinated training and authorisation. *System Operator*s should be selected on the basis of their level of intellectual and reasoning ability and their capacity for working under stressful conditions. They should have good engineering, mathematical and problem-solving skills and communicate clearly both in writing and verbally. *System Operator*s shall also have sufficient language skills to enable them to communicate with other *EAPP Control Centre*s under operational conditions in both the English and French languages. *System Operator*s must be able to deal with their peers in other *Control Centre*s and also with regulators, *Generation Licensee*s, and *End-users*. *System Operator*s should be capable of supervising and training other operating personnel in their own *National System*.

22.1.5 Need for Training

System expansions, new technologies, and modifications of market and regulatory rules require changing functionalities in *Control Centre*s. As the markets expand and the *EAPP Interconnected Transmission System* becomes more congested, operational reliability is crucial and requires more robust data acquisition, better analysis, and faster coordinated controls. To ensure smooth operation of the *EAPP Interconnected Transmission System* and *National Systems* under steady-state and disturbed conditions, a number of technical rules and recommendations also need to be followed. The functions and responsibilities set out above require qualified, skilled, and well-trained *System Operator*s at the *Control Centre*s to direct the operation of *EAPP Interconnected Transmission System* in a reliable and secure manner.

22.1.6 Authorisation of System Operators

*System Operator*s in the *EAPP Coordination Centre* and in the *TSO Control Centre*s shall be authorised in accordance with the SOTC. The training and authorisation of *System Operator*s is the responsibility of *EAPP* in the case of the *EAPP Coordination Centre* and individual *TSO*s in the case of their *Control Centre*s. There are two levels of authorisation:

(a) Basic Authorisation: This level of authorisation is for new recruits to the *System Operator* function and requires the completion of the Initial Course and the passing of an examination. This authorisation will be valid for three (3) years.

(b) Continuing Authorisation: This level of authorisation is for *System Operator*s who are already performing the role. The Continuous Course to be followed involves the accumulation of credits. Sufficient credits must be obtained every three (3) years in order to maintain authorisation.

22.1.7 Training of System Operators

The training of *System Operator*s consists of two courses. The content of the Initial Course is aimed at new recruits to the *System Operator* position and assumes a good knowledge of electrical engineering principles. It introduces the basics of system operation using the *EAPP Interconnected Transmission System* to illustrate the concepts and to instil knowledge on how the overall system operates at all times and under all conditions. The Initial Course is of six (6) month duration for trainees without experience in power system operation, including three (3) months for on-the-job and simulator training.

The Continuous Course is targeted at *System Operator*s to enable them to maintain their proficiency and professional development throughout their career. The Continuous Course is required to be completed before expiry of the previous authorisation and will require the accumulation of a number of credits to be defined by the *EAPP Steering Committee*.

The training programme will introduce the basics of interconnected system operation and control practices including security analysis, stability studies, optimal power flow and system management. The deregulation processes adopted in *EAPP Member Countries* will be covered. Different restructuring models and technical problems in operation and control including congestion management, *Ancillary Services*, *Automatic Generation Control*, demand forecasting, power systems security and state estimation will be discussed.

The detailed course material shall be reviewed periodically to account for changing requirements and developments in *Prudent Utility Practice*. *The EAPP Steering Committee* shall establish a Committee of experts to review the training needs to ensure that the content of both courses is relevant and covers all aspects.

22.1.8 Initial Course

22.1.8.1 Theoretical Modules

The structure of the theoretical part of the Initial Course should provide a first level of competencies in the following main topics:

(a) Types of overhead lines and underground cables with their components;

(b) Different types of *HV* and *EHV* substations, *HVDC* converters, circuit breakers, isolator-earth switches, power transformers, measurement and protection transformers, tap changers, reactors, capacitors, phase shifting transformers, other electronic regulators (*SVC, FACTS*), telecommunication systems, protection relays;

(c) Types of *Generating Units* and their operational characteristics e.g. response times.

22.1.8.2 Operation Modules

This will include all relevant national and international regulations and market rules as well as the knowledge and analysis of the necessary conditions for safe and reliable system operation. This category might include modules on the following aspects:

(a) Network behaviour, network operation, power flows and system frequency;

(b) Basics of system protection;

(c) Voltage and *Reactive Power* control;

(d) Balancing (*Primary* and *Secondary Response* and *Tertiary Reserves*), *Automatic Generation Control*;

(e) *EAPP* Interconnection Code and National Grid Codes;

(f) Other technical or operational policies of the *TSO*;

(g) Emergency scenarios including manual and automatic remedial actions and system restoration philosophies;

(h) Electricity Market operations;

(i) Communication and reporting of system incidents.

22.1.8.3 Practical Modules

Trainees should receive training in the following topics:

(a) Data collection and configuration of *SCADA* and *EMS*;

(b) Models implemented for state estimation, system, *Contingency* analysis, *Automatic Generation Control,* and demand forecasting;

(c) *System Operator*'s Man-Machine Interface;

(d) Training on Power System Protection.

