IT is hereby notified that the Minister of Energy and Power Development, in terms of section 58(3) as read with section 65 of the Electricity Act [*Chapter 13:19*], and after consultation with the Zimbabwe Energy Regulatory Authority, has approved the publication of the Electricity Distribution Code set out in the Schedule.

"SCHEDULE

ELECTRICITY DISTRIBUTION CODE

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ACRONYMS

IPP	Independent Power Producer
AC	Alternating Current
ALD	Automatic Load Dropping
MOEPD	Ministry of Energy Power and Development
EBIT	Earning Before Interest and Taxes
GW	GigaWatt
GWh	GigaWatt-hour
HV	High Voltage
IEC	International Electrotechnical Commission
IRReg	Implementing Rules and Regulations
IRR	Internal rate of return
KA	KiloAmpere
KVARh	Kilovar-hour
kW	KiloWatt
kWh	KiloWatt-hour
LV	Low Voltage
MAIFI	Momentary Average Interruption
MLD	Manual Load Dropping
MV	Medium Voltage
MVA	MegaVolt-ampere
MVAR	Megavar
MW	MegaWatt
MWh	MegaWatt-hour
PDP	Power Development Program
QoSS	Quality of Service Supply
P/E	Price-Earnings Ratio
ROA	Return on Assets
ROI	Return on Investments
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SPUG	Small Power Utility Group
TDD	Total Demand Distortion
THD	Total Harmonic Distortion
UFR	Under-frequency Relay
V	Volts
VAR	Volt Ampere Reactive
W	Watt
Wh	Watt-hour
X/R ratio	Reactance/Resistance ratio
NGSC	National Grid Service Company
ZPC	Zimbabwe Power Company
ZERA	Zimbabwe Energy Regulatory Authority
ZERC	Zimbabwe Electricity Regulatory Commission
ZETDC	Zimbabwe Electricity Transmission and Distribution Company

INTRODUCTION

THE Electricity reforms program in Zimbabwe has resulted in two Acts being passed by Parliament. These are the Rural Electrification Fund Act [*Chapter 13:20*] and the Electricity Act [*Chapter 13:19*]. The Rural Electrification Fund Act resulted in the formation of the Rural Electrification Agency, whose mandate is to spearhead the provision of electricity in rural areas.

The Electricity Act was passed by the Parliament of Zimbabwe in January 2003 and gazetted on the 23rd May 2003 will make way to the unbundling of ZESA to form successor companies. In 2011, the Energy Regulation Act [*Chapter 13:23*] was enacted leading to the formation of the Zimbabwe Energy Regulatory Authority (ZERA), replacing ZERC.

ZETDC and other electricity distributors are licensed to construct, own, operate and maintain a distribution system in various areas of Zimbabwe and to offer the following services—

(a) to be the primary distributors of power in Zimbabwe;

(b) to be the purchaser of power from the bulk supplier for distribution in Zimbabwe;

(c) the connection of both demand and embedded customers for the purpose of receiving a supply of electricity;

(d) the installation, maintenance and reading of meters, billing and collection;

(e) such other distribution services as may be prescribed by the Authority.

PURPOSE OF DISTRIBUTION CODE

The Distribution Code is a document approved by ZERA formulated in order to ensure efficient coordinated development, operation and maintenance of the electricity Distribution System under the restructured environment. It shall be a document agreed upon and to be complied with by all users of the Distribution System.

The Distribution Code is a dynamic document that is revised periodically as per the procedures laid down, taking into account the reasonable interests and views as expressed by the stakeholders in light of the experience gained in the actual implementation of the Code.

OBJECTIVES OF THE DISTRIBUTION CODE

The Distribution Code establishes the basic rules, procedures, requirements and standards that govern the operation, maintenance, and development of the electricity Distribution Systems in Zimbabwe to ensure the safe, reliable, and efficient operation of the electricity Distribution System in Zimbabwe.

The main objective of the Distribution code is to promote sound planning, operational and connection standards in a bid to provide for reliable, secure, economic and coordinated operation of the Distribution System. This will be achieved through the following—

(a) specification of minimum operational standards;

(b) specification of minimum technical requirements;

(c) specification of minimum safety and customer handling standards;

(d) specification of information requirements and procedures;

(e) specification of minimum requirements for embedded generators;

(f) streamlining responsibilities and obligations for all the users of the Distribution System;

(g) establishment of requirements for the development of the Distribution System.

SECTION 1 - GOVERNANCE OF THE CODE

1.1 Introduction

Under the terms of the Electricity Act [*Chapter 13:19*] (4/2002), the Distributor is required to implement and ensure compliance to the Distribution Code and to periodically review the same and its implementation. Such review shall be subject to approval by ZERA.

The Governance Code describes the provisions necessary for the overall administration and review of the various aspects of the Grid Code. This Code shall be read in conjunction with the relevant legislation, the licenses issued to generators, transmission companies, distributors and retail suppliers and other operating codes that relate to the Electricity Supply Industry.

1.2 Objective

The objective of this Section is to define the method of managing the Distribution Code, submitting and pursuing of any proposed changes to the Distribution Code and the responsibility of all Users to effect that change.

1.3 Responsibilities

ZERA is the administrative authority for the Distribution Code and shall ensure that the Distribution Code is compiled, implemented and complied with for the benefit of the industry. ZERA shall perform the following functions—

- ensure that all licensees comply with the Distribution Code requirements;
- constitute the Distribution Code Review Panel (DCRP) and review its membership on an annual basis;
- consider and respond to DCRP submissions within three months after the matter has been referred to them for approval;
- publish Distribution Code documentation;
- chair all DCRP meetings in line with the requirement of the Code;
- fund the administrative activities of the DCRP.

Distribution Network Services Providers (DNSP) shall ensure that distribution agreements concluded with end-use customers or distributors shall include an obligation to comply with the Distribution Code provisions.

1.4 Distribution Code Review Panel

The Distribution Code Review Panel (DCRP) shall be constituted as follows—

- chairman to be appointed by ZERA;
- two members from ZETDC, one of which shall be Secretariat to be nominated by ZETDC;
- one member from ZPC;
- one member from ZERA;
- one member from each IPP and Embedded Generators;
- two members from bulk supply customers;
- one member from Rural Electrification Agency (REA;
- one member from Standards Association of Zimbabwe (SAZ).

Members of the Distribution Code Review Panel shall possess relevant technical skills and shall be subject to approval by ZERA. ZERA shall be immediately informed of changes in the composition of the Distribution Code Review Panel and shall approve such changes.

For continuity purposes, membership of individuals from above entities shall be permanent and any changes of member representation by entities shall be communicated in writing to ZERA within thirty (30) days.

ZETDC shall provide the secretarial functions of the Distribution Code Review Panel. In this regard, ZETDC shall designate an appropriate official to coordinate the activities of the Distribution Code Review Panel to ensure compliance to the Distribution Code, its revisions and amendments. Zimbabwe Energy Regulatory Authority (ZERA) shall approve the Distribution Code and all the amendments and ensure its compliance.

1.5 Terms of reference for the Distribution Code Review Panel

The functions of the Panel are as follows:

(1) To keep the Distribution Code and its workings under continuous scrutiny and review.

(2) To analyse any major Distribution disturbances soon after the occurrence as recommended by ZERA or any other user, and evolve any consequent revision to the Distribution Code.

(3) To consider all requests for amendment to the Distribution Code which are proposed by the Users.

(4) To publish recommendations for changes to the Distribution Code together with the reasons for the changes and any objections, if applicable.

(5) To issue guidance on the interpretations and implementation of the Distribution Code.

(6) To examine problems and disputes raised by Users.

The DCRP may hold sub-meetings with a User to discuss individual requirements and with a group of Users to prepare proposals for the Distribution Code Review Panel meeting.

1.6 Derogation to the Code

ZERA is the approval authority for the Distribution Code. Any amendments to, derogation to or exemptions from the Distribution Code shall therefore be approved only by ZERA as guided by the DCRP.

Through a special Condition, ZETDC and Distribution System Users can seek 'derogation' from ZERA to relieve the Licensee or the User of its obligation to meet the conditions of the Distribution Code for a defined time period. This is applicable were a reasonable and justifiable reason is provided by the derogation applicant to warrant consideration of a limited relaxation of a Distribution Code standard. ZERA will process the derogation application and can consult the Distribution Code review panel or inform the Distribution Code Review panel of the approval of the derogation.

1.7 Standing Committees to deal with specific issues

The Distribution Code Review Panel can at its discretion form standing committees to deliberate and recommend on specific issues governing the Code.

The Distribution Code Review Panel, at their discretion, shall invite at their meetings, Chairmen of each of the Standing Committees concerned with particular items on their Agendas. The Chairman of a Standing Committee may delegate a representative from the Standing Committee to take part in the discussions.

The Distribution Code Review Panel, at their discretion, may invite representatives from Consultants and/or any other Organisation such as Government Departments, Local Authorities, Railways, Telecommunications, Standards Association of Zimbabwe, Financing Institutions or academic / technical institutions, to attend the Panel Meeting depending on the Agenda. Such invited members can express or offer advice on the matter under consideration but act as observers in the final determination.

1.8 Distribution Code Review Panel Rules

The rules to be followed by the Panel in conducting its business shall be formulated by the Panel itself and shall be approved by ZERA. The Panel will meet at least once in three months.

No revision or modification of the Distribution Code shall be made without knowledge of the Distribution Code Review Panel and ZERA approval.

In an unusual situation where normal day-to-day operation is not possible without revision of some clauses of the Distribution Code, a provisional revision may be implemented before approval of ZERA is received, but only after discussion by the Distribution Code Review Panel through a Meeting convened on emergency basis. ZERA should promptly be intimated about the provisional revision in writing and approve the revisions within fourteen (14) days from the date of notification by the Distribution Code Review Panel.

ZERA may issue directions requiring ZETDC to revise the Distribution Code in such a manner as may be specified in those directions, and ZETDC shall promptly comply with any such directions through the Distribution Code Review Panel.

1.9 Distribution Code Review and Revisions Procedures

The Secretary shall present all proposed revisions of the Distribution Code to the Review Panel for its consideration.

ZETDC shall send the following reports to the ZERA at the conclusion of each review meeting of the Panel—

1. A report on the outcome of such review.
2. Any proposed revisions to the Distribution Code as ZETDC reasonably thinks necessary for achievement of the objectives referred to in the relevant paragraph of the Distribution Licence;
3. All written representations or objections from users raised during the review.

All revisions to the Distribution Code shall require approval of ZERA. ZETDC shall publish revisions to the Distribution Code, once approved by the ZERA.

Every change from the previous Version shall be clearly marked in the margin. In addition, a revision sheet shall be placed at the front of the Revised Version noting the number of every changed sub-section, together with a brief statement of change.

1.10 Disputes and dispute resolution

1.10.1 Disputes covered by the Distribution code

The Distribution Code Review Panel shall handle disputes regarding interpretation of the Distribution Code. If one or both parties are not satisfied with the ruling of the Panel the matter shall be referred to ZERA whose decision is final and shall be made within a period of not more than four weeks.

1.10.2 Disputes pertaining to issues not covered by the Distribution Code

Any technical relevant issues not covered by the Distribution Code shall be referred to the Distribution Code Review Panel for further consideration for inclusion in the Distribution Code. The Distribution Code Review Panel's ruling on such issues shall be binding. If any party is not satisfied by the ruling of the Distribution Code Review Panel, the matter shall be referred to ZERA. The decision of ZERA shall be final and binding.

1.10.3 Continuity of Functioning of Distribution System Users

After a dispute arises between stakeholders in the distribution sector, the matter should immediately be referred to the Distribution Code Review Panel who should make provisional working arrangements that shall be implemented till a valid ruling is issued according to Section 1.10.1 above. The objective of this procedure is to ensure that no dispute shall stall the daily operations of any Distribution System User.

1.10.4 Version Control

(1) The Distribution Code will evolve as the electricity supply industry in Zimbabwe evolves.
(2) Each of the sections and codes that collectively form the Zimbabwe Distribution Code shall have separate version control and approvals.
(3) The Secretariat shall be responsible for version control.

1.10.5 Unforeseen Circumstances

In situations not addressed by any clause of the Distribution Code, ZETDC shall convene an emergency meeting with all affected Distribution System Users to formulate a solution and the actions to be taken in the circumstance by the Distribution System Users. If no agreement can be reached, ZETDC shall provisionally determine the action to be taken after giving consideration to the views expressed by other Users.

ZETDC shall, as soon as possible, but not later than fourteen days, refer the matter to the Distribution Code Review Panel whose decision shall prevail over the provisional determination of ZETDC. If a Distribution System User appeals to ZERA over the decision of the Panel, the decision of ZERA shall supersede the decision of the Panel.

The normal operations of any User should never be unduly disrupted by any situation or dispute. The majority decision of the meeting of Distribution System Users or the considered determination of ZETDC shall be implemented unless and until the Distribution Code Review Panel issues a different ruling; and the ruling of the Panel shall be in force unless and until a different decision is issued by ZERA (if the issue is referred to ZERA). The decision of ZERA is ultimate and shall be implemented by all Distribution System Users

SECTION 2 - DISTRIBUTION CONNECTION CODE

2.1 PURPOSE AND SCOPE

2.1.1 Purpose

To specify the technical, design, and operational criteria at the User's Connection Point;

To ensure that the basic rules for connection to the Distribution System are fair and non-discriminatory for all Users; and

To list and collate the data required by the Distributor from the User, and to list the data to be provided by the Distributor to the User.

Scope of Application

This Section applies and is binding to all Distribution System Users including:

- other licensed distributors;
- embedded generators;
- ZETDC;
- large customers; and
- any other User System connected to the Distribution System.

2.1.2 Distribution Technical, Design and Operational Criteria

Power Quality Standards

The Distributor shall ensure that at any Connection Point in the Distribution System, the Power Quality standards specified in Section 3 of this Distribution Code are complied with and these should be done through—

(1) commissioning of connection points;

(2) regular inspections.

Users seeking connection to the Distribution System or modification of an existing connection shall ensure that their Equipment can operate reliably and safely within the limits specified in Section 3.2 during normal conditions, and can withstand the limits specified in this Section.

2.1.3 Frequency Variations

2.1.3.1 The Distributor shall design and operate its system to assist in maintaining the System Frequency within the limits specified in Section 3.2.2 of this Distribution Code.

2.1.3.2 In case the System frequency momentarily rises to 52.5 Hz or falls to 47.5Hz, all Embedded Generating Units shall remain in synchronism with the Distribution System for at least five (5) seconds to allow the System Operator to undertake measures to correct the situation.

2.1.3.3 The Distributor shall take into account the maximum estimated Frequency Variation during emergency conditions in the specification of Distribution Equipment.

2.1.4 Voltage Variations

2.1.4.1 The Long Duration Voltage Variation at any Connection Point during normal conditions shall be within the limits specified in Section 3.2.3 of this Distribution Code.

2.1.4.2 ZETDC and other distributors shall consider the maximum estimated Voltage Swell in the selection of the voltage ratings of Distribution Equipment.

2.1.4.3 Any extension or connection to the Distribution System shall be designed in such a way that it does not adversely affect the Voltage Variation in the Distribution System.

2.1.5 Power Factor

2.1.5.1 The User shall maintain a Power Factor not less than 90 percent lagging (p.f of 0.9) at the Connection Point in the Distribution System refer to Table 3.2.8 below.

2.1.5.2 ZETDC shall correct feeder and substation feeder bus Reactive Power demand to a level that will economically reduce the Technical Losses referred to in section 3 on Power quality and guaranteed performance standards.

2.1.5.3 ZETDC shall establish penalties and incentives for Customer Power Factor at the Connection Point based on the target level.

2.1.6 Harmonics

2.1.6.1 The Total Harmonic Distortion of the voltage and the Total Demand Distortion of the current, at any Connection Point, shall not exceed the limits prescribed in Section 3.2.4.

2.1.6.2 The user shall ensure that its System shall not cause the Harmonics in the Distribution System to exceed the limits specified in Section 3.2.4.

2.1.7 Voltage Unbalance

2.1.7.1 The maximum Voltage Unbalance at any Connection Point in the Distribution System shall not exceed the limits specified in Section 3.2.14 during normal operating conditions.

2.1.7.2 The Customer shall ensure that its System shall not cause the Voltage Unbalance in the Distribution System to exceed the limits specified in Section 3.2.14.

2.1.8 Flicker Severity

2.1.8.1 The Flicker Severity at any Connection Point in the Distribution System shall not exceed the limits specified in Section 3.2.12.

2.1.8.2 The user shall ensure that its System shall not cause the Flicker Severity in the Distribution System to exceed the limits specified in Section 3.2.12.

2.1.9 Transient Voltage Variations

2.1.9.1 The Distribution System and the User System shall be designed and operated to include devices that will mitigate the effects of transient over voltages on the Distribution System and the User System.

2.1.9.2 ZETDC and the customer shall take into account the effect of electrical transients when specifying the insulation of their electrical Equipment as shown below:

Basic Insulation Level					
VOLTAGE (kV)	132	88	66	33	11
B.I.S (kV)	650	550	350	170	75

2.1.10 Protection Arrangements

2.1.10.1 The Distribution System shall be designed and operated with sufficient protection to ensure safety and to limit the frequency and duration of Interruptions to End-Users in accordance the engineering manual and distribution planning manual.

2.1.10.2 The requirements for the protection system at the Connection Point shall be agreed upon by the Distributor and the User during the application for connection or modification of an existing connection and shall be reviewed from time to time by ZETDC, with the concurrence of the User.

2.1.10.3 The User System shall be designed and operated with protective devices in accordance with the requirements of the Distributor.

2.1.10.4 The Fault Clearance Time shall be within the limits established by ZETDC in accordance with the protection policy adopted for the Distribution System referred to in section 7.6.

2.1.10.5 The distributor shall provide the details of any auto-reclosing or sequential switching features in the Distribution System so that the Customer may take this into account in the design of its protection System.

2.1.10.6 The user shall consider in the design of its protection System the possible disconnection of only one phase or two phases during fault conditions.

2.1.11 Equipment Short Circuit Rating

2.1.11.1 ZETDC shall inform the Customer of the designed and the existing Fault Levels of the Distribution System at the Connection Point upon request.

2.1.11.2 The Customer shall consider the designed and the existing Fault Levels at the Connection Point in the design and operation of the Customer System.

2.1.12 Grounding Requirements

2.1.12.1 The Distributor shall inform the Customer of the grounding method used in the Distribution System. The specification of Distribution Equipment shall consider the maximum Voltage Surge that will be imposed on the Equipment during faults involving ground.

2.1.12.2 The Distribution System shall be effectively grounded with an Earth Fault Factor of less than 1.4 for all voltage levels connected to the Distribution System.

2.1.12.3 Where there are multiple sources of power, the Customer shall ensure that the effects of circulating currents with respect to the grounded neutral are prevented.

2.1.13 Monitoring and Control Equipment Requirements

2.1.13.1 ZETDC and the large Customer shall agree on the mode of monitoring and control.

2.1.13.2 ZETDC shall where applicable provide, install, and maintain the telemetry outstation and all associated Equipment needed to monitor the Customer System.

2.1.13.3 If the Customer agrees that ZETDC shall control the switchgear in the Customer's System, ZETDC shall install the necessary control outstation, including the control interface for the switchgear.

2.1.14 Equipment Standards

All Equipment at the Connection Point shall comply with the requirements of the IEC Standards or their equivalent Zimbabwe national standards.

2.1.15 Maintenance Standards

2.1.15.1 All Equipment at the Connection Point shall be maintained in accordance with the provisions of Section 2 of this Distribution Code and in a manner that shall not pose a threat to the safety of any personnel or cause damage to the Equipment of the Distributor or the User.

2.1.15.2 The Distributor shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the User.

2.1.15.3 The User shall maintain a log containing the test results and maintenance records relating to its Equipment at the Connection Point and shall make this log available when requested by the Distributor.

2.2 PROCEDURES FOR DISTRIBUTION CONNECTION OR MODIFICATION

2.2.1 Connection Agreement

2.2.1.1 Any Customer seeking a new connection to the Distribution System shall secure the required Connection Agreement with ZETDC prior to the actual connection to the Distribution System.

2.2.1.2 ZETDC shall develop application procedures for connection to the distribution system to be used by customers for application to be connected to the Distribution System. The application for connection procedures shall be approved by ZERA.

2.2.1.3 A customer requiring new connection/alteration to existing supply shall provide all technical details requested by the distributor to enable the distributor to make a fair assessment of the customer's requirements.

2.2.1.4 Before the customer is physically connected, the distributor shall satisfy itself that the installation is safe to be connected. These safety requirements shall be approved and monitored by ZERA.

2.2.1.5 The distributor shall provide a certificate of electrical safety for every installation established.

2.2.1.6 A connection agreement, detailing among others the contracted supply and applicable tariff, shall be drafted by the distributor and signed by both distributor and customer in respect of each and every connection/supply point.

2.2.1.7 A new connection to the distribution network shall be by means of a single or three phase overhead line with bare or insulated conductors, an underground cable or a combination of both in accordance with Electricity (Supply) Regulations.

2.2.1.8 All equipment on the customer's installation shall be suitable for use at the operating frequency of 50 Hz and at the voltage and stipulated short-circuit rating and shall normally be controlled within the approved limits.

2.2.1.9 The distributor may require certification and evidence to conclusively prove that the equipment installed or to be installed has been designed, tested and installed in a satisfactory manner and in conformance with the relevant standards.

2.2.2 Amended Connection Agreement

2.2.2.1 Any customer seeking to modify an existing connection to the Distribution System shall secure the required Amended Connection Agreement with the Distributor prior to the actual modification.

2.2.2.2 Any alteration (be it temporary or permanent) to an existing installation shall not be made without approval from the Distributor.

2.2.2.3 The Amended Connection Agreement shall include provisions for the submission of additional information required by ZETDC

2.2.3 Distribution Impact Studies

2.2.3.1 The distributor shall take all necessary measures to ensure that any proposed connection or modification of an existing connection to the Distribution System shall not result in the degradation of the Distribution System.

2.2.3.2 The distributor shall conduct Distribution Impact Studies to evaluate the impact of the proposed connection or modification to an existing connection on the Distribution System. The evaluation shall include the following—

- fault level study;
- impact of local embedded generator on the network;
- coordination of protection System;
- impact of User Development on Power Quality; and
- impact of User Development on the Environment

2.2.3.3 The distributor may disapprove an application for connection or a modification of an existing connection to the Distribution System if it is determined through the Distribution Impact Studies that the proposed connection or modification will result in the derogation of the Distribution System.

2.2.4 Conditions for Disconnection of Supply

An installation may be disconnected for the following reasons:

(a) on customer's written request;

(b) in cases of emergency;

(c) in the event of violation of electricity safety regulations;

(d) in the event of violation of commercial agreements such as follows:

- the supply of electricity to a customer's electrical installation is used other than at the customer's premises;

- a customer takes at the customer's supply address electricity supplied to another supply address;
- a customer tampers with, or permits tampering with, the meter or associated equipment; or
- a customer allows electricity supplied to the customer's supply address to bypass the meter.
- failure by customer to comply to any provision of this Distribution Code

2.2.5 Conditions for Reconnection of Supply after disconnection

An installation/customer may be reconnected for the following reasons:

- on customer's written request
- compliance with relevant electricity regulations where a disconnection was effected in terms of section 2.2
- compliance with relevant commercial terms and agreements.

2.2.6 Application for Connection or Modification

2.2.6.1 Any Customer applying for connection or a modification of an existing connection to the Distribution System shall submit to the Distributor the completed application form for connection or modification of an existing connection to the Distribution System. The application form shall include the following information:

(a) a description of the proposed connection or modification to an existing connection, which shall comprise the Customer Development at the Connection Point;

(b) the relevant Standard Planning Data as requested by the Distributor; and

(c) the Completion Date of the proposed Customer Development.