22.1.8.4 Simulator Training

System Simulator based training bridges the gap between theory and practice and is also used to enhance the skills of experienced *System Operator*s. During the Initial Course trainees should use the Simulator to experience the following:

(a) Simulation of system performance under *SCADA* real-time conditions;
(b) Restoration of the system following a blackout;
(c) Use of the *Control Centre* User Interface;
(d) Decision making under stress conditions;
(e) Operation under emergency conditions.

22.1.8.5 On Job Training

Training on shift in the *Control Centre* is a most important part of the Initial Course. The training should concentrate on the future position and responsibilities of the trainee and should cover all relevant operational aspects relevant to the position. On job training puts into practice all the topics of the Theory Modules and the trainees should be supervised by experienced *System Operator*s.

22.1.9 Continuous Course

The Continuous Course is an ongoing training programme aimed at *System Operator*s who have already been authorised. It focuses on advanced theoretical and practical aspects of system operation as well as on cross-border issues. Each *TSO* should implement a Continuous Course with two modules.

22.1.9.1 Theoretical Module

The Theoretical Module should provide advanced technical knowledge on the following main topics:

(a) Analysis of past system disturbances and 'near-misses';
(b) System operation including security analysis, optimal power flow, transient and dynamic stability and operation under emergency conditions;
(c) New risks and conditions affecting system operation including new network elements or *Generating Units*;
(d) Modifications to the *EAPP/EAC* Interconnection Code and National Grid Codes and other new technical and operational rules and procedures.

22.1.9.2 Simulator Training

Training on the System Simulator should be concerned with the 'play back' of system incidents and with the lessons to be learned from them. The training should also include 'live' interaction with *Control Centre*s of *Neighbouring Systems* in the handling of cross-border incidents.

22.1.10 Combined Training

Cooperation and communication between *System Operator*s in the National *Control Centre*s and the *EAPP CC* is essential for the successful and coordinated operation of the *EAPP Interconnected Transmission System*. This cooperation shall be fostered by joint training programmes between *TSO*s. These programmes could include:

(a) Exchange visits between *Control Centre*s including periods on-shift;
(b) Joint training workshops;
(c) Common System Simulator training.

22.2 KENYA NATIONAL TRANSMISSION GRID CODE REQUIREMENTS

22.2.1 Operations Training Seminar

(a) The SO will, at a minimum, annually host a training seminar. The purpose of the training seminar is to provide a forum for system wide problems to be effectively addressed. The training seminar should present information to maintain the consistency of operators across all of the SO Region.

(b) The seminar provides a forum for *Users.* The SO shall meet and analyse common topics and issues as well as participate in formal training sessions that impact all *Users*.

22.2.2 Emergency Preparedness Drill

The SO shall conduct an emergency preparedness drill each year. This drill will be used to train on the following:

(a) scheduling and communication functions of the primary and/or backup centres;
(b) train operators in emergency procedures and handling systems during pandemics
(c) Handling system contingencies such as flooded installations, installations on fire
(d) Plus any other scenario

The SO *shall* appoint a drill coordinator for developing and coordinating the annual emergency preparedness drill. The SO shall appoint a Working Committee to review and critique the results of completed emergency preparedness drills that will ensure effectiveness and recommend changes as necessary. The SO shall verify and report participation of the Entity to the Authority.

22.2.3 Training Practices

The SO shall establish a clear requirement, define and develop a systematic approach in administering the training, and provide the necessary feedback as a measurement of curriculum suitability and trainee progress. The SO shall recognise the importance of training and provide sufficient operator participation through adequate staffing and work-hour scheduling.

The *Authority* through Agency shall certify the training practices under this Chapter.

22.2.4 Operator Certification

The *SO* Certification process shall verify that an individual has knowledge of fundamental topics in electrical power and power system operations in Kenya. The certification shall be achieved through on-job training, and undertaking of the authorization process, self-study of the *SO* Training Manual, and by successful completion of a written examination over the subject matter contained in the Manual. The recertifaiotn shall be carried out every 3 years. The SO shall establish a Training Manual which shall be reviewed on need basis.

APPENDIX A DEROGATION REQUEST AND MITIGATION PLAN FORMS

A.1 KENYA NATIONAL TRANSMISSION GRID CODE DEROGATION REQUEST FORM

Name of Entity:		**Date:**
Contact Name (CEO or delegated Officer):	**Contact Phone:**	**Email:**
Signature (CEO or delegated officer):		
Type of Derogation Being Requested (Indicate One): Exemption_____Mitigation _____ **If Mitigation: Proposed date by which mitigation plan will be filed:** **Date by which the non-compliance will be remedied:**		

Date of Non-Compliance Discovery: **Date Non-Compliance Reported:**	
Code Section Title:	**Code Section Number:**
Described the nature and extent of the Non-Compliance (Attach)	
Describe the cause of Non-Compliance (Attach)	
Identification and Description of the system, facility, equipment, process, procedures or specific connection point in respect of which the Derogation is sought (Attach)	