2.2.7 Processing of Application

2.2.7.1 The Distributor shall establish the procedure for the processing of applications for connection or modification of an existing connection to the Distribution System.

The customer can contract the distributor to do the work, or hire a private constructor to do the work but the distributor has to be involved during the construction period.

2.2.7.2 The distributor must use best endeavours to connect the customer on the date agreed with the customer. Where no date is agreed, the distributor shall use best endeavours to connect the supply address within 20 business days after the request.

2.2.7.3 The Distributor shall evaluate the impact of the proposed User Development on the Distribution System.

2.2.7.4 After evaluating the application submitted by the User, The Distributor shall inform the Customer whether the proposed Customer Development is acceptable or not.

2.2.7.5 If the application of the Customer is acceptable, The Distributor and the Customer shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be.

2.2.7.6 If the application of the Customer is not acceptable, The Distributor shall notify the Customer why its application is not acceptable. The Distributor shall include in its notification a proposal on how the Customer's application will be acceptable to the Distributor.

2.2.7.7 The Customer shall accept the proposal of The Distributor within 30 days, or a longer period specified in The Distributor's proposal, after which the proposal automatically lapses.

2.2.7.8 The acceptance by the Customer of The Distributor's proposal shall lead to the signing of a Connection Agreement or an Amended Connection Agreement.

2.2.7.9 If the Distributor and the Customer cannot reach agreement on the proposed connection or modification to an existing connection, the Distributor or the User may bring the matter before the ZERA for resolution.

2.2.7.9.1 This complete set of information is referred to as a 'competent application'.

Once all these conditions have been met ZETDC will start developing the agreement for you.

These application fees shall be reviewed from time to time and be subject to ZERA approval. The fees are meant covers the reasonable costs of work anticipated to arise from reviewing the connection application and preparing the associated offer to connect, including, but not limited to, acquisition and provision of relevant network data, design reviews, planning assessments, maintenance and updating of planning resources.

If late changes to the details of the customer application are made when the customer application is at an advanced stage in terms of processing, ZETDC has the right to request an adjustment of the application fee or a new application fee as may be found to be proportional to the volume of work created by the customer change.

2.2.7.9.2 Clock start Date

The Date the customer application status gains its competency becomes the Clock Start Date for processing the application. Once each of these criteria has been fulfilled and checked the customer will be informed of the clock start date of their project, which will be the day on which the last item to fulfil the application criteria was received by ZETDC and the application is therefore judged to be fully competent. A connection offer is then required to be made to the customer within 30 calendar days unless otherwise the customer changes application requirements adequately to reasonably affect the required application processing time. The Connection Offer shall comprise of the following elements—

(1) Quotation; and

(2) Connection Agreement.

If the customer application is acceptable, ZETDC and the customer shall sign a Connection Agreement or an Amended Connection Agreement, as the case may be. If the application is not acceptable, ZETDC shall notify the customer why its application is not acceptable. ZETDC shall include in its notification a proposal on how the customer's application will be acceptable. The customer shall accept the proposal of ZETDC within sixty (60) calendar days after which the proposal automatically lapses. If ZETDC and the customer cannot reach an agreement on the proposed connection, ZETDC or the customer may bring the matter before ZERA for resolution.

Once the Connection Offer is acceptable to the customer, the customer shall notify ZETDC in writing and through payment of the indicated project administration fees found in the connection offer, PPA negotiations will then commence for a generator connection application.

2.2.8 Submittals Prior to the Commissioning Date

2.2.8.1 The following shall be submitted by the Customer prior to the commissioning date, pursuant to the terms and conditions and schedules specified in the Connection Agreement:

(a) specifications of major Equipment not included in the Standard Planning Data and Detailed Planning Data;

(b) details of the protection arrangements and settings for Embedded Generating Units and for other Customer;

(c) information to enable The Distributor to prepare the Fixed Asset Boundary;

(d) electrical diagrams of the Customer's Equipment at the Connection Point;

(e) information that will enable the Distributor to prepare the Connection Point Drawings, referred to in Section 2.8;

(f) a list of the names and telephone numbers of authorised representatives, including the confirmation that they are fully authorised to make binding decisions on behalf of the Customer.

2.2.9 Commissioning of Equipment and Physical Connection to the Distribution System

2.2.9.1 Upon completion of the User Development, including work at the Connection Point, the Equipment at the Connection Point and the User Development shall be subjected to the Test and Commissioning procedure as set by the Distributor.

2.2.9.2 The Customer shall then submit to the Distributor a statement of readiness to connect.

2.2.9.3 Upon acceptance of the User's statement of readiness to connect, the Distributor shall, within 15 days, issue a certificate of approval to connect.

2.2.9.4 The physical connection to the Distribution System shall be made only after the Distributor has issued the certificate of approval to connect to the User.

2.3 REQUIREMENTS FOR EMBEDDED GENERATORS

This section of the Code is applicable to all existing or prospective Generators having Generating Plant operating or capable of operating in parallel with the distribution system.

2.3.1 The Embedded Generator's Equipment shall be connected to the Distribution System at the voltage level agreed to by the Distributor and the Generator based on the Distribution Impact Studies.

2.3.2 The embedded generating facility shall be equipped with a high voltage device capable of isolating the interconnection transformer from the Distribution System in the event of a fault within the transformer or the Generator side. The controlling circuit breaker shall be capable of interrupting the maximum short circuit current at the Point of Connection as specified by the Distributor. In addition, isolators shall be provided to adequately isolate the circuit breaker for maintenance purposes at the Point of Connection.

2.4 INTERCONNECTION TRANSFORMER REQUIREMENTS

2.4.1 Interconnection Transformer Requirements For Non-Synchronous Generators

It is desired that there be no zero sequence current contribution from induction type embedded generators. To achieve this objective, the embedded generator transformer inter-connection shall be:

(a) delta on the generator side with a grounded Wye on the distribution side; or

(b) grounded Wye on the distribution system side with a grounded or ungrounded Wye on the low voltage side. The grounded Wye connection on the low voltage side is only acceptable if the generator has a Delta or ungrounded Wye winding connection.

2.4.2 Interconnection Transformer Requirements For Synchronous Generators and Self-Commutating Inverters

The Zimbabwe distribution system is designed as an effectively grounded system. All embedded generating facilities that utilise synchronous generators shall have a step-up transformer-winding configuration that provides a ground current source, which qualifies as effectively grounded. The interconnecting transformer must have:

(a) a solidly grounded Wye connected high voltage winding with a Delta connected low voltage winding; or

(b) a delta connected high voltage winding with a separate grounding transformer connected to the high voltage terminals of the interconnecting transformer. In this case, the grounding transformer shall be connected directly to the interconnecting transformer terminals without an isolating device. The grounding transformer shall be in the same zone of protection as the interconnecting transformer.

2.4.3 Transformer Rating

2.4.3.1 The transformer shall be sized to deliver rated kW and kVAr. Rated kVAr shall be based upon 0.85 power factor full load operation for induction generators and 0.90 power

factor full load operation for synchronous generators (Generator's Reactive Power Capacity Curve shall be used as guide in this case).

2.4.3.2 The embedded generating facility owner must take into consideration the presence of unbalanced loads on the distribution system and size transformers with Wye and delta windings to accommodate the continuous zero sequence currents that will flow in the transformer as a result of this load unbalance.

2.4.4 Protection Systems for Embedded Generators

2.4.4.1 The Generator shall submit all the proposed settings on their protection scheme to the Distributor for review of protection coordination.

2.4.4.2 The Distributor and the Embedded Generator shall be solely responsible for the protection System of the electrical Equipment and facilities at their respective sides of the Connection Point.

2.4.4.3 For Generating Plant directly connected to the distribution system the Embedded Generator shall meet the target clearance times for fault current interchange with the distribution system in order to reduce to a minimum the impact on the distribution system of faults on circuits owned by Embedded Generators.

2.4.4.4 The distributor shall ensure that the distribution system protection settings meet its own target clearance times. The target clearance times are measured from fault current inception to arc extinction and shall be specified by the distributor to meet the requirements of the relevant part of the distribution system.

2.4.5 Over Current and Earth Fault Protection

2.4.5.1 Embedded generators shall be equipped with over-current and earth fault protection to trip the generator off in the event of a fault on distribution system or a fault within the generator.

2.4.5.2 Some embedded generators may require the application of more sophisticated protection schemes such as distance type protection in order to achieve coordination with the distribution system protection systems.

2.4.5.3 Voltage restrained over current protection may facilitate better coordination with distribution system's protection systems.

2.4.6 Over and Under Frequency Protection

All embedded generators are required to have under and over-frequency protection relays that will disconnect the Generator from the Distribution System if the frequency is outside the limits 47.5 Hz and 52.5 Hz.

2.4.7 Over and Under Voltage Protection

2.4.7.1 Embedded generators shall have under and over-voltage protection relays which will disconnect the generator from the distribution system in the event of abnormal voltages occurring on the distribution system.

2.4.7.2 The under-voltage trip setting shall be adjustable over a range of 85% of nominal to 95% of nominal. The over-voltage trip setting shall be adjustable over a range of 105% to 115% of nominal.

2.4.7.3 The under-voltage and over-voltage protection shall have adjustable time delays. The time delay shall be independently adjustable for the over and under voltage trip settings.

2.4.7.4 It may be advantageous to provide a separate instantaneous or very high speed over voltage protection for the detection of self-excitation or ferroresonance conditions.

2.4.8 No-volts Auto Reclose Protection

Most rural distribution systems apply auto-reclosing to the primary distribution system. If the embedded generating facility cannot withstand the acceleration that will occur following reclose, it is required that the generating facility be equipped with a no-volts relay that trips the facility off during the reclose dead time.

2.4.9 Reverse Power Protection

All embedded generators shall have protection designed to trip the unit in the event of power flowing from the Distribution System into the Generator under any condition excerpt when start-up supplies are required or for auxiliary supplies when the Generator is not on line.

2.4.10 Safety

The equipment of Generators, including machines, devices, overhead lines, underground cables, transformers, work standards, etc, shall conform to ZESA Electrical Safety Rules, SAZ Standards and other Statutory instruments such as Factories and Works Act, regulations and rules that may from time to time be in existence in Zimbabwe. In addition where such rules are not in place IEC standards (IEC 950) shall be used in the interim pending development of national standards.

2.4.11 Fault Levels

The distributor shall ensure that the fault level at the point of common coupling between the embedded generating unit and the network does not cause fault levels in the distribution system to exceed the levels specified below.

Table 2.4.11: Distribution System Fault Levels

Voltage Level	System Fault Level MVA	Short Circuit Level kA
225/390 V	15	6
11Kv	500	20
33kV	1 500	31.5
88kV	7 500	40
132kV	10 000	45

2.4.11.2 The addition of embedded generator will generally increase the system fault levels. Before embedded generating plant is added to the distribution network, it shall be assessed whether existing distribution equipment will be able to sustain the increased fault levels.

2.4.11.3 If after system modelling it is established that the connection of a generating plant is likely to increase fault levels above system design ratings, consideration shall be given to the installation of reactors, sectionalising networks, connection to systems at a higher voltage, changing the generating unit specification or other means of limiting fault current in-feed.

2.4.11.4 If fault limiting measures are not cost effective or feasible, system plant with the potential to be subjected to fault levels in excess of its rating shall be replaced or reference made to the relevant manufacturer to determine whether or not the existing plant rating(s) can be enhanced.

2.4.11.5 When assessing fault levels against system design ratings, suitable safety margins shall be allowed to cater for tolerances that exist in the network data and generating unit parameters used in fault level calculation programs. On request from the embedded generating facility operator, the Distributor shall provide the rationale for determining the value of a specific margin being used in system studies.

2.4.11.6 In assessing the prospective fault levels imposed on the power system equipment, consideration must be given to all likely or reasonably foreseeable conditions of actual application or use of the generating plant. These will include studies under asset replacement and asset maintenance conditions, so that all credible network-running arrangements have been assessed. Where alternate feeds exist to the circuit being considered, fault levels should be established for feeding from both directions.

2.4.11.7 If the network fault levels are such that mitigating actions are required for some infrequent running arrangements, then the Generator may be required to constrain the operational regime of the proposed generating plant during such running arrangements.

2.4.11.8 The level of load used in the assessment shall reflect the requirement to meet the needs from agreed projects as well as additional loads as declared in the Distributor's Long Term Development Plans.

2.4.11.9 The embedded generating facility operator shall take cognisance of the effect of Transmission and Subtransmission Long-term plans on Distribution Network fault levels.

2.4.12 System Unbalance

2.4.12.1 In the presence of voltage unbalance, generator output may have to be reduced to avoid overloading the generator. The embedded generating facility operator must take into consideration that most locations on Zimbabwe's distribution system have a degree of continuous voltage unbalance (e.g. those supplying furnace loads), and has to specify the rating of their generators appropriately to allow them to deliver planned output.

2.4.12.2 The generator must also be able to withstand the effect of voltage unbalances resulting from system disturbances such as unbalanced power line faults.

2.4.12.3 The Embedded Generating Unit shall also be required to withstand without tripping, the unbalance loading during clearance by the Backup Protection of a close-up phase-to-phase fault on the Distribution System.

2.4.13 Frequency Control

2.4.13.1 The frequency of supply to consumers shall be maintained within the range 47.5 Hz to 52.5 Hz under both normal and emergency conditions. The Generator must be capable of supplying its registered capacity within this frequency range.

2.4.13.2 The Embedded Generating Unit shall be capable of continuously supplying its Active Power output, as specified in the Generator's Declared Data, within the System Frequency range of 47.5Hz to 52.5 Hz. Any decrease of power output occurring in the Frequency range of 47.5Hz to 45.5 Hz shall not be more than the required proportionate value of the System Frequency decay.

2.4.13.3 The Embedded Generating Unit shall be capable of supplying its Active Power and Reactive Power outputs, as specified in the Generator's Declared Data, within the Voltage Variation specified in Section 2 during normal operating conditions.

2.4.13.4 The Embedded Generating Unit shall be capable of supplying its Active Power output, as specified in the Generator's Declared Data, within the limits of 0.85 Power Factor lagging and 0.90 Power Factor leading at the Generating Unit's terminals, in accordance with its Reactive Power Capability Curve.

2.4.14 Frequency Withstand Capability

2.4.14.1 If the System frequency momentarily rises to 52.5 Hz or falls to 47.5 Hz, Embedded Generating Units shall remain in synchronism with the Grid for at least five (5) seconds. The Distributor, in Consultation with the System Operator, may waive this requirement, if there are sufficient technical reasons to justify the waiver.

2.4.14.2 The Generator shall be responsible for protecting its Embedded Generating Units against damage for frequency excursions outside the range of 47.5 Hz and 52.5 Hz. The Generator shall decide whether or not to disconnect its Embedded Generating Unit from the Distribution System.

2.4.15 Speed-Governing System

2.4.15.1 During Island Grid operation, an Embedded Generating Unit providing Ancillary Services for Frequency Regulating Reserve shall provide Frequency Control to the Island Grid.

2.4.15.2 The Embedded Generating Unit providing Ancillary Services for Frequency Regulating Reserve shall be fitted with a fast-acting speed governing system. The speed-governing System shall have an overall speed droop characteristic of five percent (5%) or less. Unless waived by the Distributor in consultation with the Grid Owner and the System Operator, the speed-governing System shall be capable of accepting raise and lower signals from the Control Centre of the System Operator.

2.4.16 Power Islanding

Power islanding is the condition where the embedded generating facility and a portion of the distribution system has become isolated from the rest of the network, and continues to operate in an isolated mode.

2.4.16.1 All embedded generating facilities that cannot meet the frequency performance set in 2shall be equipped with protection systems, which detect a power islanding condition, and trip the generator. This may require re-coordination with the distribution system protection or the installation of special communication and protection schemes to send direct trips to the embedded generator.

2.4.16.2 It is conceivable that a part of the distribution system, to which Embedded Generators are connected, can, during emergency conditions, become detached from the rest of the distribution system. It shall be necessary for the distributor to decide, dependent on local network conditions, if it is desirable for the Embedded Generators to continue to generate onto the islanded distribution system.

2.4.16.3 If no facilities exist for the subsequent resynchronisation with the rest of the distribution system then the Embedded Generator shall under the distributor's instruction, ensure that the Generating Plant is disconnected for re-synchronisation.

2.4.16.4 Under emergency conditions there is an expectation that some generation shall continue to operate outside the statutory frequency limits. However, for Embedded Generators connected to the distribution system at a voltage level less than 132kV it is likely that this could mean connection within an automatic low frequency load disconnection zone. Consequently, Embedded Generators should ensure that all Protection on Generating Plant should have settings to co-ordinate with those on the automatic low frequency load disconnection equipment in conformance with the requirements of the Zimbabwe Grid Code.

2.4.17 Voltage Variations

The following voltage limits shall be adhered to, under both normal and contingency operating conditions.

Table 2.4.17: Voltage Variations

Nominal Voltage (kV)	Normal Conditions		[1]Emergency Conditions	
	Maximum (kV)	Maximum (kV)	Maximum (kV)	Maximum (kV)
132	138.6	125.1	145.0	118.8
88	92.4	83.6	96.8	79.2
66	69.3	59.4	72.5	56.1
33	34.7	31.4	36.3	29.7
11	11.6	10.5	12.1	9.9

2.4.18 Voltage and Power Factor Control Requirements

2.4.18.1 An Embedded Generating Facility using an induction generator shall be equipped with sufficient power factor correction capacitors to correct the full load power factor within the range of 0.85 lagging and 0.98 leading at the Generating Unit's terminals.

2.4.18.2 The power factor correction capacitors shall normally be provided in steps to follow the output of the generator. Sufficient steps shall be provided to maintain the power factor of the generator within the stipulated limits over the expected power output range.

2.4.18.3 The capacitors switched in at start up shall be sized to meet the voltage deviation requirements set out in Section 2.4.17.

2.4.18.4 The power factor controller shall have a voltage override that causes it to switch out capacitors if the voltage at the point of delivery exceeds an upper limit to be specified by the Distribution System Operator. Currently the normal upper limit is 1.10 per unit; however, the power factor control equipment shall have provision to adjust this upper limit between 1.00 pu and 1.15 pu.

2.4.18.4 All generating units shall have a fast response automatic excitation control system to control the generation set voltage without instability over the entire operating range of the generation set. This shall be dependent on the size and type of generating plant and the adjacent part of the Distribution System to which it is connected.

[1] Emergency conditions are those not exceeding 30 minutes

2.4.19 Special Requirements for Synchronous Generators

2.4.19.1 Synchronizing Facilities

2.4.19.1.1 The embedded generating facility is required to have facilities to facilitate synchronisation of its units to the Distribution System.

2.4.19.1.2 These facilities will typically consist of a synchronizing relay and a sync-check relay. The settings on these relays shall be submitted to the Distribution System Operator for review to insure that they will not adversely affect the operation of the Distribution System.

2.4.19.1.3 The embedded generating facility is responsible for synchronizing its generator to the Distribution System following instructions as set out in the Connection Agreement.

2.4.19.2 Voltage Regulation Requirements

2.4.19.2.1 All embedded generators shall be capable of operating continuously while maintaining a voltage between 0.90 pu and 1.10 pu of the rated generator voltage at the interconnector bus.

2.4.19.2.2 The rated power output of a generating unit shall not be affected by voltage changes within the limits declared by the Distributor. Synchronous machines shall be capable of delivering rated output power at a power factor of +0.90 (lagging) or -0.95 (leading).

2.4.19.2.3 Synchronous machines shall be equipped with a voltage regulator and exciter with the capability to control the terminal voltage of the generator continuously between 0.8 pu and the upper limit of the rated voltage of the generator from no-load to full-load.

2.4.19.2.4 The Distributor shall determine the actual set point. The regulator shall be capable of controlling the generator terminal voltage to within 0.5% of the set point without hunting.

2.4.19.2.5 In order to coordinate with its existing voltage control devices, the Distributor may require that synchronous generators operate in a power factor control mode.

2.4.19.2.6 The voltage/power factor regulator shall be capable of controlling the power factor of the generator between +0.95 and -0.95 from no-load to full-load as set by the Distributor

2.4.19.2.7 The regulator shall be capable of controlling the power factor to within 0.5% of the set point without hunting.

2.4.19.2.8 In power factor control mode, the voltage regulator shall have a voltage override that causes it to reduce excitation if the voltage at the Point Of Delivery exceeds an upper limit to be specified by the Distribution System Operator. The normal upper limit is 1.10pu; however, the voltage regulator shall have provision to adjust this upper limit between 1.00pu and 1.15pu.

2.4.19.2.9 The voltage regulator shall have provision for a time delay between sensing an excursion of the upper voltage and initiating control action.

2.4.19.2.10 The power factor control equipment shall have provision to allow for the adjustment of this time delay between 0 and 180 seconds. The Distribution System Operator will specify the required time delay.

2.4.19.2.11 The excitation system shall not trip, and shall continue to operate during faults on the distribution system, and shall recover and return to normal operation immediately following the fault. Controls should continue to operate down to generator terminal voltages approaching 20% of rated voltage, and shall continue to operate during the extremely unbalanced voltage conditions that could occur during fault conditions on the Distribution System.

2.4.20 Self-Excitation

In a power islanding condition, self-excitation of the generator will take place if the reactive load on the generator resulting from line capacitance or capacitors on the Distribution System exceeds the capability of the generator and its excitation/voltage regulator system to control the voltage. The voltage rise following the onset of self-excitation in a synchronous machine can be very rapid and may only be limited by saturation effects. Self-excitation is exacerbated by the over-frequency that may follow a partial loss of load. The over-voltages resulting from self-excitation can be very high and may result in apparatus damage.

2.4.20.1 The embedded generating facility shall demonstrate through the execution of analytical studies, that there is no risk of self-excitation of the generator. Otherwise the embedded generating facility shall demonstrate to the Distribution System Operator's satisfaction:

(a) that the embedded generating facility has protection systems to detect a self-excitation condition;

(b) that the interrupting device provided by the embedded generating facility is capable of switching the anticipated leading power factor current at the anticipated elevated voltages;

(c) that isolation of the embedded generator will occur quickly enough to preclude damage to other customers or the distribution system equipment from the abnormal voltages that may occur.

2.4.20.2 If the embedded generating facility fails to meet the preceding requirements it shall be responsible for the cost of installing special protection schemes. This may include a direct trip signal from the distribution system operator's source substation to the embedded generating facility or other generating facilities on the same feeder. This allows the interconnecting breaker to switch off whenever there is a trip on the feeder to which the embedded generator is connected.

2.4.20.3 The risk of self-excitation shall be assessed taking into consideration the total amount of capacitance on the feeder to which the embedded generating facility is connected. This includes discrete capacitors on the feeder, and the distributed capacitance of the feeder itself.

2.4.20.4 The assessment must also take into consideration the presence of existing generators on the same feeder along with the minimum load likely to be connected to the feeder.

2.4.20.5 The distribution system operator will provide information on load, feeder characteristics, and the location of capacitors on its system to facilitate assessment of the risk of self-excitation. Such details are site specific.

2.4.21 Metering Requirements

2.4.21.1 The metering shall be located on the secondary side of the interconnecting transformer and compensated for losses to the point-of-delivery.

2.4.21.2 Dual register, revenue approved metering capable of recording real and reactive power and energy delivery to and from the embedded generating facility separately shall be required.

2.4.21.3 The embedded generating facility owner shall provide any communication and interface facilities that the Distribution System Operator may require to the metering unit.

2.4.21.4 The Distribution System Operator shall provide the Generator with all relevant information on metering requirements.

2.4.22 System Studies

2.4.22.1 System studies shall be carried out by the Distributor (the Generator shall provide all relevant information as the Distributor may require in order to carry out these system studies) using appropriate software to determine the following:

- System fault levels after adding embedded generators;
- Effect of adding embedded generators on system losses;
- Dynamic stability after adding embedded generators;
- Transient stability after adding embedded generators;

- Steady state stability after adding embedded generators;
- Effect of loss of the generator on distribution system losses and voltages;
- Network conditions (Voltages, Real and reactive line flows, direction of power flow etc) before and after selected system disturbances.

2.4.22.2 Simulations shall also be carried out using appropriate software to investigate possibility of self-excitation for generating facilities after applying certain contingencies.

2.4.23 Dispatch of Embedded Generators

The System Operator (ZETDC) shall determine whether an embedded generating facility should be independently dispatched or centrally dispatched. This decision depends on among other things, the impact of the proposed embedded generating facility on economic load dispatch.

2.4.24 Black Start Capability

2.4.24.1 The Embedded Generator shall specify in its application for a Connection Agreement or an Amended Connection Agreement if its Embedded Generating Unit has a Black Start capability.

2.4.24.2 The Embedded Generating Unit providing Ancillary Services for Black Start shall be capable of initiating a Black Start procedure in accordance with Section 5.7.4.

2.4.25 Fast Start Capability

2.4.25.1 The Embedded Generator shall specify in its application for a Connection Agreement or Amended Connection Agreement if its Embedded Generating Unit has a Fast Start capability.

2.4.25.2 The Embedded Generating Unit providing Ancillary Services for Fast Start shall automatically Start-Up in response to frequency-level relays with settings in the range of 47.5 Hz to 52.5 Hz.

2.4.26 Negative Sequence Voltage

2.4.26.1 Any generating unit or generating plant connected to the distribution system shall be required to withstand, without tripping, the Negative Phase Sequence loading incurred during the clearance of a close-up phase-to-phase fault by system back-up Protection which shall be within the Plant short time rating on the distribution system.

2.4.26.2 The distributor shall advise Embedded Generators of the expected Negative Phase Sequence loadings during the Connection Agreement process.

2.4.26.3 Neutral Earthing winding configuration and method of earthing connection shall be agreed with the distributor.

2.4.26.4 An embedded generator must ensure that an embedded generating unit's contribution to the negative sequence voltage at the point of connection between the embedded generating unit and the distribution system is less than 1%.

2.4.27 Generating Plant Commissioning Tests

2.4.27.1 Where Generating Plant requires connection to the distribution system in advance of the commissioning date, for the purpose of testing, the Embedded Generator shall comply with the requirements of the Connection Agreement.

2.4.27.2 The Embedded Generator shall provide the distributor with a commissioning program, approved by the distributor to allow commissioning tests to be coordinated.

2.4.28 Harmonics

An embedded generator must ensure that an embedded generating unit's contribution to the harmonic distortion levels in the supply voltage at the point of connection between the embedded generating unit and the distribution system is within the limits specified in Section 3.

2.4.29 Inductive interference

An embedded generator must ensure that its generating unit does not cause inductive interference above the limits specified in section 3 of this Distribution Code.

2.4.30 Emergency Response Plan

A distributor must develop and periodically test emergency response plans in co-ordination with relevant organisations. Working instructions and procedures shall be made available for ease of reference.

2.5 PROVISION OF INFORMATION

For the Distributor to effectively model the distribution network, it is necessary for the Embedded Generating Facility operator to provide the following information on each Generator to the Distributor:

(a) The Generating Plant Data

(1) terminal volts (kV);

(2) machine rating (MVA);

(3) machine rating (MW);

(4) registered capacity sent out;

(5) minimum active power sent out (MW min.);

(6) reactive power capability at registered capacity and minimum generation (lagging and leading);

(7) rated power factor lagging at machine terminals;

(8) type of generation set (synchronous, asynchronous etc);

(9) type of prime mover (e.g. fossil, wind etc.);

(10) anticipated operating regime of generation set (e.g. continuous, intermittent, peaking);

(11) fault level contribution;

(12) type of generator set;

(13) proposed interface arrangements;

(14) means of connection with earth;

(15) precautions should neutral become disconnected from earth;

(16) short circuit ratio;

(17) zero sequence resistance;

(18) zero sequence reactance;

(19) negative and positive sequence resistance;

(20) negative and positive sequence reactance;

(21) type of excitation system;

(22) inertia constant MW secs/MVA (whole machine);

(23) direct axis reactance (Sub transient, transient and synchronous);

(24) quadrature axis reactance (Sub transient, transient and synchronous);

(25) direct axis Sub-transient time constant;

(26) direct axis transient time constant;

(27) quadrature axis reactance Sub-transient time constant;

(28) maximum active power sent out (MW max.);

(29) reactive power requirements (MVAr) if any;

(30) generator rotor saturation parameters and saturation characteristics. It is also recommended that saturation curves be provided.

(b) Model Data

(1) Automatic Voltage Regulator:- A block diagram (in s-transform format) for the model of the AVR system including the data on the gains, forward and feedback gains, time constants and voltage control limits.

(2) Speed Governor & Prime Mover Data: A block diagram (in s-transform format) for the model of the Generating Plant governor detailing the governor flyball, if applicable, and system control and turbine time constants together with the turbine rating and maximum power.

(c) Interconnection Transformer Data

(1) voltage ratio of transformer;

(2) Transformer Rating (MVA);

(3) transformer tap arrangement;

(4) vector group of transformer;

(5) per unit impedance;

(6) method of earthing of transformer;

(d) Interface Arrangements.

The following interconnection information shall also be provided:

(1) sketches of system layout and the proposed interface arrangements between the generating plant and the Distribution System;

(2) the means of synchronisation between the Distribution System and the Generator;

(3) details of arrangements for connecting with earth that part of the Generator's system directly connected to the Distribution System;

(4) the means of connection and disconnection that are to be employed;

(5) precautions to be taken to ensure the continuance of safe conditions should any earthed neutral point of the generator's system operated at high voltage become disconnected from earth;

(6) operation diagrams showing the electrical circuitry of the existing and proposed main features within the generating facility and showing as appropriate busbar arrangements, phasing arrangements, earthing arrangements, switching facilities and operating voltages;

(7) sketches and diagrams showing point of connection to the Distribution System in terms of geographical location and electrical location.

2.5.1 Requirements for Distribution Customers

2.5.1.1 Requirements Relating to the Connection Point

2.5.1.1.1 The Customer's equipment shall be connected to the Distribution System at voltage level agreed to by The Distributor and the Customer based on the Distribution Impact Studies.

2.5.1.1.2 For a connection at Low Voltage, the Connection Point shall, in general, be at the Customer's Load side terminal of the metering equipment.

2.5.1.1.3 For a connection at Medium Voltage and High Voltage, The Distributor and the User shall agree upon the Connection Point arrangements.

2.5.1.1.4 The Connection Point shall be controlled by a Circuit Breaker that is capable of interrupting the maximum short circuit current at the point of connection.

2.5.1.1.5 Disconnect switches shall also be provided and arranged to isolate the circuit breaker for maintenance.

2.5.2 Protection Arrangements

2.5.2.1 The protection of the Customer's Equipment at the Connection Point shall be designed, coordinated, and tested to achieve the desired level of speed, sensitivity, and selectivity in fault clearing and to minimize the impact of faults on the Distribution System.

2.5.2.2 The Distributor and the Customer shall be solely responsible for the protection System of electrical Equipment and facilities at their respective sides of the Connection Point.

2.5.2.3 The Distributor may require specific Customers to provide other protection schemes, designed and developed to minimize the risk and/or impact of disturbances on the Distribution System.

2.5.3 Transformer Connection and Grounding

The Distributor shall specify the connection and grounding requirements for the transformer, in accordance with the provisions of Section 2.2.

2.6 FIXED ASSET BOUNDARY DOCUMENT REQUIREMENTS

2.6.1 Fixed Asset Boundary Document

2.6.1.1 The Fixed Asset Boundary Documents for any Connection Point shall provide the information and specify the operational responsibilities of the Distributor and the User for the following:

(a) MV/HV Equipment;

(b) LV Equipment; and

(c) Metering equipment.

2.6.1.2 For the Fixed Asset Boundary Document referred to in item (a) above, the responsible management unit shall be shown, in addition to the Distributor or the User. In the case of Fixed Asset Boundary Documents referred to in items (b) and (c) above, with the exception of protection equipment and inter-trip Equipment operation, it will be sufficient to indicate the responsible User or the Distributor.

2.6.1.3 The Fixed Asset Boundary Document shall show precisely the Connection Point and shall specify the following:

(a) equipment and their ownership;

(b) accountable managers;

(c) safety rules and procedures including Local Safety Instructions and the Safety Coordinator(s) or any other persons responsible for safety;

(d) operational procedures and the responsible party for operation and control;

(e) maintenance requirements and the responsible party for undertaking maintenance; and

(f) any agreement pertaining to emergency conditions.

2.6.1.4 The Fixed Asset Boundary Documents shall be available at all times for the use of the operations personnel of the Distributor and the Customer.

2.6.2 Accountable Managers

2.6.2.1 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the Customer shall submit to the Distributor a list of Accountable Managers who are duly authorised to sign the Fixed Asset Boundary Documents on behalf of the Customer.

2.6.2.2 Prior to the Completion Date specified in the Connection Agreement or Amended Connection Agreement, the Distributor shall provide the Customer the name of the Accountable Manager who shall sign the Fixed Asset Boundary Documents on behalf of the Distributor.

2.6.2.3 Any change to the list of Accountable Managers shall be communicated to the other party at least six (6) weeks before the change becomes effective. If the change was not anticipated, it must be communicated as soon as possible to the other party, with an explanation why the change had to be made.

2.6.2.4 Unless specified otherwise in the Connection Agreement or the Amended Connection Agreement, the construction, test and commissioning, control, operation and maintenance of equipment, accountability, and responsibility shall follow ownership.

2.6.3 Preparation of Fixed Asset Boundary Document

2.6.3.1 The Distributor shall establish the procedure and forms required for the preparation of the Fixed Asset Boundary Documents.

2.6.3.2 The Customer shall provide the information that will enable the Distributor to prepare the Fixed Asset Boundary Document, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

2.6.3.3 The Distributor shall prepare the Fixed Asset Boundary Documents for the Connection Point at least two (2) weeks prior to the Completion Date.

2.6.3.4 The Fixed Asset Boundary Document for the Equipment at the Connection Point shall include the details of the lines or cables emanating from the Distributor's and the User's sides of the Connection Point.

2.6.3.5 The date of issue and the issue number shall be included in every page of the Fixed Asset Boundary Document.

2.6.4 Signing and Distribution of Fixed Asset Boundary Document

2.6.4.1 Prior to the signing of the Fixed Asset Boundary Document, the Distributor shall send a copy of the completed Fixed Asset Boundary Document to the Customer, for any revision or for confirmation of its accuracy.

2.6.4.2 The Accountable Managers designated by the Distributor and the Customer shall sign the Fixed Asset Boundary Document, after confirming its accuracy.

2.6.4.3 Once signed but not less than two (2) weeks before the implementation date, the Distributor shall provide two (2) copies of the Fixed Asset Boundary Document to the User, with a notice indicating the date of issue, the issue number and the implementation date of the Fixed Asset Boundary Document.

2.6.5 Modifications of an Existing Fixed Asset Boundary Document

2.6.5.1 When a Customer has determined that a Fixed Asset Boundary Document requires modification, it shall inform the Distributor at least eight (8) weeks before implementing the modification. the Distributor shall then prepare a revised Fixed Asset Boundary Document at least six (6) weeks before the implementation date of the modification.

2.6.5.2 When the Distributor has determined that a Fixed Asset Boundary Document requires modification, it shall prepare a revised Fixed Asset Boundary Document at least six (6) weeks prior to the implementation date of the modification.

2.6.5.3 If the Distributor or a Customer has determined that the Fixed Asset Boundary Document requires modification to reflect an emergency condition, the Distributor or the Customer, as the case may be, shall immediately notify the other party. The Distributor and the Customer shall meet to discuss the required modification to the Fixed Asset Boundary Document, and shall decide whether the change is temporary or permanent in nature.

2.6.5.4 Within seven (7) days after the conclusion of the meeting between the Distributor and the User, the Distributor shall provide the Customer a revised Fixed Asset Boundary Document.

2.6.5.5 The procedure specified in Section 2.6 for signing and distribution shall be applied to the revised Fixed Asset Boundary Document. The Distributor's notice shall indicate the revision, the new issue number, and the new date of issue.

2.6.6 Electrical Diagram Requirements

2.6.6.1 Responsibilities of ZETDC and Customers

2.6.6.1.1 ZETDC shall specify the procedure and format to be followed in the preparation of the Electrical Diagrams for any Connection Point.

2.6.6.1.2 The Customer shall prepare and submit to ZETDC an Electrical Diagram for all the Equipment on the Customer's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

2.6.6.1.3 If the Connection Point is at the Customer's Site, the Customer shall prepare and distribute a composite Electrical Diagram for the entire Connection Point. Otherwise, ZETDC shall prepare and distribute the composite Electrical Diagram for the entire Connection Point.

2.6.7 Preparation of Electrical Diagrams

The Electrical Diagrams shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.

2.6.7.1 If possible, all the Equipment at the Connection Point shall be shown in one Electrical Diagram. When more than one Electrical Diagram is necessary, duplication of identical information shall be minimised. The Electrical Diagrams shall represent, as closely as possible, the physical arrangement of the Equipment and their electrical connections.

2.6.7.2 The Electrical Diagrams shall be prepared using the Site and Equipment Identification prescribed in Section 4.12. The current status of the Equipment shall be indicated in the diagram. For example, a decommissioned switch bay shall be labelled "Spare Bay."

2.6.7.3 The title block of the Electrical Diagram shall include the names of authorised persons together with provisions for the details of revisions, dates, and signatures.

2.6.8 Changes to Electrical Diagrams

2.6.8.1 If ZETDC or a User decides to add new Equipment or change an existing Equipment Identification, ZETDC or the User, as the case may be, shall provide the other party a revised Electrical Diagram, at least one (1) month prior to the proposed addition or change.

2.6.8.2 If the modification involves the replacement of existing Equipment, the revised Electrical Diagram shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

2.6.8.3 The revised Electrical Diagram shall incorporate the new Equipment to be added, the existing Equipment to be replaced or the change in Equipment Identification.

2.6.9 Validity of Electrical Diagrams

2.6.9.1 The composite Electrical Diagram prepared by ZETDC or the user, in accordance with the provisions of Section 2.7, shall be the Electrical Diagram to be used for all operational and planning activities associated with the Connection Point.

2.6.9.2 If a dispute involving the accuracy of the composite Electrical Diagram arises, a meeting between ZETDC and the User shall be held as soon as possible, to resolve the dispute.

2.6.10 Connection Point Drawing Requirements

2.6.10.1 Responsibilities of ZETDC and Customers

2.6.10.1.1 ZETDC shall specify the procedure and format to be followed in the preparation of the Connection Point Drawing for any Connection Point.

2.6.10.1.2 The Customer shall prepare and submit to ZETDC the Connection Point Drawing for the Customer's side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

2.6.10.1.3 ZETDC shall provide the User with the Connection Point Drawing for its side of the Connection Point, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement

2.6.10.1.4 If the Connection Point is at the Customer Site, the customer shall prepare and distribute a composite Connection Point Drawing for the entire Connection Point otherwise, ZETDC shall prepare and distribute the composite Connection Point Drawing for the entire Connection Point.

2.6.11 Preparation of Connection Point Drawings

2.6.11.1 The Connection Point Drawing shall provide an accurate record of the layout and circuit connections, ratings and identification of Equipment, and related apparatus and devices at the Connection Point.

2.6.11.2 The Connection Point Drawing shall indicate the Equipment layout, common protection, and control and auxiliaries. The Connection Point Drawing shall represent,

as closely as possible, the physical arrangement of the Equipment and their electrical connections.

2.6.11.3 The Connection Point Drawing shall be prepared using the Site and Equipment Identification prescribed in Section 4.12. The current status of the Equipment shall be indicated in the drawing. For example, a decommissioned switch bay shall be labelled "Spare Bay."

2.6.11.4 The title block of the Connection Point Drawing shall include the names of authorised persons together with provision for the details of revisions, dates, and signatures.

2.6.12 Changes to Connection Point Drawings

2.6.12.1 If ZETDC or a User decides to add new Equipment or change an existing Equipment Identification, ZETDC or the User, as the case may be, shall provide the other party a revised Connection Point Drawing, at least one (1) month prior to the proposed addition or change.

2.6.12.2 If the modification involves the replacement of existing Equipment, the revised Connection Point Drawing shall be provided to the other party in accordance with the schedule specified in the Amended Connection Agreement.

2.6.12.3 The revised Connection Point Drawing shall incorporate the new Equipment to be added, the existing Equipment to be replaced, or the change in Equipment Identification.

2.6.12.4 ZETDC and the User shall, if they have agreed to do so in writing, modify their respective copies of the Connection Point Drawings to reflect the change that they have agreed on, in accordance with the schedule specified in the Connection Agreement or Amended Connection Agreement.

2.6.13 Validity of the Connection Point Drawings

2.6.13.1 The composite Connection Point Drawing prepared by the Distributor or the User, in accordance with Section 2.8, shall be the Connection Point Drawing to be used for all operational and planning activities associated with the Connection Point.

2.6.13.2 If a dispute involving the accuracy of the composite Connection Point Drawing arises, a meeting between the Distributor the User shall be held as soon as possible, to resolve the dispute.

2.6.14 Distribution Data Registration

2.6.14.1 Data to be Registered

2.6.14.1.1 The data relating to the Connection Point and the Customer Development that are submitted by the User to ZETDC shall be registered according to the following data categories:

(a) forecast data;

(b) estimated equipment data; and

(c) registered equipment data.

2.6.14.1.2 The Forecast Data, including Demand and Active Energy, shall contain the Customer's best estimate of the data being projected for the five (5) succeeding years.

2.6.14.1.3 The Estimated Equipment Data shall contain the Customer's best estimate of the values of parameters and information about the Equipment for the five (5) succeeding years.

2.6.14.1.4 The Registered Equipment Data shall contain validated actual values of parameters and information about the Equipment that are submitted by the User to ZETDC at the connection date. The Registered Equipment Data shall include the Connected Project Planning Data, which shall replace any estimated values of parameters and information about the Equipment previously submitted as Preliminary Project Planning Data and Committed Project Planning Data.

2.6.15 Stages of Data Registration

2.6.15.1 The data relating to the Connection Point and the User Development that are submitted by a User applying for a Connection Agreement or an Amended Connection Agreement shall be registered in three (3) stages and classified accordingly as:

(a) preliminary project planning data;

(b) committed project planning data; and

(c) connected project planning data;

2.6.15.2 The data that are submitted at the time of application for a Connection Agreement or an Amended Connection Agreement shall be considered as Preliminary Project Planning Data. These data shall contain the Standard Planning Data specified in Section 4 including the Detailed Planning Data, when required ahead of the schedule specified in the Connection Agreement or Amended Connection Agreement.

2.6.15.3 Once the Connection Agreement or the Amended Connection Agreement is signed, the Preliminary Project Planning Data shall become the Committed Project Planning Data, which shall be used in evaluating other applications for Distribution System connection or modification of existing Distribution System connections and in preparing the Distribution Development Plan.

2.6.15.4 The Estimated Equipment Data shall be updated, confirmed, and replaced with validated actual values of parameters and information about the Equipment at the time of connection, which shall become the Connected Project Planning Data. These data shall be registered in accordance with the categories specified in Section 2.9 (of The Zimbabwe Grid Code) and shall be used in evaluating other applications for Distribution System connection or modification of existing Distribution System connections and in preparing the Distribution Development Plan.

2.6.16 Data Forms

ZETDC shall develop the forms for all data to be submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

SECTION 3 - PERFORMANCE STANDARDS AND CUSTOMER SERVICES CODE

3.1 PURPOSE AND SCOPE

3.1.1 Purpose

(a) to ensure the *quality* of electric power in the Distribution System;

(b) to ensure that the Distribution System will be operated in a *safe and efficient manner* and with a high degree of reliability;

(c) to specify Customer Services for the *protection* of the End-Users; and

(d) to specify *safety standards* for the protection of personnel in the work environment.

3.1.2 Scope of Application

This Chapter applies to all Distribution System Users including:

(a) ZETDC;

(b) embedded generators;

(c) users.

3.2 POWER QUALITY STANDARDS FOR DISTRIBUTORS

3.2.1 Power Quality Problems

3.2.1.1 For the purpose of this section, Quality shall be defined as the quality of the voltage, including its frequency and the resulting current, that are measured in the Distribution System during normal conditions.

3.2.1.2 A Power Quality problem exists when at least one of the following conditions is present and significantly affects the normal operation of the System:

The System Frequency has deviated from the nominal value of 50 Hz;

(a) voltage magnitudes are outside their allowable range of variation;

(b) harmonic Frequencies are present in the System;

(c) there is imbalance in the magnitude of the phase voltages;

(d) the phase displacement between the voltages is not equal to 120 degrees;

(e) voltage fluctuations cause Flicker that is outside the allowable Flicker Severity limits; or

(f) high-frequency over voltages are present in the Distribution System.

3.2.2 Frequency Variations

3.2.2.1 The nominal fundamental Frequency shall be 50 Hz.

3.2.2.2 The Distributor shall design and operate its System to assist the System Operator in maintaining the fundamental Frequency within the limits of 47.5 Hz and 52.5 Hz during normal conditions.

3.2.3 Voltage Variations

3.2.3.1 A Distributor must maintain a nominal voltage level at the point of supply to the customer's electrical installation subject to applicable regulations, at one of the following standard nominal voltages:

(a) 225V

(b) 390V

(c) 11kV

(d) 33kV

(e) 88kV

(f) 132kV

3.2.3.2 Variations from the relevant standard nominal voltage listed in Clause 3.2.3.1 may occur in accordance with Table 3.2.3 below.

Table 3.2.3: Standard Nominal Voltage Variations

Voltage Level	Voltage Range for Time Periods			Impulse Voltage
	Steady State Variation	Less than 1 minute	Less than 10 seconds	
225V 390V	+/-6%	+/-10%	Phase to Earth +50% -100% Phase to Phase +20% -100%	6kV peak
11kV	+/-10%	+/-10%	Phase to Earth +80% -100% Phase to Phase +20% -100%	95kV peak
33kV	+/-10%	+/-10%	Phase to Earth +80% -100% Phase to Phase +20% -100%	170kV
88kV	+/-10%	+/-15%	Phase to Earth +80% -100% Phase to Phase +20% -100%	550kV
132kV	+/-10%	+/-15%	Phase to Earth +80% -100% Phase to Phase +20% -100%	650kV

3.2.3.3 A Distributor must control over voltage in accordance with IEC 60364-4-443 and/or in accordance with Electricity (Supply) Regulations.

3.2.3.4 A Distributor must use best endeavors to minimize the frequency of voltage variations allowed under Section 3.2.3.2 for periods of less than 1 minute.

3.2.3.5 A Distributor may send, in accordance with IEC 1000-2-2, signals for the following:

- ripple control systems; or
- medium-frequency power-line carrier systems; or
- frequency power-line carrier systems

3.2.3.6 A Distributor must monitor and record:

- steady state voltages and voltage variations at each primary distribution substation in its distribution system which are outside the limitations specified in Table 3.2.3 and
- steady state voltages and voltage variations of a duration of more than one minute which are outside the range of steady state voltages specified in Table 3.2.3 at the extremity of one feeder supplied from each of those primary distribution substation zones.

3.2.3.7 Without limiting the liability of a distributor under any other compensate any person whose property is damaged due to voltage variations outside the limits prescribed by Table 3.2.3 and in accordance with any relevant regulations and guidelines approved by ZERA.