A.2 KENYA NATIONAL TRANSMISSION GRID CODE MITIGATION PLAN FORM

Name of Entity:		**Date:**
Code Section Title:	**Code Section Number:**	
Describe Detailed Plan to Become Compliant, including expected duration of non-compliance (Attach)		
Describe Customer/User Health and Safety Risk Mitigation Plan (Attach)		
Description of reasonable alternative actions that have been considered (Attach)		
Describe Detailed Milestone Schedule to Become Compliant (Attach)		

APPENDIX B METERING STANDARDS

The standards listed in Table B-1 shall apply to all *Metering Equipment* in Kenya.

Table B-1: Metering Standards Applied in Kenya

Standard	Type
ISO/IEC 17025	General requirements for the competence to carry out tests and/or calibrations, including sampling (covers testing and calibration performed using standard / non-standard / laboratory-developed methods)
IEC 60044 - 2 (replaced by IEC 61869 - 3)	Requirements for voltage transformers to be used with electrical measuring instruments and protective devices at frequencies from 15 Hz to 100 Hz.
IEC 60044 - 3 (replaced by IEC 61869 - 4)	Requirements for combined transformers
KS IEC 60044 -5 (replaced by IEC 61869-5)	Requirements for single-phase capacitive voltage transformers connected between line and earth for system voltages Um ≥ 72,5 kV at power frequencies from 15 Hz to 100 Hz. They are intended to supply a low voltage for measurement, control and protective functions
KS IEC 60044 -1 (replaced by IEC 61869-2)	Requirements for current transformers to be used with electrical measuring instruments and protective devices at frequencies from 15 Hz to 100 Hz.
IEC 61000 - 3-2: 2014	Electromagnetic compatibility (EMC) - Part 3-2: Limits - Limits for harmonic current emissions (equipment input current ≤ 16 A per phase)
KS IEC 62052-11:2003	Electricity Metering Equipment (a.c.) - General Requirements, Tests and Test Conditions - Part 11: Metering Equipment; Plastic Determination of Temperature Deflection of Load
IEC 62053-20:2003	Automatic Meter Reading
KS IEC 62053-21:2003	Electricity Metering Equipment (a.c.) - Particular Requirements - Part 21: Static Meters for Active Energy (class 1.0)
IEC 62053-23:2003	Electricity Metering Equipment (a.c.) - Particular Requirements - Part 23: Static Meters for Reactive Energy (classes 2 and 3)
KS IEC 62054 - 21	Accuracy of the Real Time Clock
IEC 62056-21:2003	Electricity Metering, Data Exchange for Meter Reading , Tariff, and Load Control - Part 21: Direct Local Data Exchange
KS IEC 62059	Electricity Metering Equipment Dependability

(a) **Average annual number of forced outages for all transmission lines (ANOFT)** is equal to the total number of sustained interruptions multiplied by 100km and divided by the total length of the transmission lines owned by licensee in km per voltage level.

$$SAFO\_L_{100} = \frac{\sum_{j=1}^{NL} NO_j}{\sum_{j=1}^{NL} LONG_j \big/ 100}$$

Where;

NO_j = Number of Outages of Transmission Line Circuit "j" during the reported period

NL = Total number of Transmission Line Circuits

$LONG_j$ = Length of Transmission Line Circuit "j"

(b) **Average duration of forced interruption (ADFI)** is equal to the total duration of the interruption divided by the number of the interruptions excluding force majeure and third party interferences.

$$UD_L = \frac{\sum_{j=1}^{NL} \sum_{i=1}^{kt} H_{i,j}}{NL}$$

Where;

$H_{i,j}$ = Duration of Outage "i", that affected Transmission Line Circuit "j" (in hours)

NL = Total number of Transmission Line Circuits

kt = Total number of Outages of Transmission Line Circuit "j" during the reported period

(c) **Transmission lines Monthly Availability** per voltage shall be equal to:

$$\left\{1 - \left\{\frac{Hrs\ of\ forced\ outage + Hrs\ of\ planned\ outage}{hours\ for\ the\ month}\right\}\right\} x100\%$$

(d) **Transmission line Annual Availability** per voltage shall be equal to:

$$\left\{1 - \left\{\frac{Hrs\ of\ forced\ outage + Hrs\ of\ planned\ outage}{hours\ for\ the\ year}\right\}\right\} x100\%$$

Appendix D Revision Log

Chapter	Comments	Page	Action Taken	Date of Action
All	Remove ambiguity	Various	Replace Regulatory Authority with Authority as short name for the Energy and Petroleum Regulatory Authority	21^{st} April 2017
5	Term not commonly used in Kenya	61, 64, 68	Replace servitude with wayleave	21^{st} April 2017
Various	For simplicity	Various	Replace term End-use User with End-User	8^{th} May 2017