3.2.4 Harmonics

3.2.4.1 For the purpose of this Section, Harmonics shall be defined as sinusoidal voltages and currents having Frequencies that are integral multiples of the fundamental Frequency.

3.2.4.2 The Total Harmonic Distortion (THD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the fundamental quantity, expressed in percent.

3.2.4.3 The Total Demand Distortion (TDD) shall be defined as the ratio of the RMS value of the harmonic content to the RMS value of the rated or maximum fundamental quantity, expressed in percent.

3.2.4.4 A distributor must endeavor to keep harmonic levels in the voltage at points of common coupling nearest to a customer's point of supply within the levels specified in Table 3.2.4 below:

Table 3.2.4.4: Voltage Harmonic Distortion Limits

Voltage at Point of Common Coupling	Total Harmonic Voltage Distortion VT (%)	Individual Harmonic Voltage Distortion (%)	
		Odd	Even
Up to 390V	5%	4%	2%
11kV	4%	3%	1.75%
33kV	3%	2%	1%
88kV	1.5%	1%	0.5%
132kV	1.5%	1%	0.5%

3.2.4.5 Subject to Section 3.2, a distributor must comply with the IEEE Standard 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

3.2.4.6 A customer must keep harmonic currents below the limits specified in Table 3.2.4.6 and otherwise comply at its nearest point of common coupling with the IEEE Standard 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

Table 3.2.4.6: Current Harmonic Distortion Limits

	Maximum Harmonic Current Distortion in Percent IL					
	Individual Harmonic Order "h" (Odd Harmonics)					
ISC/IL	<11	11≤h17	17≤h<23	23≤h <35	35≤h	Total Harmonic Distortion
<20*	4.0%	2.0%	1.5%	0.6%	0.3%	5.0%
20<50	7.0%	3.5%	2.5%	1.0%	0.5%	8.0%
50<100	10.0%	4.5%	4.0%	1.5%	0.7%	12.0%
100<1000	12.0%	5.5%	5.0%	2.0%	1.0%	15.0%
>1000	15.0%	7.0%	6.0%	2.5%	1.4%	20.0%

Notes:

1. Even harmonics are limited to 25% of the odd harmonics listed above.
2. Current distortions that result in a DC offset, e.g. half-wave converters are not allowed.
3. *All power generation equipment is limited to these values of current distortion, regardless of actual ISC/IL.
4. Isc = maximum short-circuit current at point of common coupling.
5. IL = maximum demand load current (fundamental frequency component) at point of common coupling.

3.2.5 Disturbing Loads

3.2.5.1 A distributor must maintain voltage fluctuations at the point of common coupling at a level no greater than the levels specified in appropriate regulations and guidelines.

3.2.5.2 Subject to Section 3.2, a customer must ensure that the customer's equipment does not cause voltage fluctuations at the point of common coupling greater than the levels specified by the distributor and approved by ZERA.

3.2.5.3 If two or more customers' electrical installations are connected at the same point of common coupling, the maximum permissible contribution to voltage fluctuations allowable from each customer is to be determined in proportion to their respective maximum demand, unless otherwise agreed.

3.2.6 Inductive Interference

A distributor must ensure that inductive interference caused by its distribution system is within the limits specified in applicable regulations and guidelines.

3.2.6.1 Negative Sequence Voltage

A distributor shall maintain the negative sequence voltage at the point of common coupling to a customer's three-phase electrical installation at a level at or less than 2% of the positive sequence voltage.

3.2.6.2 The negative sequence voltage may vary above 2% of an applicable voltage level, but not for more than 5 minutes in every 30-minute period.

3.2.7 Load Balance

3.2.7.1 A customer must ensure that the current in each phase of a three phase electrical installation does not deviate from the average of the three phase currents:

(a) by more than 5% for a standard nominal voltage up to 1kV; and

(b) by more than 2% for a standard nominal voltage above 1kV.

3.2.7.2 Notwithstanding Section 3.2 above, deviations are permissible for periods of less than 2 minutes:

(a) up to 10% for a standard nominal voltage up to 1kV; and

(b) up to 4% for a standard nominal voltage above 1kV.

3.2.8 Power Factor

3.2.8.1 A customer must ensure that the customer's demand for reactive power does not exceed the maximum level allowed by applying the power factor limits specified in Table 3.2.8 to the customer's maximum demand for apparent power (measured in kVA) or active power (measured in kW).

3.2.8.2 If, for the purposes of clause 3.2.8.1 above, the customer's maximum demand for apparent power (Rmax) is used, then the customer's allowable demand for reactive power (Qmax) is calculated using the formula Qmax = Rmax*(1-pfmin2)1/2, where pfmin is the minimum power factor specified in Table 3.2.8.

3.2.8.3 If, for the purposes of clause 3.2.8.1 above, the customer's maximum demand for active power (Pmax) is used, then the customer's allowable demand for reactive power (Qmax) is calculated using the formula Qmax = (Pmax/pfmin)*(1-pfmin2)1/2, where pfmin is the minimum power factor specified in Table 3.2.8.

3.2.8.4 If the customer's network tariff includes a charge for the maximum demand for apparent or active power, then, for the purposes of this clause 3.2.8.3, the customer's maximum demand for apparent or active power is to be taken to be the maximum demand for which it was most recently billed.

3.2.8.5 A customer must use best endeavors to keep the power factor of its electrical installation within the relevant range set out in Table 3.2.8 when the customer's demand for active or apparent power is at or more than 50% of the customer's maximum demand.

3.2.8.6 A customer shall ensure that the electrical installation's demand for reactive power is maintained within power factor limits shown in Table 3.2.8.

Table 3.2.8: Power Factor Limits

Supply Voltage	Power Factor Range for Customer Maximum Demand and Voltage					
	Up to 200kVA		Between200kVA-2MVA		Over 2MVA	
	Minimum Lagging	Minimum Lagging	Minimum Lagging	Minimum Lagging	Minimum Lagging	Minimum Lagging
225V	0.75	0.75	0.8	0.8	0.85	0.85
390V	0.75	0.75	0.8	0.8	0.85	0.85
11kV	0.8	0.8	0.85	0.85	0.9	0.9
33kV	0.8	0.8	0.85	0.85	0.9	0.9
88kV	0.85	0.85	0.9	0.9	0.95	0.95
132kV	0.85	0.85	0.9	0.9	0.95	0.95

3.2.9 Power Factor Penalty

A customer that does not maintain its power factor above the minimums stated in Table 3.2.8 above shall be levied an appropriate power factor penalty per month until the customer corrects such poor power factor. The applicable penalties and levies shall be subject to ZERA's approval.

3.2.10 Voltage Fluctuation and Flicker Severity

If the voltage fluctuates, the luminous intensity of the lamps and TV's will fluctuate correspondingly. If the fluctuation is of a magnitude and frequency perceptible to the eye, it becomes flicker. Flicker could range from annoying to complete interference of normal activity. Flicker is not usually produced by the power System but by customer loads such as arc furnaces, compressors, starting of large motors, etc. Since voltage fluctuation of the System affects other users on the same System, ZETDC shall direct the management of flicker on its lines and station buses. At the same time, flicker-generating loads connected to the System have to be controlled. ZETDC reserves the right to disconnect any excessive flicker-generating load until the Distribution System User rectifies the problem.

3.2.11 Indicator of Quality for System Flicker

Flicker is the impression of unsteadiness of visual sensation induced by a light stimulus whose luminance or spectral distribution fluctuates with time. It is generated by customers and is indicated by the short-term flicker severity index index Pst, as defined in IEC Standard 61000-3-7 and measured with a flicker meter that meets the specification of IEC Standard 868 or IEC Std 61000-4-15. For the purpose of regulation, Pst, the short-term flicker severity index, is selected as the indicator of quality. Pst is considered to be the measure of visual severity of flicker derived from a time series output of a flicker meter over a ten-minute interval.

3.2.12 Limits

Pst = 1, which is equivalent to the threshold of perception, is the allowable level of flicker on the Distribution System. Tolerance for customer-generated flicker varies with the relative strength (short circuit ratio) of the load and voltage level. Limits are given in the following table.

Table 3.2.12: Limits of flicker produced by Users

Short Circuit Ratio SL/SCC	Voltage	Pst
SL/SCC □ 0.04	HV	0.37
	EHV	0.58
SL/SCC □□0.04	HV	0.8
	EHV	1

3.2.13 Monitoring Control and Measurement

Substations, which supply heavy industrial loads such as furnaces, steel mills, etc., are targets for flicker monitoring. Other substations and Connection Point will be selected for monitoring on a random basis. At least one site is monitored each month. The list of monitoring points is submitted to Distribution System Users for approval at least 2 months before the monitoring. The flicker measurement will be conducted at 10-minute intervals according to procedures outlined in IEC Std 61000-4-15. Each site is measured for one (1) week

3.2.14 Voltage Unbalance

3.2.14.1 For the purpose of this Section, Voltage Unbalance shall be defined as the maximum deviation from the average of the three phase voltages divided by the average of the three phase voltages, expressed in percent.

3.2.14.2 The maximum Voltage Unbalance at the Connection Point of any User, excluding the Voltage Unbalance passed on from the Distribution System shall not exceed 2.5 percent during normal operating conditions.

3.2.14.3 The phase voltages of a 3-phase supply should be of equal magnitude and 120o apart in phase angle. Deviations will result in decreased efficiency, negative torque, vibrations and overheating. Severe unbalance could lead to malfunctioning of some equipment. Voltage unbalance is defined as:

$$\text{Voltage Unbalance} = \frac{\text{Deviation between highest and lowest phases}}{\text{Average voltage of three phases}}$$

Limits for voltage unbalance are:

220 kV and above:	2%
Below 220 kV:	3%

Balancing loads on individual phases will help greatly in avoiding unbalanced voltages.

3.2.15 Transient Voltage Variations

3.2.15.1 For the purpose of this Section, Transient Voltages shall be defined as the high frequency over voltages that are generally shorter in duration compared to the Short Duration Voltage Variations.

3.2.15.2 Infrequent short-duration peaks may be permitted to exceed the levels specified in Section 3.2 for TDD and THD provided that such increases do not compromise the service to other End-Users or cause damage to any Equipment in the Distribution System.

3.3 RELIABILITY STANDARDS FOR DISTRIBUTORS

3.3.1 Criteria for Establishing Distribution Reliability Standards

3.3.1.1 ZERA shall impose a uniform system of recording and reporting of Distribution System reliability performance.

3.3.1.2 The same reliability indices shall be imposed on all Distribution Utilities.

3.3.1.3 The Distribution System shall be evaluated quarterly to compare its actual performance with the targets.

3.3.2 Distribution Reliability Indices

3.3.2.1 Distributor's Targets

3.3.2.2 Before 31st December each year, a distributor must publish in its customer protection standards and in a newspaper with wide circulation, its targets for reliability of supply for the following year.

3.3.2.3 As a minimum, these targets (which shall distinguish between customers supplied from urban feeders and rural feeders) shall include:

(a) System Average Interruption Frequency Index (SAIFI);

(b) System Average Interruption Duration Index (SAIDI); and

(c) Momentary Average Interruption Frequency Index (MAIFI).

3.3.2.4 The System Average Interruption Frequency Index shall be defined as the total number of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

3.3.2.5 The System Average Interruption Duration Index shall be defined as the total duration of sustained Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

3.3.2.6 The Momentary Average Interruption Frequency Index shall be defined as the total number of momentary Customer power Interruptions within a given period divided by the total number of Customers served within the same period.

3.4 INCLUSIONS AND EXCLUSIONS OF INTERRUPTION EVENTS

3.4.1 A power Interruption shall include any Outage in the primary Distribution System, extending from the distribution substation to the distribution transformers, which may be due to the tripping action of protective devices during faults or the failure of primary distribution lines and/or transformers, and which results in the loss of service to one or more Customers or Users.

3.4.2 The following events shall be excluded in the calculation of the reliability indices:

(a) outages that occur on the secondary lines of the Distribution System;

(b) outages due to generation, transmission line, or transmission substation failure;

(c) planned outages where the customers or users have been notified at least three (3) days prior to the loss of power;

(d) outages that are initiated by the System Operator during the occurrence of Significant Incidents or the failure of their facilities;

(e) outages caused by Adverse Weather or Major Storm Disasters which result in the declaration by the government of a state of calamity in the franchise area of the Distributor; and

(f) outages due to other events that ZERA shall approve after due notice and hearing.

3.4.3 Submission of Distribution Reliability Reports and Performance Targets

3.4.3.1 The Distributor shall submit every three (3) months the monthly Interruption reports for its Distribution System using the standard format prescribed by ZERA.

3.4.3.2 ZERA shall set the performance targets for each Distribution System.

3.5 SYSTEM EFFICIENCY STANDARDS FOR DISTRIBUTORS

3.5.1 System Loss Classifications

3.5.1.1 System Loss shall be classified into two categories: Technical Loss and Non-Technical Loss, and Administrative Loss.

3.5.1.2 The Technical Loss shall be the aggregate of conductor loss, the core loss in transformers, and any loss due to technical metering error.

3.5.1.3 The Non-Technical Loss shall be the aggregate of the Energy lost due to pilferage, meter-reading errors, and meter tampering.

3.5.1.4 The Administrative Loss shall include the Energy that is required for the proper operation of the Distribution System and any unbilled Energy for community-related activities.

3.5.2 System Loss Cap

3.5.2.1 The Distributor shall identify and report separately to ZERA the Technical and Non-Technical Losses in its Distribution System.

3.5.2.2 ZERA shall, after due notice and hearing, prescribe a cap on the System Loss that the Distributor can pass on to its End-Users. Separate caps shall be set for the Technical and Non-Technical Losses.

3.5.2.3 The Distributor shall submit to ZERA an application for the approval of its Administrative Loss. The allowance for Administrative Loss shall be approved by ZERA.

3.5.3 Power Factor at the Connection Point

3.5.3.1 All Users of the Distribution System shall maintain a Power Factor of not less than 90 percent lagging at the Connection Point.

3.5.3.2 The Distributor may establish penalties for User Power Factors that are less than a specified target level, and incentives for User Power Factors that are greater than the target level.

3.5.3.3 The Distributor shall correct feeder and substation feeder bus Reactive Power Demand to a level, which will economically reduce feeder loss.

3.6 CUSTOMER SERVICE STANDARDS FOR DISTRIBUTORS

3.6.1 Customer Service Standards

3.6.1.1 The Customer Service Standards for Distributors shall be:

(a) guaranteed standards; and

(b) overall standards.

3.6.1.2 Guaranteed Standards shall refer to the Customer Services where a penalty is imposed on the Distributor for failing to meet the target level of performance. The penalty is given to the affected Customer.

3.6.1.3 Overall Standards shall refer to the Customer Services where it is not appropriate to give a guarantee, but where the Customers have a right to expect the Distributor to deliver a reasonable level of service.

3.6.2 Measuring Customer Service Performance

3.6.2.1 The evaluation of the Customer Service performance of the Distributor shall include:

(a) prescriptive approach; and

(b) customer rating approach.

3.6.2.2 In the Prescriptive Approach, the Distributor shall file an application with ZERA for the approval of its Customer Service Program including the specified levels of performance or targets.

3.6.2.3 In the Customer Rating Approach, the Distributor shall commission an independent entity, accredited by the ZERA, to conduct a Transactions Survey.

3.6.3 Customer Service Standards for Distributors

3.6.3.1 The Distributor shall submit to ZERA for approval the target levels for the Customer Services listed in Section 3.7. The Distributor shall justify the basis for the target levels of performance.

3.6.3.2 The Distributor shall be evaluated annually to compare its actual performance with the targets.

SECTION 4 - DISTRIBUTION PLANNING CODE

4.1 PURPOSE AND SCOPE

4.1.1 Purpose

(a) to specify the responsibilities of the Distributor, the Distribution System Users in planning the development of the Distribution System;

(b) to specify the technical studies and planning procedures that will ensure the safety and reliability of the Distribution System;

(c) to specify the planning data required for a User seeking a new or a modification of an existing connection to the Distribution System; and

(d) to specify the data requirements to be used by ZETDC in planning the development of the Distribution System.

4.1.2 Scope of Application

This Section applies to all Distribution System Users including:

(a) ZETDC;

(b) embedded Generators;

(c) Users; and

(d) any other User System connected to the Distribution System.

4.2 DISTRIBUTION PLANNING RESPONSIBILITIES AND PROCEDURES

4.2.1 Distribution Planning Responsibilities

4.2.1.1 ZETDC shall be responsible for Distribution Planning, including:

(a) analysing the impact of the connection of new facilities such as Embedded Generating Plants, Loads, distribution lines, or substations;

(b) planning the expansion of the Distribution System to ensure its adequacy to meet forecasted Demand and the connection of new Embedded Generating Plants; and

(c) identifying and correcting problems on Power Quality, System Loss, and Reliability in the Distribution System.

4.2.1.2 The Users of the Distribution System, including Embedded Generators, Large Customers, and other entities that have a System connected to the Distribution System shall cooperate with ZETDC in maintaining a Distribution Planning data bank.

4.2.2 Submission of Planning Data

4.2.2.1 Any User applying for connection or a modification of an existing connection to the Distribution System shall submit to ZETDC the relevant Standard Planning Data specified in Section 4 and the Detailed Planning Data in accordance with the requirements prescribed.

4.2.2.2 All Users shall submit annually to the Distributor the relevant historical planning data for the previous year and the forecast planning data for the five (5) succeeding years. These shall include the updated Standard Planning Data and the Detailed Planning Data.

4.2.2.3 The required Standard Planning Data specified in Section 4.4 shall consist of information necessary for the Distributor to evaluate the impact of any User Development on the Distribution System.

4.2.2.4 The Detailed Planning Data specified in Section 4.5 shall include additional information necessary for the conduct of a more accurate Distribution Planning study. This shall cover circuit parameters, switchgear, and protection arrangements of equipment directly connected to or affecting the Distribution System. The data shall be adequate to enable the Distributor to assess any implication associated with the Connection Points.

4.2.2.5 The Standard Planning Data and Detailed Planning Data shall be submitted by the User to the Distributor according to the following:

(a) forecast data;

(b) estimated equipment data; and

(c) registered equipment data.

4.2.2.6 The Forecast Data shall contain the User's best estimate of the data, including Energy and Demand, being projected for the five (5) succeeding years.

4.2.2.7 The Estimated Equipment Data shall contain the User's best estimate of the values of parameters and information pertaining to its Equipment.

4.2.2.8 The Registered Equipment Data shall contain validated actual values of parameters and information about the User's Equipment, which are part of the Connected Project Planning Data submitted by the User to the Distributor at the time of connection.

4.2.3 Consolidation and Maintenance of Planning Data

4.2.3.1 The Distributor shall consolidate and maintain the Distribution planning data according to the following categories:

(a) forecast data;

(b) estimated equipment data; and

(c) registered equipment data.

4.2.3.2 If there is any change to its planning data, the customer shall notify ZETDC of the change as soon as possible. The notification shall contain the time and date when the change took effect, or is expected to take effect, as the case may be. If the change is temporary, the time and date when the data is expected to revert to its previous registered value shall also be indicated in the notification.

4.2.4 Evaluation of Proposed Development

4.2.4.1 The Distributor shall conduct Distribution Impact Studies to assess the effect of the proposed User Development on the Distribution System and the System of other Users.

4.2.4.2 The Distributor shall notify the User of the results of the Distribution Impact Studies.

4.2.4.3 The Distributor shall also notify the User of any planned development in the Distribution System that may have an impact on the User System.

4.2.5 Preparation of Distribution Development Plan

4.2.5.1 The Distributor shall collate and process the planning data submitted by the Users into a cohesive forecast and use this in preparing the data for the Distribution Development Plan (DDP).

4.2.5.2 The Distributor shall develop and submit annually to ZERA a Distribution Development Plan.

4.2.5.3 The Distribution Development Plan shall include:

(a) energy and demand forecasts;

(b) distribution substation siting and sizing;

(c) distribution feeder routing and sizing;

(d) distribution reactive power compensation plan;

(e) other distribution reinforcement plans; and of the technical and economic analysis performed to justify the DDP.

4.2.5.4 If a User believes that the cohesive forecast prepared by the Distributor does not accurately reflect its assumptions on the planning data, it shall promptly notify the Distributor of its concern. The Distributor and the User shall promptly meet to address the concern of the User.

4.3 DISTRIBUTION PLANNING STUDIES

4.3.1 Distribution Planning Studies to be Conducted

4.3.1.1 The Distributor shall conduct Distribution planning studies to ensure the safety and Reliability of the Distribution System for the following:

(a) preparation of the Distribution Development Program to be submitted annually to ZERA;

(b) evaluation of Distribution System reinforcement projects; and

(c) evaluation of any proposed User Development, which is submitted in accordance with an application for a Connection Agreement or an Amended Connection Agreement.

4.3.1.2 The Distribution planning studies shall be conducted to assess the impact on the Distribution System or to any User System of any Demand Forecast or any proposed Equipment change in the Distribution System or the User System and to identify corrective measures to eliminate the deficiencies in the Distribution System or the User System.

4.3.1.3 The relevant technical studies described in this section and the required planning data shall be used in the conduct of the Distribution Planning studies.

4.3.1.4 The Distributor shall conduct distribution planning analysis which shall include:

(a) the determination of optimum patterns for the selection of sites and sizes of distribution substation;

(b) the determination of optimum patterns for feeder development;

(c) the development of optimum Reactive Power compensation programs; and

(d) the development of an optimum feeder configuration and switching controls for distribution feeders.

4.3.1.5 The Distribution planning studies shall be performed using life cycle costing methods. The cost of capital and the discount rate used in such analysis shall be prescribed by the ZERA.

4.3.2 Voltage Drop Studies

4.3.2.1 Voltage drop Studies shall be performed to determine the voltages at the Connection Points for the forecasted Demand of the existing Distribution System and any planned expansion, reinforcement, or development.

4.3.2.2 Voltage drop Studies shall be performed to evaluate the impact on the Distribution System of the connection of new Embedded Generating Plants, Loads, or distribution lines.

4.3.3 Short Circuit Studies

4.3.3.1 Short circuit studies shall be performed to evaluate the effect on the Distribution System Equipment of the connection of new Generating Plants and other facilities that will result in increased fault duties for the Distribution System Equipment. These studies shall identify the Equipment that could be damaged when current exceeds the design limit of the Equipment. The studies shall also identify the Circuit Breakers and fuses, which may fail when interrupting possible short circuit currents.

4.3.3.2 Three-phase short-circuit studies shall be performed for all nodes of the Distribution System for the maximum and minimum generation scenarios of the Distribution System and for different system circuit configurations. Single line-to-ground fault studies shall also be performed for critical Distribution System nodes. These studies shall identify the most severe conditions that the Distribution System Equipment may be exposed to.

4.3.3.3 The Distributor and the User shall exchange information on fault in feed levels at the Connection Point. This shall include:

(a) the maximum and minimum three-phase and line-to-ground fault in feeds;

(b) the X/R ratio under short circuit conditions; and

(c) in the case of interconnected Systems, an adequate equivalent network representation for short circuit calculations.

4.3.3.4 Alternative Distribution System circuit configurations may be studied to reduce the short circuit current within the limits of existing Equipment. The results shall be considered satisfactory when the short-circuit currents are within the design limits of Equipment and the proposed Distribution System configurations are suitable for flexible and safe operation.

4.3.4 System Loss Studies

4.3.4.1 System Loss studies shall be performed to identify, classify, and quantify the losses in the Distribution System. The various categories and components of System Loss specified in Section 3 shall be identified and quantified in conducting the System Loss studies.

4.3.4.2 System Loss studies shall be performed to determine the effects of any User Development and any development in the Distribution System on the efficiency of the Distribution System.

4.3.5 Distribution Reliability Studies

4.3.5.1 Distribution Reliability studies shall be performed to determine the frequency and duration of Customer Interruptions in the Distribution System.

4.3.5.2 The historical Reliability performance of the Distribution System shall be determined from the Interruptions data of the Distribution System.

4.4 STANDARD PLANNING DATA

4.4.1 Energy and Demand Forecast

4.4.1.1 The Customer (Distributing 100kW or more) shall provide the Distributor with its Energy and Demand forecasts at each Connection Point for the five (5) succeeding years if need be.

4.4.1.2 The Forecast Data for the first year shall include monthly Energy and Demand forecasts, while the remaining four years shall include only the annual Energy and Demand forecasts.

4.4.1.3 The Customers shall provide the net values of Energy and Demand forecast after any deductions to reflect the output of a Customer Self-Generating Plant. Such deductions shall be stated separately in the Forecast Data.

4.4.1.4 The following factors shall be taken into account by the Distributor and the Customer when forecasting Demand:

(a) historical demand data;

(b) demand trends;

(c) significant public events;

(d) customer self-generating plant schedules;

(e) demand transfers;

(f) interconnection with adjacent distributors; and

(g) other relevant factors.

4.4.1.5 The Embedded Generator shall submit to the Distributor the projected Energy and Demand to be generated by each Embedded Generating Unit and Embedded Generating Plant.

4.4.2 Embedded Generating Unit Data

4.4.2.1 The Embedded Generator shall provide the Distributor with data relating to the Embedded Generating Units of each Embedded Generating Plant.

4.4.2.2 The following information shall be provided for the Embedded Generating Units of each Generating Plant:

(a) rated capacity (MVA and MW);

(b) rated voltage (kV);

(c) type of generating unit and expected running mode(s);

(d) direct axis subtransient reactance (%); and

(e) rated capacity, voltage, and impedance of the Generating Unit's step-up transformer.

4.4.2.3 If the Generating Unit is connected to the Distribution System at a Connection Point with a bus arrangement which is, or may be operated in separate sections, the bus section to which each Generating Unit is connected shall be identified.

4.4.3 User System Data

4.4.3.1 If the User is to be connected at Low Voltage, the following data shall be provided to the Distributor:

(a) connected loads; and

(b) maximum demand.

4.4.3.2 If the User is to be connected at Medium Voltage or High Voltage, the following data shall be provided to the Distributor:

(a) all types of loads:

(1) connected load, including type and control arrangements;

(2) maximum demand;

(b) Fluctuating and Cyclical Loads:

(1) the rate of change of the demand;

(2) the switching interval; and

(3) the magnitude of the largest step change.

4.4.3.3 The Customer shall provide the Electrical Diagrams and Connection Point Drawings of the User System and the Connection Point, as specified in Sections 2.7 and 2.8, respectively. The diagrams and drawings shall indicate the quantities, ratings, and operating parameters of the following:

(a) equipment (e.g., Generating Unit, power transformer, and Circuit Breaker);

(b) electrical circuits (e.g., overhead lines and underground cables);

(c) substation bus arrangements;

(d) grounding arrangements;

(e) phasing arrangements; and

(f) switching facilities.

4.4.3.4 The User shall provide the values of the following circuit parameters of the overhead lines and/or underground cables from the User's substation to the Connection Point in the Distribution System:

(a) rated and operating voltage (kV);

(b) positive sequence resistance and reactance (ohm);

(c) positive sequence shunt susceptance (Siemens or ohm-1);

(d) zero sequence resistance and reactance (ohm); and

(e) zero sequence susceptance (Siemens or ohm-1).

4.4.3.5 If the User System is connected to the Distribution System through a step up transformer, the following data for the power transformers shall be provided:

(a) rated MVA

(b) rated voltages (kV);

(c) winding arrangement;

(d) positive sequence resistance and reactance (at max, min, and nominal tap);

(e) zero sequence reactance for three-legged core type transformer;

(f) tap changer range, step size and type (on-load or off-load); and

(g) basic Lightning Impulse Insulation Level (kV).

4.4.3.6 The User shall provide the following information for the switchgear, including circuit breakers, load break switches, and disconnect switches at the Connection Point and at the substation of the User:

(a) rated voltage (kV);

(b) rated current (A);

(c) rated symmetrical RMS short-circuit current (kA); and

(d) basic Lightning Impulse Insulation Level (kV).

4.4.3.7 The User shall provide the details of its System Grounding. This shall include the rated capacity and impedances of the Grounding Equipment.

4.4.3.8 The User shall provide the data on independently-switched Reactive Power compensation Equipment at the Connection Point and at the substation of the Customer. This shall include the following information:

(a) rated capacity (MVAR);

(b) rated voltage (kV);

(c) type (e.g., shunt inductor, shunt capacitor, static var compensator); and

(d) operation and control details (e.g. fixed or variable, automatic, or manual).

4.4.3.9 If a significant portion of the User's Demand may be supplied from an alternative Connection Point, the relevant information on the Demand transfer capability shall be provided by the User including the following:

(a) the alternative Connection Point;

(b) the demand normally supplied from each alternative Connection Point;

(c) the demand which may be transferred from or to each alternative connection point; and

(d) the control (e.g. manual or automatic) arrangements for transfer including the time required to effect the transfer for forced outage and planned maintenance conditions.

4.4.3.10 If the User has an Embedded Generating Plant and/or significantly large motors, the short circuit contributions of the Embedded Generating Units and the large motors at the Connection Point shall be provided by the User. The short circuit current shall be calculated in accordance with the IEC Standards or their equivalent national standards.

4.5 DETAILED PLANNING DATA

4.5.1 Embedded Generating Unit and Embedded Generating Plant Data

4.5.1.1 The following additional information shall be provided for the Embedded Generating Units of each Generating Plant:

(a) derated capacity (MW) on a monthly basis if applicable;

(b) additional capacity (MW) obtainable from Generating Units in excess of Net Declared Capacity;

(c) minimum stable loading (MW);

(d) reactive power capability curve;

(e) stator armature resistance;

(f) direct axis synchronous, transient, and sub transient reactances;

(g) quadrature axis synchronous, transient, and sub transient reactances;

(h) direct axis transient and sub transient time constants;

(i) quadrature axis transient and sub transient time constants;

(j) turbine and Generating Unit inertia constant (MWsec/MVA);

(k) rated field current (amps) at rated MW and MVAR output and at rated terminal voltage; and

(l) short circuit and open circuit characteristic curves.

4.5.1.2 The following information on Step-up Transformers shall be provided for each Embedded Generating Unit:

(a) rated MVA;

(b) rated Frequency (Hz);

(c) rated voltage (kV);

(d) voltage ratio;

(e) positive sequence reactance (maximum, minimum, and nominal tap);

(f) positive sequence resistance (maximum, minimum, and nominal tap);
(g) zero sequence reactance;
(h) tap changer range;
(i) tap changer step size; and
(j) tap changer type: on load or off circuit.

4.5.1.3 The following excitation control system parameters shall be submitted:

(a) DC gain of Excitation Loop;
(b) rated field voltage;
(c) maximum field voltage;
(d) minimum field voltage;
(e) maximum rate of change of field voltage (rising);
(f) maximum rate of change of field voltage (falling);
(g) details of Excitation Loop described in diagram form showing transfer functions of individual elements;
(h) dynamic characteristics of over excitation limiter; and
(i) dynamic characteristics of under excitation limiter.

4.5.1.4 The following speed-governing parameters for reheat steam Generating Units shall be submitted:

(a) high pressure governor average gain (MW/Hz);
(b) speeder motor setting range;
(c) speed droop characteristic curve;
(d) high pressure governor valve time constant;
(e) high pressure governor valve opening limits;
(f) high pressure governor valve rate limits;
(g) reheater time constant (Active Energy stored in reheater);
(h) intermediate pressure governor average gain (MW/Hz);
(i) intermediate pressure governor setting range;
(j) intermediate pressure governor valve time constant;
(k) intermediate pressure governor valve opening limits;
(l) intermediate pressure governor valve rate limits;
(m) details of acceleration sensitive elements in high pressure and intermediate pressure governor loop; and
(n) a governor block diagram showing the transfer functions of individual elements.

4.5.1.5 The following speed-governing parameters for non-reheat steam, gas turbine, geothermal, and hydro Generating Units shall be submitted:

(a) governor average gain;
(b) speeder motor setting range;
(c) speed droop characteristic curve;
(d) time constant of steam or fuel governor valve or water column inertia;
(e) governor valve opening limits;
(f) governor valve rate limits; and
(g) time constant of turbine.

4.5.1.6 The following plant flexibility performance data for each Generating Plant shall be submitted:

(a) rate of loading following weekend Shutdown (Generating Unit and Generating Plant);
(b) rate of loading following an overnight Shutdown (Generating Unit and Generating Plant);

(c) block load following synchronizing;

(d) rate of Load Reduction from normal rated MW;

(e) regulating range; and

(f) load rejection capability while still Synchronised and able to supply load.

4.5.1.7 The following auxiliary Demand data shall be submitted:

(a) normal unit-supplied auxiliary load for each Generating Unit at rated MW output; and

(b) each Generating Plant auxiliary Load other than (a) above and where the station auxiliary Load is supplied from the Distribution System.

4.5.2 User System Data

4.5.2.1 Large Customers and other Distributors connected to the Distribution System shall submit to the Distributor the following load characteristics:

(a) maximum demand on each phase at peak load condition;

(b) the voltage unbalance; and

(c) the harmonic content.

4.5.2.2 The Distributor. and the User shall exchange information, including details of physical and electrical layouts, parameters, specifications, and protection, needed to conduct an assessment of transient Over voltage effects in the Distribution System or the User System.

4.5.2.3 The User shall provide any additional planning data that may be requested by the Distributor.

4.5.2.4 ZERA shall randomly inspect rural electrification lines during their construction to check on their quality standards.

SECTION 5 - DISTRIBUTION OPERATIONS & MAINTENANCE CODE

5.1 PURPOSE AND SCOPE

5.1.1 Purpose

(a) to define the operational responsibilities of the Distributor and all Distribution System Users;

(b) to specify the *operational arrangements* for mutual assistance, Equipment and inventory sharing, and joint purchases among Distributors;

(c) to specify the *requirements for communication* and the notices to be issued by the Distributor to Users and the notices to be issued by Users to the Distributor and other Users.

(d) to specify the *maintenance programs* for the Equipment and facilities in the Distribution System;

(e) to describe the *demand control strategies* used for the control of the System Frequency and the methods used for voltage control;

(f) to specify the procedures to be followed by the Distributor and Users during *emergency conditions*;

(g) to specify the *procedures for the coordination, establishment, maintenance, and cancellation of Safety Precautions* when work or testing other than System Test is to be carried out on the Distribution System or the User System;

(h) to specify the *procedures for testing and monitoring* the quality of power supplied to the distribution System and the User System;

(i) to establish a procedure for the conduct of System Tests which involve the simulation of conditions or the controlled application of unusual or extreme conditions that may have an impact on the Distribution System or the User System;

(j) to identify the tests and the procedures that need to be carried out to confirm the compliance of an Embedded Generating Unit with its registered parameters and its ability to provide Ancillary Services; and

(k) to specify the requirements for Site and Equipment Identification at the Connection Point.

5.1.2 Scope of Application

This Section applies to the following:

(a) ZETDC;

(b) other Distributors connected to the Distribution System;

(c) embedded Generators (greater than or equal to one (1) MVA output);

(d) large customers; and

(e) other users.

5.2 OPERATIONAL RESPONSIBILITIES

5.2.1 Operational Responsibilities of the Distributor

5.2.1.1 The Distributor shall be responsible for operating and maintaining Power Quality in the Distribution System during normal conditions, in accordance with the provision of Section 3.2, and in proposing solutions to Power Quality problems.

5.2.1.2 The Distributor is responsible for preparing the Distribution Maintenance Program for the maintenance of its Equipment and facilities.

5.2.1.3 The Distributor is responsible for providing and maintaining all Distribution Equipment and facilities.

5.2.1.4 The Distributor is responsible for designing, installing, and maintaining a distribution protection that will ensure the timely disconnection of faulted facilities and Equipment.

5.2.1.5 The Distributor is responsible for ensuring that safe and economic distribution operating procedures are always followed.

5.2.1.6 The Distributor is responsible for maintaining an Automatic Load Dropping scheme, as necessary, to meet the targets agreed to with the System Operator.

5.2.2 Operational Responsibilities of Embedded Generators

5.2.2.1 The Embedded Generator is responsible for ensuring that its Generating Units can deliver the capabilities declared in its Connection Agreement or Amended Connection Agreement.

5.2.2.2 The Embedded Generator is responsible for providing accurate and timely planning and operations data to the Distributor.

5.2.2.3 The Embedded Generator is responsible for executing the instructions of the Distributor during emergency conditions.

5.2.3 Operational Responsibilities of Other Distribution Users

5.2.3.1 The Customer is responsible for assisting the Distributor in maintaining Power Quality in the Distribution System during normal conditions by correcting any Customer facility that causes Power Quality problems.

5.2.3.2 The Customer shall be responsible for ensuring that its System will not cause any degradation of the Distribution System. It shall also be responsible in undertaking all necessary measures to remedy any degradation that the User System has caused to the Distribution System.

5.2.3.3 The User is responsible for executing the instructions of the Distributor during emergency conditions.

5.3 OPERATIONAL ARRANGEMENTS

5.3.1 Mutual Assistance

5.3.1.1 The Distribution Code Review Panel shall recommend Emergency procedures to ZERA and the Distributors, including the development of a mutual assistance program for Distributors.

5.3.1.2 The Distributors shall cooperate in the establishment of mutual assistance procedures and in providing coordinated responses during emergencies.

5.4 DISTRIBUTION OPERATIONS COMMUNICATIONS, NOTICES AND REPORTS

5.4.1 Distribution Operations Communications

5.4.1.1 The Distributor and the Customer shall establish a communication channel for the exchange of information required for distribution operation. The communication channel shall, as much as possible, be direct between the Distributor and the Customer.

5.4.1.2 If the Distributor decides that a back-up or alternative route of Communication and/ or emergency communication is necessary for the safe operation of the Distribution System, the additional means of communication shall be agreed between the Distributor and the Customer.

5.4.1.3 A list of Accountable Managers and their telephone numbers shall be exchanged between the Distributor and the Customer so that control activities can be efficiently coordinated. The Distributor and the User shall maintain 24- hour availability for these Accountable Managers personnel when necessary.

5.4.2 Distribution Operations Notices

5.4.2.1 A Significant Incident Notice shall be issued by ZETDC or any User if a Significant Incident has transpired on the Distribution System or the System of the User, as the case may be. The notice shall be issued within 15 minutes from the occurrence of the Significant Incident, and shall identify its possible consequences on the Distribution System and/or the System of other customers and any initial corrective measures that were undertaken by the Distributor or the User, as the case may be.

5.4.2.2 A Planned Activity Notice shall be issued by a customer to the Distributor for any planned activity such as a planned Shutdown or Scheduled Maintenance of its Equipment at least three (3) days prior to the actual Shutdown or maintenance.

5.4.3 Distribution Operations Reports

5.4.3.1 The Distributor shall prepare and submit to ZERA monthly reports on distribution operation. These reports shall include an evaluation of the Events and other problems that occurred within the Distribution System for the previous month, the measures undertaken by the Distributor to address them, and the recommendations to prevent their recurrence in the future.

5.4.3.2 The Distributor shall submit to ZERA the Significant Incident Reports prepared pursuant to the provisions of Section 5.7.2.

5.4.3.3 The Distributor shall prepare and submit to ZERA an annual operations report. This report shall include the Significant Incidents on the Distribution System that had a Material Effect on the Distribution System or the System of any User.

5.5 DISTRIBUTION MAINTENANCE PROGRAM

5.5.1 Incident reports

5.5.1.1 Preparation of Maintenance Program

5.5.1.1.1 The Distributor shall prepare the following Distribution Maintenance Programs based on forecasted Demand, User's provisional Maintenance Program, and requests for maintenance schedule:

(a) three-year maintenance program;

(b) annual maintenance program; and

(c) monthly maintenance program;

5.5.1.1.2 The three-year Maintenance Program shall be prepared annually for the three (3) succeeding years. The annual Maintenance Program shall be developed based on the maintenance schedule for the first year of the three year Maintenance Program. The monthly Maintenance Program shall provide the details required by the System Operator for the preparation of the Grid Operating Program, as specified in the Zimbabwe Grid Code.

5.5.1.1.3 The Distribution Maintenance Program shall be developed taking into account the following:

(a) the forecasted demand;

(b) the Maintenance Program actually implemented;

(c) the requests by Users for changes in their maintenance schedules;

(d) the requirements for the maintenance of the Distribution System;

(e) the need to minimize the total cost of the required maintenance; and

(f) any other relevant factor.

5.5.2 Submission and Approval of Maintenance Program

5.5.2.1 The User shall provide the Distributor during the current year a provisional Maintenance Program for the three (3) succeeding years. The following information shall be included in the User's provisional Maintenance Program or when the User requests for a maintenance schedule for its System or Equipment:

(a) identification of the Equipment and the MW capacity involved;

(b) reasons for the maintenance;

(c) expected duration of the maintenance work;

(d) preferred start date for the maintenance work and the date by which the work shall have been completed; and

(e) if there is flexibility in dates, the earliest start date and the latest completion date.

5.5.2.2 The Maintenance Program submitted by the Embedded Generator for its Scheduled Generating Units shall be submitted by the Distributor to the Grid Owner by week 27 pursuant to the requirement of the Zimbabwe Grid Code.

5.5.2.3 The Distributor shall endeavour to accommodate the User's request for maintenance schedule at particular dates in preparing the Distribution Maintenance Program.

5.5.2.4 The Distributor shall provide the User a written copy of the User's approved Maintenance Program.

5.5.2.5 If the User is not satisfied with the Maintenance Schedule allocated to its Equipment, it shall notify the Distributor to explain its concern and to propose changes in the Maintenance Program. The Distributor and the User shall discuss and resolve the problem. The Maintenance Program shall be revised by the Distributor based on the resolution of the Customer's concerns.

5.6 DEMAND AND VOLTAGE CONTROL

5.6.1 Demand Control Coordination

5.6.1.1 The Distributor shall implement Demand Control when the System Operator has issued a Red Alert notice due to a generation deficiency in the Grid or when a Multiple Outage Contingency resulted in Island Grid operation.

5.6.1.2 The Demand Control to be implemented by the Distributor shall include the following:

(a) automatic load dropping;

(b) manual load dropping;

(c) demand disconnection initiated by users; and

(d) voluntary load curtailment.

5.6.1.3 If the System Operator has issued an instruction to implement Demand Control for the Security of the Grid, the Distributor shall promptly implement the instruction of the System Operator.

5.6.1.4 If the Demand Control is to be undertaken by the Distributor to safeguard its Distribution System, the Distributor shall coordinate the Demand Control with the affected Users.

5.6.1.5 The Distributor shall abide by the instruction of the System Operator with regard to the restoration of Demand. The restoration of Demand shall be achieved as soon as possible and the process of restoration shall begin within two (2) minutes after the instruction is given by the System Operator.

5.6.1.6 If a User is disconnected due to Demand Control, the User shall not reconnect its System until instructed by the Distributor to do so.

5.6.2 Automatic Load Dropping

5.6.2.1 The System Operator shall establish the level of Demand required for Automatic Load Dropping in order to limit the consequences of a major loss of generation in the Distribution System. The System Operator shall conduct the appropriate technical studies to justify the targets and/or to refine them as necessary.

5.6.2.2 The Distributor shall prepare its ALD program in consultation with the System Operator. The Distributor's Demand that is subject to ALD shall be split into rotating discrete MW blocks. The System Operator shall specify the number of blocks and the under frequency setting for each block.

5.6.2.3 The under frequency Disconnection scheme shall be designed to allow the Demand Reduction to be uniformly applied throughout the Distribution System, taking into account any operational requirements and essential loads.

5.6.2.4 To ensure that a subsequent fall in frequency will be contained by the operation of ALD, additional Manual Load Dropping shall be implemented by the Distributor so that the loads that were dropped by ALD can be reconnected.

5.6.2.5 The Distributor shall exert best effort to restore immediately the critical facilities included in the ALD program.

5.6.2.6 If an ALD has taken place, the affected User shall not reconnect its disconnected feeder without clearance from the Distributor. The Distributor shall issue the order to reconnect upon instruction by the System Operator.

5.6.3 Manual Load Dropping

5.6.3.1 The Distributor shall make arrangements that will enable it to disconnect its Customers immediately following the issuance by the System Operator of an instruction to implement Manual Load Dropping.

5.6.3.2 The Distributors shall, in consultation with the System Operator, establish a priority scheme for Manual Load Dropping based on equitable load allocation.

5.6.3.3 If the Distributor disconnected a User System, the User shall not reconnect its System until instructed by the Distributor to do so.

5.6.4 Demand Control Initiated by a User

5.6.4.1 If a User intends to implement for the following day Demand Control through a Demand Disconnection at the Connection Point, it shall notify the Distributor of the hourly schedule before 08:30 hours of the current day. The notification shall contain the following information:

(a) the proposed (in the case of prior notification) and actual (in subsequent notification) date, time, and duration of implementation of the Demand Disconnection; and

(b) the magnitude of the proposed reduction by the use of Demand Disconnection.

5.6.4.2 If the Demand Control involves the disconnection of an industrial circuit, Voluntary Load Curtailment (VLC) or any similar scheme shall be implemented wherein the Customers are divided into VLC Weekday groups (e.g. Monday Group, Tuesday Group, etc.). Customers participating in the VLC shall voluntarily reduce their respective Loads for a certain period of time depending on the extent of the generation deficiency. Industrial Customers who implemented a VLC shall provide the Distributor with the amount of Demand reduction actually achieved through the VLC scheme.

5.6.5 Voltage Control

The control of voltage can be achieved by managing the Reactive Power supply in the Distribution System. This shall include the operation of the following Equipment:

(a) synchronous Generating Units;

(b) synchronous condensers;

(c) static VAR compensators;

(d) shunt capacitors and reactors; and

(e) on-load tap changing transformers.

5.7 EMERGENCY PROCEDURES

5.7.1 Preparation for Distribution Emergencies

5.7.1.1 The Distributor shall issue a directive to any User for the purpose of mitigating the effects of the disruption of electricity supply attributable to any of the following:

(a) natural disaster;

(b) civil disturbance; or

(c) fortuitous event.

5.7.1.2 The User shall provide the Distributor, in writing, the telephone numbers of persons who can make binding decisions when there is a Significant Incident.

5.7.1.3 The Distributor shall develop and maintain a Manual of Distribution Emergency Procedures, which lists all parties to be notified, including their business and home phone numbers, in case of an emergency.

5.7.1.4 Emergency drills shall be conducted at least once a year to familiarize all personnel responsible for emergencies. The drills shall simulate realistic emergency situations. A drill evaluation shall be performed and deficiencies in procedures and responses shall be identified and corrected.

5.7.1.5 The User shall participate in all emergency drills organised by the Distributor.

5.7.2 Significant Incident Procedures

5.7.2.1 Following the issuance of a Significant Incident Notice by the Distributor or a User, any User may file a written request to the Distributor for a joint investigation of the Significant Incident. If there have been several Significant Incidents, the joint investigation may include the other Significant Incidents.

5.7.2.2 A joint investigation of the Significant Incident shall be conducted only when the Distributor and the Users have reached an agreement to conduct the joint investigation.

5.7.2.3 The Distributor shall submit a written report to ZERA detailing all the information, findings, and recommendations the Significant Incident.

5.7.2.4 The following minimum information shall be included in the written report following the joint investigation of the Significant Incident:

(a) time and date of the Significant Incident;

(b) location of the Significant Incident;

(c) equipment directly involved and not merely affected by the Event;

(d) description of the Significant Incident; and Demand (in MW) and generation (in MW) interrupted and the duration of the Interruption.

5.7.3 Operation of Embedded Generating Unit in Island Grid

5.7.3.1 If a part of the Distribution System to which an Embedded Generating Unit is connected becomes isolated from the Distribution System, the Distributor shall decide if it is desirable for the Embedded Generating Unit to continue operating.

5.7.3.2 If no facilities exist for the subsequent resynchronisation with the rest of the Distribution System, the Distributor shall issue an instruction to the Embedded Generator to disconnect its Embedded Generating Unit is so that the Island Grid may be reconnected to the rest of the Distribution System.

5.7.4 Black Start and Resynchronisation Procedures

5.7.4.1 If a Significant Incident resulted in a Total System Blackout or a Partial System Blackout and the isolated Distribution System has Embedded Generating Units with Black Start

Capability, the Distributor shall initiate a Black Start procedure upon instruction by the System Operator.

5.7.4.2 The System Operator, pursuant to the procedures in the Zimbabwe Grid Code, shall be responsible in the resynchronisation of the Island Grids after the Black Start procedure or after a Significant Incident has resulted in Island Grid operation.

5.8 SAFETY COORDINATION

5.8.1 Safety Coordination Procedures

5.8.1.1 The Distributor and the User shall adopt and use a set of Safety Rules and Local Safety Instructions for implementing Safety Precautions on MV and HV Equipment. The respective Safety Rules and Local Safety Instructions of the Distributor and the User shall govern any work or testing on the Distribution System or the User System.

5.8.1.2 The Distributor shall furnish the User a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its MV and HV Equipment.

5.8.1.3 The User shall furnish the Distributor a copy of its Safety Rules and Local Safety Instructions relating to the Safety Precautions on its MV and HV Equipment.

5.8.1.4 Any party who wants to revise any provision of its Local Safety Instructions shall provide the other party a written copy of the revisions.

5.8.1.5 Safety coordination procedures shall be established for the coordination, establishment, maintenance, and cancellation of Safety Precautions on MV and HV Equipment when work or testing is to be carried out on the Distribution System or the User System.

5.8.1.6 Work or testing on any Equipment at the Connection Point shall be carried out only in the presence of the representatives of the Distributor and the User.

5.8.1.7 The User (or the Distributor) shall seek authority from the Distributor (or the User) if it wishes to access any Distributor's (or User's) Equipment.

5.8.1.8 If work or testing is to be carried out on the Distribution System and a Safety Precaution is required on the MV and HV Equipment of several Users, the Distributor shall ensure that the Safety Precautions on the Distribution System and on the System of all Users involved are coordinated and implemented.

5.8.1.9 If work or testing is to be carried out on the Distribution System and a User becomes aware that Safety Precautions are also required on the System of other Users, the Distributor shall be promptly informed of the required Safety Precautions on the System of the other Users. The Distributor shall ensure that Safety Precautions are coordinated and implemented on the Distribution System and the Systems of the affected Users.

5.8.2 Safety Coordinator

5.8.2.1 The Distributor and the User shall assign a Safety Coordinator who shall be responsible for the coordination of Safety Precautions on the MV and HV Equipment at their respective sides of the Connection Point. Any party who wants to change its Safety Coordinator shall notify the other party of the change.

5.8.2.2 For purposes of safety coordination, the Safety Coordinator requesting that a Safety Precaution be applied on the System of the other party shall be referred to as the Requesting Safety Coordinator while the Safety Coordinator that will implement the requested Safety Precaution shall be referred to as the Implementing Safety Coordinator.

5.8.2.3 If work or testing is to be carried out on the Distribution System (or the User System) that requires Safety Precautions on the MV and HV Equipment of the User System (or the Distribution System), the Requesting Safety Coordinator shall contact the Implementing Safety Coordinator to coordinate the necessary Safety Precautions.

5.8.2.4 If a Safety Precaution is required for the MV and HV Equipment of other Users who were not mentioned in the request, the Implementing Safety Coordinator shall promptly inform the Requesting Safety Coordinator.

5.8.2.5 If a Safety Precaution becomes ineffective, the concerned Safety Coordinator shall inform the other Safety Coordinators about it without delay stating the reasons why the Safety Precaution has lost its integrity.

5.8.3 Safety Logs and Record of Inter-System Safety Precautions

5.8.3.1 The Distributor and the User shall maintain Safety Logs to record, in chronological order, all messages relating to Safety Coordination. The Safety Logs shall be retained for at least one (1) year.

5.8.3.2 The Distributor shall establish a record of inter-system Safety Precautions to be used by the Requesting Safety Coordinator and the Implementing Safety Coordinator in coordinating the Safety Precautions on MV and HV Equipment. The record of intersystem Safety Precautions shall contain the following information:

(a) site and Equipment Identification of MV or HV Equipment where the Safety Precaution is to be established or has been established;

(b) location and the means of implementation of the Safety Precaution;

(c) confirmation of the Safety Coordinator that the Safety Precaution has been established; and

(d) confirmation of the Safety Coordinator that the Safety Precaution is no longer needed and has been cancelled.

5.8.4 Location of Safety Precautions

5.8.4.1 When work or testing is to be carried out on the Distribution System (or the User System) and Safety Precautions are required on the User System (or the Distribution System), the Requesting Safety coordinator shall contact the concerned Implementing Safety Coordinator to agree on the locations at which the Safety Precautions will be implemented or applied. The Requesting safety Coordinator shall specify the proposed locations at which Isolation and/or Grounding are to be established.

5.8.4.2 In the case of Isolation, the Implementing Safety Coordinator shall promptly notify the Requesting safety Coordinator of the following:

(a) the identification of each Point of Isolation using the Site and Equipment Identification specified in Section 4.12; and

(b) the means of implementing Isolation as specified in Section 5.8.5.

5.8.4.3 In the case of Grounding, the Implementing Safety Coordinator shall promptly notify the Requesting safety Coordinator of the following:

(a) the Identification of each Point of Grounding using the Site and Equipment Identification specified in Section 5.12; and

(b) the means of implementing Grounding as specified in Section 5.8.5.

5.8.4.4 If the Requesting safety Coordinator and the Implementing Safety Coordinator do not agree on the location, Grounding shall be established at the available point on the in-feed closest to the MV and HV Equipment.

5.8.5 Implementation of Safety Precautions

5.8.5.1 Once the locations of Isolation and Grounding have been agreed upon, the Implementing Safety Coordinator shall ensure that the Isolation is implemented.

5.8.5.2 The Isolation shall be implemented by any of the following:

(a) A disconnect switch that is secured in an open position by a lock and affixing a caution Notice to it or by such other method in accordance with the Local Safety Instructions of the Distributor or of the User, as the case may be; or

(b) An adequate physical separation in accordance with the Local Safety Rules of the Distributor or of the User. In addition, a Safety Notice shall be placed at the switching points.

5.8.5.3 The Implementing Safety Coordinator, after the required Isolation in all locations had been established on his System, shall notify the Requesting Safety Coordinator that the required Isolation has been implemented.

5.8.5.4 After the confirmation of Isolation, the Requesting Safety Coordinator shall inform the former of the establishment of relevant Isolation, if any, on his System and request, if required, the implementation of Grounding.

5.8.5.5 The Implementing Safety Coordinator shall ensure the implementation of Grounding and notify the Requesting Safety Coordinator that Grounding has been established on his System.

5.8.5.6 Grounding shall be implemented by any of the following:

(a) A Grounding switch secured in a closed position by a lock and affixing a Caution Notice to it or by such other method in accordance with the Local Safety Instructions of the Distributor or of the User, as the case may be; or

(b) An adequate physical connection (e.g. Grounding Cluster) which is in accordance with the methods set out in the Local Safety Instructions of the Distributor or those of the User. In addition, a safety tag shall be placed at the point of connection and all related switching points.

5.8.5.7 If the disconnect switch or the grounding switch is locked with its own locking mechanism or with a padlock, the key shall be secured in a key cabinet.

5.8.6 Authorisation of Testing

If the Requesting Safety Coordinator wishes to authorize a test on MV or HV Equipment, he shall only do so after the following procedure has been implemented:

(a) confirmation is obtained from the Implementing Safety Coordinator that no person is working on or testing, or has been authorised to work on or test, any part of his System within the Points of Isolation identified , Precautions other than the current Safety Precautions have been cancelled; and

(c) the Implementing Safety Coordinator agrees with him on the conduct of testing in that part of the System.

5.8.7 Cancellation of Safety Precautions

5.8.7.1 When the Requesting Safety Coordinator decides that Safety Precautions are no longer required, he shall contact the Implementing Safety Coordinator and inform him that the Safety Precautions are no longer required.

5.8.7.2 Both shall then cancel the Safety Precautions.

5.9 DISTRIBUTION TESTING AND MONITORING

5.9.1 Testing Requirements

5.9.1.1 The Distributor shall, from time to time, determine the need to test and/or monitor the Power Quality at various points on its Distribution System.

5.9.1.2 The requirement for specific testing and/or monitoring by a Distributor shall be initiated by the receipt of a complaint relating to Power Quality in the Distribution System.

5.9.1.3 In certain situations, the Distributor may require the testing and/or monitoring to take place at the Connection Point of a User to be witnessed by a User representative.

5.9.1.4 If testing and/or monitoring is required at the Connection Point, the Distributors shall advise the User involved and shall make available the results of such tests to the User.

5.9.1.5 Upon the request of the User, a retest shall be carried out. The cost of the retest shall be charged to the User.

5.9.1.6 If the results of the test show that the User is operating outside the technical parameters specified in Sections 5.2.5, 5.2.6, and 5.2.7, the User shall be informed accordingly. The User shall rectify the situation within a period time as agreed upon with the Distributor.

5.9.1.7 If the User failed to rectify the situation, the Distributor may disconnect the User from the Distribution System, in accordance with the Connection Agreement or Amended Connection Agreement.

5.9.2 Monitoring of User Effect on the Distribution System

5.9.2.1 The Distributor shall, from time to time, monitor the effect of the User System on the Distribution System.

5.9.2.2 The monitoring shall normally be related to the amount of Active Power and Reactive Power transferred across the Connection Point.

5.9.2.3 If the User is exporting (or importing) from the Distribution System a Demand in excess of the value specified in the Connection Agreement or Amended Connection Agreement, the Distributors shall inform the User. Upon the request of the User, the Distributor shall demonstrate the results of such monitoring.

5.9.2.4 The User may request technical information on the method of monitoring and, if necessary, request another method that is acceptable to the Distributor.

5.9.2.5 If the User is operating outside the limits specified in Section 3, the User shall immediately restrict the Demand transfer to within the value specified in the Connection Agreement or Amended Connection Agreement. The restriction shall be in effect until a new Amended Connection Agreement is signed and the necessary changes in the Connection Points are undertaken.

5.9.2.6 If the User's Demand is in excess of the rated capacity of the Connection Point, the User shall limit the Demand transfer to the value specified in the Connection Agreement or Amended Connection Agreement.

5.10 SYSTEM TEST

5.10.1 System Test Requirements

5.10.1.1 System Test, which involves the simulation of conditions or the controlled application of unusual or extreme conditions that may have an Impact on the Distribution System or the User System, shall be carried out in a manner that shall not endanger any personnel or the general public.

5.10.1.2 The possibility of damage to Equipment, the Distribution System, and the System of the Users shall be minimised when undertaking a System Test on the Distribution System or the User System.

5.10.1.3 Where the System Test may have an impact on the Grid, the procedure specified in the Zimbabwe Grid Code shall be used in carrying out the proposed System Test.

5.10.2 System Test Request

5.10.2.1 If a User wishes to undertake a System Test on its System, it shall submit to the Distributor a System Test Request that contains the following:

(a) the purpose and nature of the proposed System Test;

(b) the extent and condition of the Equipment involved; and

(c) a proposed System Test Procedure specifying the switching sequence and the timing of the switching sequence.

5.10.2.2 The System Test Proponent shall provide sufficient time for the Distributor to plan the proposed System Test. The Distributor shall determine the time required for each type of System Test.

5.10.2.3 The Distributor may require additional information before approving the proposed System Test if the information contained in the System Test Request is insufficient or the proposed System Test Procedure cannot ensure the safety of personnel and Reliability of the Distribution System.

5.10.2.4 The Distributor shall determine and notify other Users, other than the System Test Proponent, that may be affected by the proposed System Test.

5.10.2.5 The Distributor may also initiate a System Test if it has determined that the System Test is necessary to ensure the safety and Reliability of the Distribution System.

5.10.3 System Test Group

5.10.3.1 If the Distributor is the System Test Proponent, it shall notify all affected Users of the proposed System Test. If the Distributor is not the System Test Proponent, it shall notify, within one (1) month after the acceptance of a System Test Request, the System Test Proponent and the affected Users of the proposed System Test. The notice shall contain the following:

(a) nature of the proposed System Test, the extent and condition of the Equipment involved, the identity of the System Test Proponent, and the affected Users;

(b) an invitation to nominate representatives for the System Test Group to be established to coordinate the proposed System Test; and

(c) if the System Test involves work or testing on MV and HV Equipment, the Safety Coordinators and the safety procedure specified in Section 5.7.8.

5.10.3.2 The Distributor, the System Test Proponent (if it is not the Distributor) and the affected Users shall nominate their representatives to the System Test Group within one (1) month after receipt of the notice from the Distributor.

The Distributor may decide to proceed with the proposed System Test even if the affected Users fail to reply within that period.

5.10.3.3 The Distributor shall establish a System Test Group and appoint a System Test Coordinator, who shall act as chairman of the System Test Group. The System Test Coordinator may come from the Distributor or the System Test Proponent.

5.10.3.4 The members of the System Test Group shall meet within one (1) month after the Test Group is established. The System Test Coordinator shall convene the System Test Group as often as necessary.

5.10.3.5 The agenda for the meeting of the System Test Group shall include the following:

(a) the details of the purpose and nature of the proposed System Test and other matters included in the System Test Request;

(b) evaluation of the System Test Procedure as submitted by the System Test Proponent and making the necessary modifications to come up with the final System Test Procedure;

(c) the possibility of scheduling simultaneously the proposed System Test with any other test and with Equipment Maintenance which may arise pursuant to the Maintenance Program requirements of the Distribution System or the System of the Users; and

(d) the economic, operational, and risk implications of the proposed System Test on the Distribution System, the System of the other Users, and the Scheduling and Dispatch of the Embedded Generating Plants.

5.10.3.6 The Distributor, the System Test Proponent (if it is not the Distributor) and the affected Users (including those which are not represented in the System Test Group) shall provide the System Test Group, upon request, with such details as the System Test Group reasonably requires to carry out the proposed System Test.

5.10.4 System Test Program

5.10.4.1 Within two (2) months after the first meeting and at least one (1) month prior to the date of the proposed System Test, the System Test Group shall submit to the Distributor, the System Test Proponent (if it is not the Distributor), and the affected Users a proposed System Test Program which shall contain the following:

(a) plan for carrying out the System Test;

(b) system Test Procedure to be followed during the test including the manner in which the System Test is to be monitored;

(c) list of responsible persons, including Safety Coordinators when necessary, who will be involved in carrying out the System Test;

(d) an allocation of the testing cost among the affected parties; and

(e) such other matters as the System Test Group may deem appropriate and necessary and are approved by the management of the affected parties.

5.10.4.2 If the proposed System Test Program is acceptable to the Distributor, the System Test Proponent, and the affected Users, the final System Test Program shall be constituted and the System Test shall proceed accordingly. Otherwise, the System Test Group shall revise the System Test Program.

5.10.4.3 If the System Test Group is unable to develop a System Test Program or reach a decision in implementing the System Test Program, the Distributor shall determine whether it is necessary to proceed with the System Test to ensure the safety and Reliability of the Distribution System.

5.10.4.4 The System Test Coordinator shall be notified in writing, as soon as possible, of any proposed revision or amendment to the System Test Program prior to the day of the proposed System Test. If the System Test Coordinator decides that the proposed revision or amendment is meritorious, he or she shall notify the Distributor, the System Test Proponent and the affected Users to act accordingly for the inclusion thereof. The System Test Program shall then be carried out with the revisions or amendments if the System Test Coordinator received no objections.

5.10.4.5 If System conditions are abnormal during the scheduled day for the System Test, the System Test Coordinator may recommend a postponement of the System Test.

5.10.5 System Test Report

5.10.5.1 Within two (2) months or a shorter period as the System Test Group may agree after the conclusion of the System Test, the System Test Proponent shall prepare and submit a System Test Report to the Distributor, the affected Users, and the members of the System Test Group.

5.10.5.2 After the submission of System Test Report, the System Test Group shall be automatically dissolved.

5.10.5.3 The Distributor shall submit the System Test Report to the ZERA for its review and recommendations.

5.11 EMBEDDED GENERATING UNIT CAPABILITY TESTS

5.11.1 Test Requirements

5.11.1.1 Tests shall be conducted, in accordance with the agreed procedures and standards, to confirm the compliance of Embedded Generating Units for the following:

(a) capability of Generating Units to operate within their registered Generation parameters;

(b) capability of the Generating Units to meet the applicable requirements of the Zimbabwe Grid Code and the Distribution Code;

(c) capability to deliver the Ancillary Services that the Generator had agreed to provide; and

(d) availability of Generating Units in accordance with their capability declaration.

5.11.1.2 All tests shall be recorded and witnessed by the authorised representatives of the Distributor, Generator, and/or User.

5.11.1.3 The Generator shall demonstrate to the Distributor the reliability and accuracy of the test instruments and Equipment to be used in the test.

5.11.1.4 The Distributor may at any time issue instructions requiring tests to be carried out on any Embedded Generating Unit. 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 the necessity for further tests.

5.11.1.5 If an Embedded Generating Unit fails the test, the Generator shall correct the deficiency within an agreed period to attain the relevant registered parameters for that Embedded Generating Unit.

5.11.1.6 Once the Generator achieves the registered parameters of its Embedded Generating Unit that previously failed the test, it shall immediately notify the Distributor. The Distributor shall then require the Generator to conduct a retest in order to demonstrate that the appropriate parameter has already been restored to its registered value.

5.11.1.7 If a dispute arises relating to the failure of an Embedded Generating Unit to pass a given test, the Distributor, the Generator, and/or User shall seek to resolve the dispute among themselves.

5.11.1.8 If the dispute cannot be resolved, one of the parties may submit the issue to ZERA.

5.11.2 Tests to be Performed

5.11.2.1 The Reactive Power test shall demonstrate that the Embedded

Generating Unit meets the registered Reactive Power Capability requirements specified in Section 2.4.2. The Embedded Generating Unit shall pass the test if the measured values are within ±5 percent of the Capability as registered with the Grid Owner through the Distributor.

5.11.2.2 The Fast Start capability test shall demonstrate that the Embedded Generating Unit has the capability to automatically Start-Up, synchronize with the Grid through the Distribution System and be loaded up to its offered capability, as specified in Section 2.4. The Embedded Generating Unit shall pass the test if it meets the Fast Start capability requirements.

5.11.2.3 The Black Start test shall demonstrate that the Embedded Generating Plant with Black Start capability can implement a Black Start procedure, as specified in Section 2.4. To pass the test, the Embedded Generating Unit shall start on its own, synchronize with the Grid through the Distribution System and carry load without the need for external power supply.

5.11.2.4 The Declared Data capability test shall demonstrate that the Embedded Generating Unit can be scheduled and dispatched in accordance with the Declared Data. To pass the test, the Embedded Generating Unit shall satisfy the ability to achieve the Declared Data.

5.11.2.5 The Dispatch accuracy test shall demonstrate that the Embedded Generating Unit meets the relevant Generation Scheduling and Dispatch Parameters. The Embedded Generating Unit shall pass the test if:

(a) in the case of synchronisation, the process is achieved within ±5 minutes of the registered synchronisation time;

(b) in the case of synchronizing generation (if registered as a Generation Scheduling and Dispatch Parameters), the synchronizing generation achieved is within an error level equivalent to 2.5% of Net Declared Capacity;

(c) in the case of meeting ramp rates, the actual ramp rate is within ±10% of the registered ramp rate;

(d) in the case of meeting Load reduction rates, the actual Load reduction rate is within ±10% of the registered Load reduction rate; and

(e) in the case of all other Generation Scheduling and Dispatch Parameters, values are within ±1.5% of the declared values.

5.11.2.6 The Ancillary Services acceptability test shall determine the committed services in terms of parameter quantity or volume, timeliness, and other operational requirements. Generators providing Ancillary Services shall conduct the test or define the committed service. However, monitoring by the System Operator or the Distributor of the Ancillary Services performance in response to System-derived inputs shall also be carried out.

5.12 SITE AND EQUIPMENT IDENTIFICATION

5.12.1 Site and Equipment Identification Requirements

5.12.1.1 The Distributor shall develop and establish a standard system for Site and Equipment Identification to be used in identifying any Site or Equipment in all Electrical Diagrams, Connection Point Drawings, distribution operation instructions, notices, and other documents.

5.12.1.2 The identification for the Site shall include and be unique for each substation and switchyard where a Connection Point is located.

5.12.1.3 The identification for Equipment shall be unique for each transformer, distribution line, bus, circuit breaker, disconnect switch, grounding switch, capacitor bank, reactor, lightning arrester, CCPD, and other MV and HV Equipment at the Connection Point.

5.12.2 Site and Equipment Identification Label

5.12.2.1 The Distributor shall develop and establish a standard labelling system, which specifies the dimension, sizes of characters, and colours of labels, to identify the Sites and Equipment.

5.12.2.2 The Distributor or the User shall be responsible for the provision and installation of a clear and unambiguous label showing the Site and Equipment Identification at their respective System.

5.13 INSTALLATION OF STANDBY GENERATORS WITHIN THE DISTRIBUTION NETWORK

5.13.1 This section details the correct method of installing standby generators that provide power to an installation that is normally supplied by the distributors low voltage network.

5.13.2 All generators installed within distribution system Electricity's area of supply shall comply with the requirements of this code. Only 4 pole transfer switches in the case of 3 phase generators and 2 pole transfer switches in the case of single phase generators shall be permitted.

5.13.3 All generators must be earthed in accordance with Electrical (wiring) regulations 1961 of Zimbabwe and the SAZ standard for Electrical wiring of premises (ZWS wiring rules) ZWS 400:2006.

5.13.4 Standby generators shall only be installed by qualified Persons or electricians in accordance with the provisions of the electricity safety regulations and the relevant distributor's safety rules.

5.13.5 The generator manufacturer's safety guidelines shall be adhered to.

5.13.6 Any installed generator shall not run in parallel with the distribution Electricity's supply at any time.

5.13.7 Whenever a generator is installed, a label with the words "DANGER GENERATOR CONNECTED" shall be affixed to the main incoming utility/ distributor Electricity circuit breaker. This label shall be a permanent red label with white lettering at least 10 mm high.

5.13.8 Transfer Switch:

(a) a single phase generator shall be fitted with a 2 pole break-before-make transfer switch that breaks both the phase conductor and neutral conductor simultaneously when the generator is in operation.

(b) a three phase generator shall be fitted with a 4 pole break-before-make transfer switch that breaks the three phase conductors and neutral conductor simultaneously when the generator is in operation.

The transfer switch shall have a fully rated neutral pole (with design, construction, and ampere capacity rating identical to the phase pole).

5.13.9 Breaking the neutral when the generator is in operation prevents the following harmful effects:

(a) fault conditions transferring from the consumer's circuit to the distribution Electricity's circuit which could result in the electrocution of the distributor's Electricity staff or contractors trying to restore supply; and

(b) the consumers earthed neutral being utilised as the system neutral when the system neutral has been stolen. This could result in the consumer's neutral conductor becoming overloaded which could result in fire.

SECTION 6 - DISTRIBUTION METERING CODE

6.1 PURPOSE AND SCOPE

6.1.1 Purpose

(a) to establish the requirements for metering the Active and Reactive Energy and Demand input to and/or output from the Distribution System;

(b) to ensure appropriate procedures for providing metering data for billing and settlement; and

(c) to ensure that a dispute settlement process is established and to quickly and satisfactorily resolve any billing and payment dispute.

(d) to provide information for planning and management decision-making.

6.1.2 Scope of Application

This section applies to all Distribution System Participants including:

(a) ZETDC;

(b) other distributors connected to the Distribution System;

(c) embedded generators;

(d) large customers; and

(e) other users.

6.1.3 Provision of Metering Systems

6.1.3.1 A Distributor shall provide, install and maintain a meter installation for retail billing and settlement purposes for each customer connected to its distribution system.

6.1.3.2 The Distributor shall install maximum demand metering (kVA) for customers with an installed capacity greater than 200kVA.

The Distributor shall provide a check meter to any customer whose installed capacity is 5MVA and above, which shall be connected through independent CTs, VTs and ancillary equipment.

6.1.3.3 The distributor shall identify in its Conditions of Service the types of meters that are available to a customer, the process by which a customer may obtain such meter and the types of charges that would be levied on a customer for each meter type.

6.1.3.4 At all times the distributor shall have its meters sealed at the critical points i.e. Calibration point and Installation point.

6.1.3.5 At no time shall the customer tamper with the meter seals, as this is an offence, which attracts prosecution under the Electricity Act.

6.1.3.6 The distributor shall install only calibrated date-stamped meters and ancillary equipment. The standards used for calibration shall be stated in the test certificates.

6.2 PROVISION OF METERING SERVICES

6.2.1 On request from a customer the distributor shall connect a check meter or carry out in-situ tests to determine the accuracy of the meter. The customer that requests check metering shall compensate the distributor for all incremental costs associated with that meter, or the cost of in -situ test. If it is a check meter, which is installed, it shall be removed from circuit upon conclusion of the matter and the period shall not exceed two calendar months. If it is in-situ test the customer has a right to receive a test certificate of the meter in question.

6.2.2 The distributor shall, for a fee, on a written request, provide maximum demand customers with profile data on written request for demand side management studies. The information shall not be for third parties. Any energy consultants shall receive profile data upon payment of a fee determined at the time of need.

6.2.3 The distributor shall have an inspection and maintenance program for poly-phase metering installations and document the inspection and results of the inspection.

6.2.4 The distributor shall provide metering services and exercise appropriate diligence in detecting and acting upon instances of tampering with metering and service entrance equipment. Upon identification of possible meter tampering, the distributor shall take appropriate action, which may lead to prosecution.

6.2.5 The distributor shall respond to customer metering disputes, and shall establish a fair and reasonable charge for costs associated with resolution of these disputes. If a complaint is substantiated, the charge shall not be applied. In resolving a dispute, the distributor may involve a mutually agreed arbitrator at any time during the dispute resolution process.

6.3 METERING REQUIREMENTS FOR EMBEDDED GENERATORS

6.3.1 The distributor shall install a four-quadrant meter at the interface with an embedded Generator.

6.3.2 The distributor shall require an embedded Generator connected to the distribution system to install its own four-quadrant meter in accordance with the distributor's metering requirements and to provide the technical details of the metering installation.

6.3.3 Where an embedded Generator's metering installation does not conform to measurement standards, the distributor shall require the embedded Generator to have the metering installation, tested and apply an agreed measurement correction factor to meter readings until conformance is achieved.

6.3.4 Where practical, metering for embedded Generators shall be installed at the point of supply. If it is not practical to install the meter at the point of supply, the distributor shall apply loss factors to the generation output in accordance with the loss factors applied for retail settlements and billing.

6.4 METERING REQUIREMENTS AT BULK SUPPLY (ZERA) INTERFACES

6.4.1 The distributor shall install a four-quadrant meter at each and every interface with the transmission network.

6.4.2 ZETDC may install a check meter and the maintenance of such (check meter) equipment shall be the responsibility of ZETDC.

6.4.3 The installed meter shall be synchronised with the distributor's meter.

6.4.4 The installation of the meter shall be at the point of interface practically but in any other case both parties shall agree upon the position.

6.5 METERING DATA MANIPULATION

6.5.1 Metering data collected by the distributor shall be subjected to a validating, estimating and editing (VEE) process if a customer has queried the validity of the electricity bill.

6.5.2 The distributor shall establish a VEE process according to industry practice and provide assurance that correct data is submitted to the settlement process.

6.5.3 The distributor shall document and make available its VEE process and criteria, and allow scrutiny of its process by customers, retailers and the Zimbabwe Electricity Regulatory Commission (ZERA).

6.6 METERING EQUIPMENT STANDARDS

6.6.1 Voltage Transformers

All voltage Transformers shall comply with the IEC Standards or their equivalent national standards for metering and shall have an accuracy class of 0.3 or better. The burden in each phase of the voltage Transformer shall not exceed the specified burden of the said voltage Transformer. It shall be connected only to a revenue meter with a burden that will not affect the accuracy of the measurement.

6.6.2 Current Transformers

All current Transformers shall comply with the IEC Standards or their equivalent national standards for metering and shall have an accuracy class of 0.3 or better. The burden in each phase of the

current Transformer shall not exceed the specified burden of the said current Transformer. It shall be connected only to a revenue meter with a burden that will not affect the accuracy of the measurement. The current transformer's rated secondary current shall be either 1 or 5 amperes. The neutral conductor shall be effectively grounded at a single point.

6.6.3 Meters

The meter shall conform to the type of circuit of the Distribution System where it is connected. The meter shall measure and locally display the kW, kWh, kVAR, kVARh, and cumulative demand with the optional features of time-of-use, maintenance records, and pulse output.

6.6.4 A cumulative record of the parameters measured shall be available on the meter. Bidirectional meters shall have two such records available. If combined Active and Reactive Energy meters are provided, then a separate record shall be provided for each measured quantity and direction. For electronic meters, the loss of auxiliary supply shall not erase these records.

6.6.5 Pulse output shall be provided for each measured quantity. The pulse output shall be from a three-wire terminal with pulse duration of the range 40–80 milliseconds (preferably selectable) and with selective pulse Frequency or rate. The pulse output shall be galvanically isolated from the voltage and current transformers being measured and from the auxiliary supply input terminals.

6.7 OTHER ACCESSORIES

6.7.1 The metering Equipment shall be placed in a cubicle and shall be secured with seals and lock to prevent unauthorised interference with a provision for the register to be visible and accessible for monitoring.

6.7.2 All wiring from the instrument transformers' secondary terminal box to the metering Equipment cubicle shall be placed in a rigid conduit.

6.7.3 The Distributor shall seal all meters. All seals placed or removed on metering System shall be recorded and the records kept by the Distributor.

6.8 METERING EQUIPMENT TESTING AND MAINTENANCE

6.8.1 Instrument Transformer Testing

Test on the Instrument Transformers shall be conducted by the Distributor during the Test and Commissioning stage. The tests shall be carried out in accordance with the practices of the Distributor or an agreed equivalent international standard or guidelines approved by ZERA.

6.8.2 Meter Testing and Calibration

Test and calibration of meters shall be conducted by the Distributor during the Test and Commissioning stage and as the need arises. If both parties cannot agree on the accuracy of the meter, ZERA shall act as arbiter.

6.8.3 Maintenance of Metering Equipment

The Distributor shall maintain all metering Equipment. The Distributor shall keep all test results, maintenance programs, and sealing records..

6.8.3 Traceability of Metering Standard

The Distributor shall ensure that all Equipment used in the measurement of meter accuracy or in the establishment of test condition for the determination of meter accuracy shall be calibrated and traceable to the Standards Association of Zimbabwe or to any reputable international standard body. The traceability shall be carried out in accordance with the guidelines approved by the ZERA.

6.9 METER READING AND METERING DATA

6.9.1 Meter Reading and Recording Responsibility

Meter reading and recording shall be done by the Distributor and the records will be kept at the offices of the Distributor.

6.10 Collection, Processing, and Access to Metering Data

6.10.1 The collection and processing of metering data shall follow the billing and settlement procedure and schedule of the Distributor.

6.10.2 The Distributor shall download Meter data for billing and settlement purposes.

6.10.3 Validation and Substitution of Metering Data

6.10.3.1 The Distributor shall be responsible for the validation of metering data on its System.

6.10.3.2 In principle, check-metering data if available shall be used to validate the metering data provided that the check-metering Equipment conforms to the accuracy requirements set forth by the Distributor.

6.10.3.3 If a check meter is not available or the metering data is missing, then a substitute value shall be prepared by the Distributor using the data validation and substitution method approved by ZERA.

6.11 Storage and Availability of Metering Data

6.11.1 The Distributor shall be responsible for storing the metering data for its energy services for five years. No alteration to the metering data stored in the database shall be permitted.

6.11.2 User meter data is considered to be confidential and cannot be released without the written consent of the User.

6.12 SETTLEMENT AUDIT PROCEDURES

6.12.1 Right to Request Settlement Audit

6.12.2 The Users have the right to request an audit related to its account and the right to choose an independent third party qualified to perform the audit. The Distributor shall cooperate in the auditing process.

6.12.3 Allocation of Audit Cost

The requesting party is responsible for all outside auditor costs unless the Distributor agrees to pay some or all of those costs.

6.12.4 Audit Result

The audit result shall be issued to the Distributor and the Distributor shall issue a response to the audit report, including any adjustment in account billing/payments proposed.

6.12.5 Audit Appeal

If the User disagrees with the Distributor's response to the audit, that response can be appealed to ZERA.

6.13 SETTLEMENT DISPUTE RESOLUTION

6.13.1 Settlement Dispute Resolution Process—First Stage

If the Distributor and the User cannot resolve a settlement dispute, both parties shall document their positions and submit them to their direct supervisors. Those supervisors shall attempt to resolve the dispute.

6.13.2 Settlement Dispute Resolution Process—Second Stage

If no resolution in the dispute is reached at the supervisors' level, the Distributor's position shall prevail. If the User continues to disagree, the issue can, on the User's request be submitted to ZERA. ZERA shall meet with the parties and attempt to reach an agreement between the parties. If agreement is not reached the ZERA shall issue a decision that shall be honoured by both parties.

6.13.3 Settlement Dispute Appeal Process

In rare cases where one party or the other believes that significant error has been made in ZERA's decision, that party can appeal the decision to the High Court.

SECTION 7 - DISTRIBUTION PROTECTION CODE

7.1 INTRODUCTION

This Section specifies the minimum protection requirements as well as typical settings, to ensure adequate performance of the distribution system as experienced by the customers. ZETDC shall at all times install and maintain protection installations that comply with the principles and specifications of this Section.

7.2 OBJECTIVE

The objective of this Protection Code is to define the minimum protection requirements for any equipment connected to the Distribution System. The objective of the Protection Code is to define minimum protection requirements for any system or equipment connected to the Distribution System. This is done in order to:

(a) ensure agreed power quality to customers;

(b) minimise damage to primary plant;

(c) prevent damage to healthy equipment that conducts fault current during faults;

(d) restore supply over the remaining healthy network;

(e) sustain stability and integrity of the distribution system;

(f) limit safety hazard to the power utility personnel and the public.

7.3 GENERAL PRINCIPLES

Protection schemes are generally divided into:

- equipment protection; and
- system protection.

The main functions of equipment protection are to selectively and rapidly detect and disconnect a fault on the protected circuit. The main function of System protection is to respond to a System condition as opposed to a System fault e.g. under frequency, voltage slide, out of step or sub synchronous resonance and undertake appropriate automatic actions to maintain power network integrity.

The protection functions are considered adequate when the protection relays perform correctly in terms of:

- Dependability
- Security
- Speed of operation
- Selectivity
- Sensitivity

All Distribution System users shall ensure correct and appropriate settings of protection to achieve effective, removal of faulty equipment within the clearance time specified in Section 7.6 of this Distribution Code. Protection settings at the Connection Point shall not be altered, or protection bypassed and/or disconnected without consultation and agreement of ZETDC and the User. In the case where protection is bypassed and/or disconnected, by agreement, then the cause must be rectified and the protection restored to normal condition as quickly as possible. If agreement has not been reached the electrical equipment will be removed from service forthwith.

ZERA shall monitor compliance to all matters covered by this section of the Distribution Code and shall design and effect appropriate penalties for enforcing compliance.

7.4 PROTECTION COORDINATION AT THE CONNECTION POINT

ZETDC shall be responsible for co-ordination of protection at the Connection Point and shall investigate any mal-function of protection or other unsatisfactory protection issues at the Connection Point.

Distribution System Users shall take prompt action to correct any protection mal-function.

7.5 TESTING OF PROTECTION EQUIPMENT

ZETDC shall conduct periodic testing of equipment and systems to ensure these are performing to the designed specifications. Periodic tests must be performed within a period of two years. Each Distribution

System User is responsible for tests on own equipment and test results shall be submitted to ZETDC. The tests are to be done as per the test procedures detailed under this Section of the Distribution Code and as specified from time to time by ZETDC.

7.6 FAULT CLEARANCE TIMES

From a stability consideration the maximum fault clearance times for faults on any Distribution System User's system directly connected to the Distribution System, or any faults on the Distribution System itself, are as follows:

Allowable Maximum Clearance Times:

132 kV 160 milliseconds

66 kV 160 milliseconds

33 kV 200 milliseconds

22 kV 200 milliseconds

11 kV 200 milliseconds

Higher voltages have generally faster clearance times because of the critical nature of such faults on the overall system. However, appropriate discrimination should be observed when protection settings are applied. Slower fault clearance times for faults on a Distribution System Users system may be agreed to but only if, in ZETDC's opinion, system conditions allow this.

7.7 GENERATOR PROTECTION REQUIREMENTS

All Generating Units and all associated electrical equipment of the Generator connected to the Distribution System shall be protected by adequate protection so that the Distribution System does not suffer due to any disturbance originating from the Generating Unit. The minimum protection for the generators shall constitute the following:

- Over current and Earth Fault;
- Differential Protection;
- Reverse power protection;
- Over voltage protection;
- Negative phase sequence;
- Field failure.

7.8 SUB TRANSMISSION (132KV AND BELOW) LINES

Sub Transmission feeders shall be protected by a single Distance Protection. Sub Transmission lines protection shall consist of main and back up protection. Main protection shall be a single Distance Protection Relay consisting of three forward zones. The zones are as per Section 7 of the Zimbabwe Grid Code. Back up shall be provided by definite time and inverse definite minimum time (IDMT) Over-Current and Earth Fault Relays. Short feeders should be equipped with additional differential Relays to provide more sensitive protection for high impedance faults. High-speed auto re closing is deemed necessary for stability purposes. However, most sub transmission lines are radial and less critical to system stability. Sub Transmission lines therefore do not necessarily need HSAR, unless specified by ZERA. Three phase delayed Auto Re Closing should therefore be employed on zone 1 faults on the sub transmission system for all faults.

7.9 DISTRIBUTION LINE PROTECTION REQUIREMENTS:

For the purposes of this Distribution Code, Distribution shall refer to all Connection Points at 33kV and below. All 33 kV and 11 kV lines at Connection points shall be provided with a minimum of Over Current and Earth Fault protection with or without directional features as given below.

7.10 PLAIN RADIAL FEEDERS

Non-directional time lag Over Current and Earth Fault Relay with suitable settings to obtain discrimination between adjacent relay stations.

7.10.1 Parallel Feeders/ Ring Feeders:

Directional time lag Over Current and Earth Fault Relays.

7.10.2 Long Feeders/Transformer Feeders

For long feeders (above 5 km) or transformer feeders, the Over Current Relays should incorporate a high set instantaneous element.

7.10.3 Transformer Protection Requirements:

7.11 GENERATING STATION

All windings of Auto Transformers and power transformer of EHV class shall be protected by differential and Balanced Earth Fault (BEF)/ Restricted Earth Fault (REF) Relays. In addition there shall be back up time lag Over Current and Earth Fault protection. For transformers operating in parallel, Back up Over Current and Earth Fault protection shall have a directional feature at the Connection Point. Over Current Earth Fault Relays should incorporate a high set instantaneous element. In addition to electrical protection, gas operated relays, winding temperature protection and oil temperature protection shall be provided.

7.11.1 Distribution system at Connection Point

For smaller transformers of HV class on the Distribution System Differential Protection shall be provided for 10 MVA and above along with back up time lag Over Current and Earth Fault protection (with directional feature for parallel operations).

Transformers of 1.6 MVA and above and less than 10 MVA shall be protected by time lag Over Current, Earth Fault and instantaneous REF relays. In addition all transformers of 1.6 MVA and above shall be provided with gas-operated relays, winding temperature and oil temperature protection.

7.11.2 Over voltage Protection

Over voltages in the system are caused by lightning surges, switching surges and sudden load throw off. Over voltage surges cause possible failure of insulation on transformers, motors and other related electrical equipment.

They also cause possible flashovers on highly stressed points external or internal to equipment.

7.11.3 Protection against Lightning Over voltages

This shall be achieved through the following;

7.11.4 Rod Gaps

These shall be applied across insulator string or bushing insulators. The gap shall be set to allow the breakdown of the insulation medium at voltages above 140% of nominal as specified in the ZERA's Parameter Guidelines for Protection Test Document Number PTOR 020 R 00.

7.11.5 Horn Gaps

These shall be applied above overhead lines or substations to provide effective protection against direct strike on line conductors, towers and substation equipment. Horn Gaps shall be set to provide effective protection against direct strikes on line conductors, towers and substation equipment as specified by ZETDC.

7.11.6 Lightning Masks

These shall be applied above buildings to protect them against direct lightning strikes. All substation buildings shall be provided with lightning masks for protection against direct lightning strikes. The lightning masks shall be designed as specified by ZETDC.

7.11.7 Surge Arrestors

These shall be applied on lines terminating at the substations and on the transformer terminals so that they divert over voltages to earth without causing short circuits. The surge arrestors shall be as specified by ZETDC.

7.11.8 Protection Against Switching Surges at the Connecting Point

7.11.8.1 Where it is recommended through studies shunt reactors and or pre-closing resistors on circuit breakers shall be installed to protect against switching surges.

7.11.8.2 All distribution circuits at the Connection Point shall be equipped with surge suppressors and arrestors to limit over voltages.

7.11.8.3 Protection of Compensating Equipment

7.11.8.4 Protection of Reactors

All reactors shall be protected at the minimum, by Over Current and Earth Fault Protection, Differential Protection, Restricted Earth Fault Protection, Gas operated and temperature relays.

7.11.8.5 Protection of Capacitors

All Capacitors shall be protected by a minimum of Over Current and Earth Fault Relays.

7.11.8.6 Protection of Static Var Compensators

All Static Var Compensators shall be protected by Over Current and Earth Fault Relays.

7.12 SAFETY PROTECTION REQUIREMENTS

7.12.1 Fire Protection

All electrical energised equipment is capable of causing fire if proper usage and handling procedures are not adhered to.

All ZETDC substations and Connection Points should be equipped with appropriate electrical fire extinguishers located at strategic points at each substation. These shall be tested on annual basis.

Fire fighting system shall where appropriate be automatic and in all instances be adequate.

Fireguards should be created and maintained around the perimeter of every substation and connection point.

All fuels capable of causing fire such as petrol and diesel should be stored at sites away from electrical plant in every substation and Connection Point.

Adequate precautions shall be taken and protection shall be provided against fire hazards to all indoor equipment.

7.12.2 Personnel Protection

All personnel that have to carry out any works at the Connection Point or ZETDC Substation shall abide by the ZESA Safety Rules and any other Safety requirements that shall be put in place by ZETDC from time to time. As a protection measure to personnel against electrical hazards the following shall be observed at all times.

7.12.3 Visitors

All visitors to the Connection Point or ZETDC substation shall obtain the relevant authority to enter and sign the Visitor's Live Enclosure Permit before entering.

7.12.4 Equipment Switching

All switching in ZETDC substations shall be carried out by a ZETDC Senior Authorised Person under the recorded Instruction of a ZETDC Controller.

7.12.5 Carrying out Works at the Connection Point

All works at the Connection Point or any part of the ZETDC Network shall be carried out under any of the following ZESA Safety Documents or any document that shall be specified by ZETDC from time to time, depending on the nature of works being carried out:

- Limitation of Access Document
- Permit to Work Document
- Live Line Permit to Work Document

- Sanction for Test Document
- Visitors Live Enclosure Permit

7.13 EARTHING REQUIREMENTS FOR SUBSTATIONS

7.13.1 Earthing Systems

All substations Earthing Systems should have Earth Resistance lower than 0.5 ohms for effective discharge of lightning or over voltages to earth.

The current carrying paths of an Earthing System should have enough capacity to deal with maximum fault current

Earthing Mat shall be provided below ground level and earth electrodes shall be driven into ground at several points and shall be connected to the Earthing Mat to form an Earthing Mesh.

All structures, transformer tanks, breakers, equipment panels shall be connected to this mat by galvanised steel strips.

7.13.1.1 Periodic Checks on Earthing Systems

7.13.1.2 Buried elements of the earthing system should be checked for condition at random points as and when necessary but not exceeding a period of five (5) years.

7.13.1.3 Circuit continuity should be checked between earthing devices and earthed elements. Open circuits and high resistance connections should be investigated and rectified when regular maintenance is being carried out.

7.13.1.4 Earthing resistance should be measured and if more than 0.5 ohms, it should be reduced by the addition of any of the following:

- Sodium Chloride (Common Salt)
- Calcium Chloride
- Sodium Carbonate
- Copper Sulphate
- Charcoal
- Soft Coke

7.14 DATA REQUIREMENTS:

Grid Users shall provide ZETDC with all data concerning Protection in their system that is connected to the Distribution System.

SECTION 8 - FINANCIAL CAPABILITY STANDARDS FOR DISTRIBUTION

8.1 PURPOSE AND SCOPE

8.1.1 Purpose

(a) to specify the financial capability standards for distributors;

(b) to safeguard against the risk of financial non-performance;

(c) to ensure the affordability of electric power supply while maintaining the required quality and reliability; and

(d) to protect the public interest.

8.1.2 Scope of Application

This Section applies to all Distribution System Users.

8.2 FINANCIAL STANDARDS FOR DISTRIBUTORS

8.2.1 Financial Ratios

The following Financial Ratios shall be used to evaluate the Financial Capability of Distribution Utilities:

(a) Leverage Ratios;
(b) Liquidity Ratios;
(c) Efficiency Ratios; and
(d) Profitability Ratios.

8.2.2 Leverage Ratios

8.2.2.1 The Leverage Ratios for the Distributor shall include the following:

(a) debt ratio;
(b) debt-equity ratio; and
(c) interest cover.

8.2.2.2 The Debt Ratio shall measure the degree of indebtedness of financial leverage of the Distribution Utility. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets.

8.2.2.3 The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Distribution Utility cannot pay off interest and principal.

8.2.2.4 The Debt Ratio can also be calculated as the ratio of Long-Term Debt plus Value of Leases plus Equity. Equity is the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

8.2.2.5 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Distribution Utility.

The Debt-Equity Ratio shall be calculated as the ratio of the sum of Long-Term Debt plus Value of Leases to Equity. The Equity shall be the sum of Outstanding Capital Stock, Retained Earnings, and Revaluation Increment.

8.2.2.6 The Debt-Equity Ratio shall be used to compare the financial commitments of creditors relative to those of the Distribution Utility.

8.2.2.7 The Debt-Equity Ratio shall be used as a measure of the degree of financial leverage of the Distribution Utility.

8.2.2.8 The Interest Cover shall measure the ability of the Distribution Utility to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments.

8.2.2.9 The Interest Cover shall also be used as a measure of financial leverage for the Distribution Utility that focuses on the extent to which contractual interest and principal payments are covered by Earnings Before Interest and Taxes plus Depreciation. The Interest Cover is identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.

8.2.3 Liquidity Ratios

8.2.3.1 Liquidity Ratios shall include the following:

(a) financial current ratio; and
(b) quick ratio.

8.2.3.2 The Financial Current Ratio shall measure the ability of the Distribution Utility to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. The Current Assets shall consist of cash and assets that can readily be turned into cash by the Distribution Utility. The Current Liabilities shall consist of payments that the Distribution Utility is expected to make in the near future.

8.2.3.3 The Financial Current Ratio shall be used as a measure of the margin of liquidity of the Distribution Utility.

8.2.3.4 The Quick Ratio shall measure the ability of the Distribution Utility to satisfy its short-term obligations as they become due. The Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities.

8.2.3.5 The Quick Ratio shall be used to measure the safety margin for the payment of current debt of the Distribution Utility if there is shrinkage in the value of cash and receivables. It measures the case with which the Distribution Utility can pay its bills.

8.2.4 Financial Efficiency Ratios

8.2.4.1 Financial Efficiency Ratios shall include the following:

(a) sales-to-assets ratio; and

(b) average collection period.

8.2.4.2 The Sales-to-Assets Ratio shall measure the efficiency with which the Distribution Utility uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year. The higher the Sales-to-Assets Ratio, the more efficiently the assets of the Distribution Utility have been used.

8.2.4.3 The Average Collection Period (ACP) shall measure how quickly other entities pay their bills to the Distribution Utility. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales.

The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. The Daily Sales shall be computed by dividing Sales by 365 days.

8.2.4.4 The Average Collection Period shall be used to evaluate the credit and collection policies of the Distribution Utility.

8.2.4.5 Two computations of the Average Collection Period shall be made:

(a) ACP with government accounts and accounts under litigation; and

(b) ACP without government accounts and accounts under litigation.

8.2.5 Profitability Ratios

8.2.5.1 Profitability Ratios shall include the following:

(a) net profit margin; and

(b) return on assets.

8.2.5.2 The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT – Tax). The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

8.2.5.3 The Net Profit Margin shall be used to measure the percentage of each peso of sales of the Distribution Utility that remains after all costs and expenses have been deducted.

8.2.5.4 The Return on Assets (ROA) shall measure the overall effectiveness of the Distribution Utility in generating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax (EBIT- Tax) to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

8.2.5.5 The Return on Assets shall be used to measure the overall effectiveness of the Distribution Utility in generating profits from their available assets.

8.2.6 Submission and Evaluation

8.2.6.1 The Distributor shall submit to the ZERA true copies of audited balance sheet and financial statement for the preceding year.

8.2.6.2 The Distributor shall submit to the ZERA a profile of customers, indicating the average power consumption for each class of customers for the preceding year.

8.2.6.3 Failure to submit to the ZERA the requirements shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.

8.2.6.4 All submissions shall be certified under oath by a duly authorised officer.

8.3 CERTIFICATION STANDARDS

8.3.1 Prior to the grant of a license, ZERA may require that applicants, who do not plan to collect funds or advanced deposits prior to providing services, to procure a bond or insurance coverage in an amount sufficient to protect customers in the event of default or non-performance by the applicant.

8.3.2 The amount of the bond or insurance shall be based on the number of customers expected to be served and the number of kiloWatt-hours of electricity the applicant expects to supply. Incentives (in terms of reduced deposit requirements) may be given to applicants who have shown outstanding customer service performance, and who have consistently and accurately estimated expected sales.

8.3.3 The applicant shall designate the geographic area (or customer class) it intends to serve.

8.3.4 ZERA shall adopt an annual fee to be charged to all applicants on an annual basis (the amount shall be determined by ZERA and will change from time to time).

8.3.5 Certifications standards apply primarily to applicants who do not plan to collect funds or advanced deposits prior to providing services.

8.3.6 Financial Standards for Billing, Collection, and Profitability

8.3.6.1 The following Financial Ratios shall be used to assess the capability of Distributors to bill, collect from its customers, and earn a satisfactory rate of return on its investment.

(a) leverage ratios:
  (1) debt ratio;
  (2) debt-equity ratio; and
  (3) interest cover;

(b) liquidity ratios:
  (1) current ratio;
  (2) quick ratio;

(c) efficiency ratios:
  (1) sales-to-assets ratio; and
  (2) average collection period;

(d) profitability ratios:
  (1) net profit margin; and
  (2) return on assets.

8.3.6.2 The Debt Ratio shall measure the degree of indebtedness or financial leverage of the Distributor. The Debt Ratio shall be calculated as the ratio of Total Liabilities to Total Assets. The Debt Ratio shall be used to measure the proportion of assets financed by creditors. The risk addressed by the Debt Ratio is the possibility that the Distributor cannot pay off interest and principal.

8.3.6.3 The Debt-Equity Ratio shall indicate the relationship between long-term funds provided by creditors and those provided by the Supplier. The Debt-Equity Ratio shall be calculated as the ratio of Long-Term Debt plus Value of Leases to Equity.

8.3.6.4 The Interest Cover shall measure the ability of the Distributor to service its debts. The Interest Cover shall be computed as the ratio of Earnings Before Interest and Taxes (EBIT) plus Depreciation to Interest plus Principal Payments. The Interest Cover is identical to Debt Service Capability Ratio because principal payments due during the year are included in the denominator of the ratio.

8.3.6.5 The Financial Current Ratio shall measure the ability of the Distributor to meet short-term obligations. The Financial Current Ratio shall be calculated as the ratio of Current Assets to Current Liabilities. The Current Assets shall consist of cash and assets that can readily be turned into cash by the Distributor.

The Current Liabilities shall consist of payments that the Distributor is expected to make in the near future.

8.3.6.6 The Quick Ratio shall measure the ability of the Distributor to satisfy its short-term obligations as they become due; Quick Ratio shall be calculated as the ratio of the sum of Cash, Marketable Securities, and Receivables to the Current Liabilities. The Quick Ratio shall be used to measure the safety margin for the payment of current debt of the Distributor if there is shrinkage in the value of cash and receivables.

8.3.6.7 The Sales-to-Assets Ratio shall measure the efficiency with which the Supplier uses all its assets to generate sales. The Sales-to-Assets Ratio shall be calculated as the ratio of Sales to Average Total Assets. The Average Total Assets shall be determined using the average of the assets at the beginning and end of the year.

8.3.6.8 The Average Collection Period shall measure how quickly customers pay their bills to the Distributor. The Average Collection Period shall be calculated as the ratio of Average Receivables to Daily Sales. The Average Receivables shall be determined using the average of the receivables at the beginning and end of the year. The Daily Sales shall be computed by dividing Sales by 365 days. Average Collection Period shall be computed as:

(a) those with government accounts and accounts under litigation; and

(b) those without government accounts and without accounts under litigation.

8.3.6.9 The Net Profit Margin shall measure the productivity of sales effort. The Net Profit Margin shall be calculated as the ratio of Net Profits After Taxes to Sales. The Net Profits After Taxes shall be computed as Earnings Before Interest and Taxes minus Tax (EBIT – Tax).

8.3.6.10 The Return on Assets shall measure the overall effectiveness of the Supplier in generating profits from its available assets. The Return on Assets shall be calculated as the ratio of Earnings Before Interest and Taxes minus Tax (EBIT – Tax) to the Average Total Assets. The Average Total Assets shall be computed as the average of the assets at the beginning and end of the year.

8.3.7 Organisational and Managerial Resource Requirements

8.3.7.1 As a requisite for providing retail electric service, a Distributor shall have the technical resources to supply continuous electric service to Customers in its service area and the organisational and managerial ability, in accordance with its Customer contracts.

8.3.7.2 The applicant shall provide the following information:

(a) capability to comply with all scheduling, operating, planning, reliability, Customer registration and settlement policies, rules, guidelines, and procedures established by the Grid Owner and System Operator;

(b) capability to comply with 24-hour coordination with control centres for scheduling changes, reserve implementation, curtailment orders, interruption plan and implementation, and telephone number, fax number, and address where its staff can be directly reached at all times;

(c) at least one officer or employee experienced in the retail electric industry, or a related industry;

(d) adequate staffing and employee training to meet all service level commitments;

(e) a Customer Service Program that describes how the Distributor complies with the ZERA's customer protection rules; and

(f) a disclosure of whether the applicant (officer, director, or principal) has been found liable for fraud, theft or larceny, deceit, or violations of any customer protection or deceptive trade laws in any country.

8.3.8 Submission and Evaluation

8.3.8.1 The Distributor shall submit to ZERA true copies of audited balance sheet, income statements, and cash flow statements for the two most recent twelve (12) month periods. These requirements shall be submitted by the applicant upon application for licensing.

8.3.8.2 Within 60 days of complying with the credit standards, the applicant shall file with ZERA a sworn affidavit that demonstrates compliance with this requirement. Such a demonstration of compliance shall include the provision, along with the affidavit, of independent third party documentation verifying the veracity of the information relied upon for compliance.

8.3.8.3 Within 60 days of complying with the financial standards for Customer protection, the applicant shall file with ZERA a sworn affidavit that attests compliance with the minimum-security deposit requirement. Such a demonstration of compliance shall be accompanied by documentation by the bank, insurance company, or any accredited financial intermediary verifying the integrity and validity of the financial instruments relied upon for compliance.

8.3.8.4 Within 60 days of complying with certification standards, the applicant shall file with ZERA a sworn affidavit that attests compliance Such a demonstration of compliance shall be accompanied by documentation from an independent third party verifying the validity of the documents relied upon for compliance.

8.3.8.5 Within 60 days of complying with organisational and managerial resource requirements, the applicant (or Supplier) shall file with ZERA a sworn affidavit that attests compliance with this requirement.

8.3.8.6 The applicant shall inform ZERA of its proposed geographic service area.

8.3.8.7 The applicant shall inform ZERA the type of service agreement it entered with a Distribution Utility whose franchise area the applicant is planning to offer its services. Such an agreement shall include a provision of whether End-Users will be billed separately by the Supplier and Distribution Utility, or will instead receive a consolidated bill from either the Supplier or the Distribution Utility.

8.3.8.8 The Distributor shall submit to ZERA a profile of its customers, indicating the average power consumption for each type of customers for the preceding twelve months. This requirement shall be due on or before May 15 of the current year.

8.3.8.9 Failure to submit the requirements to ZERA, shall serve as grounds for the imposition of appropriate sanctions, fines, penalties, or adverse evaluation.

8.3.8.10 All submissions shall be certified under oath by a duly authorised officer.

SECTION 9 - INFORMATION EXCHANGE CODE

9. 1 INTRODUCTION

The Information Exchange Code defines the reciprocal obligations of parties with regard to the provision of information for the implementation of the Distribution Code.

The information requirements are necessary to ensure non-discriminatory access to the Distribution System and the safe, reliable provision of distribution services.

The information requirements are divided into planning information, operational information and post-dispatch information.

Information criteria specified in the Information Exchange Code are supplementary to the other codes within the Distribution Code.

9.2 INFORMATION EXCHANGE INTERFACE

The parties shall identify the following for each type of information exchange:

- The name, designation and contact details of the person(s) designated by the information owner to be responsible for provision of the information
- The names, contact details of, and the parties represented by persons requesting the information
- The purpose for which the information is required.

9.2.1 Confidentiality of information

9.2.2 Information exchanged between parties governed by this code shall be confidential.

9.2.3 Confidential information shall not be transferred to a third party without the written consent of the information owner. Parties shall observe the proprietary rights of third parties for the purposes of this code. Access to confidential information within the organisations of parties shall be provided as reasonably required.

9.2.4 Parties receiving information shall use the information only for the purpose for which it was supplied.

9.2.5 The information owner may request the receiver of information to enter into a confidentiality agreement before information, established to be confidential, is provided. A pro forma agreement is included in Appendix II.

9.2.5.1 The parties shall take all reasonable measures 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).

9.3 TELEPHONE/FAX

The Distribution System User and ZETDC shall be responsible for the provision and maintenance of no less than one telephone and one fax unit that shall be reserved for operational purposes only, and shall be continuously attended to and answered without undue delay.

ZETDC shall use a voice recorder for historical recording of all operational voice communication with Distribution System Users. These records shall be available for at least one (1) year. ZETDC shall make the voice records of an identified incident in dispute available within a reasonable time after such a request from the Distribution User and/or ZERA.

9.4 ELECTRONIC MAIL

Electronic communication, wherever used shall always be supported by signed hard copies. The data should be in the same format as specified for hard copy transmission.

The exchange of archived data shall preferable be carried out on a computer-to-computer basis communication link.

9.5 SYSTEM PLANNING INFORMATION

9.5.1 Distribution System Users shall provide such information as and when requested by ZETDC for the purposes of planning and developing the Distribution System .The parties shall submit the information to ZETDC without undue delay. Such information may be required so that ZETDC can plan and develop the Distribution System, monitor current and future power system adequacy and performance, and fulfill its statutory or regulatory obligations.

9.5.2 Distribution System User shall submit to ZETDC and to all relevant service providers the relevant information as specified by ZETDC from time to time.

9.5.3 ZETDC may request additional information as and when required.

9.5.4 ZETDC shall keep an updated technical database of the System for purposes of modeling and studying the behavior of the Distribution System.

9.5.5 ZETDC shall provide Distribution System 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 Distribution Code

9.5.6 ZETDC shall make available all the relevant information related to network planning as described in the Distribution Connection Code, Section 2 of this Distribution Code.

9.5.7 Customers shall, upon request to upgrade an existing connection or when applying for a new connection provide ZETDC with information relating to the following:

Table 9.5 Distribution System Planning Requirements for Customers

Connection	Projected or target connecting date
Commissioning	Target commissioning date
Reliability of connection requested	Number of connecting circuits, e.g. one or two feeders, or firm/ non-firm supply required
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 *point of connection* 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 distribution 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 Distribution System User's *intake* substation and to provide an accurate record of the layout of circuits, numbering and nomenclature of equipment and plant.

9.5.8 ZETDC may estimate any Distribution System planning information not provided by the Distribution System user. ZETDC shall take all reasonable steps to reach agreement with the Grid User *on* estimated data items. ZETDC shall indicate to the Distribution System User *any* data items that have been estimated. The obligation to ensure the correctness of data remains with the Distribution System User.

9.5.9 Embedded Generators shall submit to ZETDC all the maintenance planning information detailed in Section 5 of this Distribution Code with regard to each unit at each power station.

9.6 OPERATIONAL INFORMATION

9.6.1 Pre-commissioning studies

Customers 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.)

9.6.2 Commissioning and notification

(a) 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 ZETDC upon notification of such request.

(b) The asset owner shall communicate changes made during an outage to commissioned equipment, to ZETDC before the equipment is returned to service. ZETDC shall keep commissioning records of operational data for the operational life of the plant connected to the Distribution System.

(c) Participants shall give ZETDC notice, as defined in the Operations Code, of the time at which the commissioning tests will be carried out.

9.6.3 General information acquisition requirements

9.6.3.1 Supervisory Control and Data Acquisition (SCADA)

The information exchange shall support data from the SCADA system. The System Operator (ZERA) shall monitor the state of the power system using the data from the remote terminal units (RTU).

The SCADA system shall be used for storage, display and processing of operational real time data. All Distribution System Users and Generating Units shall make available outputs of their respective operational equipment to the data acquisition system or as specified in the connection agreement.

The data collection, storage, monitoring and display center for ZETDC SCADA data shall be The National Control Centre.

9.6.3.2 Generation Operational SCADA data

The Generator Unit shall provide operational information for both real time and recording purposes in relation to each Generating Unit at each Power Station in respect of indications and measurands as follows:

(i) Mwhr
(ii) Voltage
(iii) Frequency
(iv) MW
(v) MVAr

and any other additional data as specified in the connection agreement.

9.6.3.3 Distribution System Operational SCADA data

ZETDC and the Distribution System user shall specify the data characteristics for monitoring electrical supply and load characteristic at each sub-station and connection point. The data shall be used for both real time and recording purposes in relation to each feeder, transformer and compensation device in respect of indications and measurands as follows:

(i) Voltage
(ii) Frequency
(iii) MW
(iv) MVAr
(v) Current

and any other additional data as specified in the connection agreement.

9.6.3.4 Process signals interface to RTU

The interface of the process signals to RTU shall be as specified by ZETDC. The Interface cabinets shall be installed in the Distribution System user's plant and equipment room if required. The provision and maintenance of the wiring and signaling from the Distribution System Users plant and equipment to the interface cable to MDF shall be the responsibility of the Distribution System User.

9.6.4 Measurements and indications to be supplied by the Distribution System Users to ZETDC shall include the formats as specified by ZETDC. Where required signals become unavailable or do not comply with applicable standards for reasons within the control of the provider of the information, such participant shall report and restore or correct the signals and/or indications as soon as reasonable.

9.6.5 ZETDC shall notify the Distribution System User, where ZETDC, acting reasonably and in consultation with the Distribution System User, determines that additional measurements and/ or indications in relation to a Distribution System User plant and equipment are needed to meet a Distribution System requirement. The costs related to the participant's modifications for the additional measurements and/or indications shall be for the account of the providing Distribution System User

9.6.6 On receipt of such notification from ZETDC the Distribution System User shall promptly ensure that such measurements and/or indications are made available at the RTU.

9.6.7 ZETDC and the Distribution System User shall agree on the timeous provision of operational data items as per the relevant Power Purchase Agreement and/or Power Supply Agreement.

9.6.8 Distribution System Users shall jointly verify all measurements and/or indications for functionality and accuracy once every three (3) years, so as to achieve overall accuracy of operational measurements within the limits agreed.

9.6.9 The data formats to be used and the fields of information to be supplied to ZETDC by the Distribution System Users shall be as per the Power Purchase Agreements.

9.6.10 ZETDC shall provide periodic feedback to Distribution System Users regarding the status of equipment and systems installed in the substations where they are connected to the Distribution System. 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.

9.6.11 Plant status reports provided by Distribution System Users will also include contingency plans where applicable.

9.7 UNIT SCHEDULING

9.7.1 Declared Available Capacity

Embedded Generators shall complete and submit to ZETDC the Declared Available Capacity for each generating unit at a period specified by ZETDC under the Power Purchase Agreement. All scheduled and other outages and deratings which prevent some or all of the Dependable Capacity of each unit from being available for dispatch shall be specified. Should the Declared Available Capacity be less than the Dependable Capacity for any generating unit due to a reason other than Scheduled Outage, the embedded generator or any other generator shall explain the reason for the reduction, the action planned to restore the unit to the Dependable Capacity level, and the estimated time required for such restoration.

9.7.2 Statement of Reduction and Re-establishment in Declared Available Capacity

9.7.2.1 Should the embedded generator or any generator become aware of a change in status of any generating units following the submission of the Declared Available Capacity it shall make this status change known immediately to ZETDC by telephone, followed by written confirmation to be received by ZETDC within one hour. The embedded generator or any other generator shall confirm the reduction in Declared Available Capacity, the reason for the reduction, the action planned to restore the Declared Available Capacity to the Dependable Capacity level, and the estimated time required for such restoration.

9.7.2.2 Once the Declared Available Capacity can be increased over the levels stated above this change in status shall immediately be relayed to ZETDC by telephone communication, followed by written confirmation to be received by ZETDC within one hour. ZETDC may then dispatch the affected generating unit at the Declared Available Capacity level.

9.7.3 Scheduled Capacity Requirement

9.7.3.1 ZETDC will notify the embedded generator or any other generator of its Scheduled Capacity requirements for the plant for each hour of the day as per Power Purchase Agreement the embedded generator or any other generator will confirm acceptance and dispatch the plant to the Capacity Schedule specified in the Power Purchase Agreement.

9.7.3.2 Should ZETDC require changing the Scheduled Capacity level of the plant at any time, it shall notify the embedded generator or any other generator of all changes through telephone communication, followed by sending a revised schedule to be received by the embedded generator or any other generator within one hour. the embedded generator will dispatch the plant to the revised Scheduled Capacity requirements as notified by the initial telephone communication.

9.8 DEMAND SCHEDULING

ZETDC reserves the right to load shed should circumstances beyond its control arise. This will be done to ensure system integrity. ZETDC shall as soon as possible give notice of any imminent load dropping that might arise due to plant outages due to maintenance. However for forced outages such notices might not be possible

9.9 DATA STORAGE AND ARCHIVING

The obligation for data storage and archiving shall lie with the information owner.

9.9.1 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.

9.9.2 All the systems must be able to be audited by the ZERA.

9.9.3 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.

9.9.4 The information owner shall keep all hard copy and/or paper-based information for a period of at least five (5) years (unless otherwise specified in the Distribution Code) commencing from the date the information was created.

9.9.5 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.

9.9.6 Parties shall store planning information that is kept electronically for at least five (5) years or for the life of the plant or equipment concerned, whichever is the longer.

9.9.7 ZETDC shall archive operational information, in a historical repository sized for three (3) years' data. This data includes transmission time-tagged status information, change of state alarms, and event messages, hourly scheduling and energy accounting information and operator entered data and actions.

9.9.8 An audit trail of all changes made to archived data should be maintained. This audit trail shall identify every change made, and the time and date of the change. The audit trail shall include both before and after values of all content and structure changes.

9.10 File Transfers

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. 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.

9.11 PERFORMANCE DATA

9.11.1 Generator performance data

9.11.1.1 Embedded Generators shall provide ZETDC monthly with performance indicators in relation to each unit at each power station in respect of availability and reliability as determined from time to time by ZETDC.

9.11.1.2 Embedded Generators shall report significant events, such as catastrophic failures, to the ZERA within one (1) week of occurrence of such event.

9.11.2 Performance Indicators

ZETDC shall make the following Distribution System performance indicators available monthly to the ZERA:

Table 9.11.2 ZETDC Performance Indicators to be submitted to ZERA

Indicator	Performance this month		Performance year to date		Current international performance where applicable
	Actual	Targeted	Actual	Targeted	
Energy sold by tariff class and economic activity					
Number of customers by customer category					
Number of customers (rural and urban)					
Number of new connections by customer category					
Number of electrified social/community services (schools,clinics)					
Households with access to electricity					
Number of employees per customer					
Number of customer complaints					
Change of tenancy effected within 24 hours					
Average waiting period for connection in days					
Number of faults by voltage and by cause					%
Average arrival time at a fault in minutes					
% interruptions restored within 3 hours					
% interruptions restored within 24 hours					
Average waiting period for connection in days					
% customers outside statutory voltage limits					
Minutes lost per connected customer					
Revenue and expenditure data by source and expenditure item					
Average collecting period					
Distribution losses (technical and non-technical)					
Total system losses					
Energy intensities by customer category					
System load factor					

Indicator	Performance this month		Performance year to date		Current international performance where applicable
	Actual	Targeted	Actual	Targeted	
Electrification rates					
KWh/employee					
CAIDI (Customer Average Interruption Duration Index)					
Payroll per employee					
Paid customer but unconnected					
Application waiting period					
Line length by voltage level					
Total transformer installed capacity					
Number of employees per category (managerial, technical etc)					
Sales revenue per employee					
Customers per employee					
Total payroll					
Payroll per employee					
Debt collection days					
Average tariff per customer category					
Electricity costs as a % of total costs by customer category (non residential consumers)					
Cost of electricity as a % of household expenditure					
Magnitude of subsidies					
Monetary value of DSM programmes carried out					
Reduction in energy due to energy efficiency programmes					
Reduction in demand due to demand side management programmes					
Monetary value of renewable energy programmes carried out					
Number of connections from renewable energy sources					
Total number of accidents recorded					
Number of disabling injuries					
Number of fatalities					
Number of incidents involving property damage					

Indicator	Performance this month		Performance year to date		Current international performance where applicable
	Actual	Targeted	Actual	Targeted	
Accident frequency rate					
Accident severity rate					
Line length by voltage level					
Number of faults by cause and voltage level					
Quality of supply					
Parameters					
Over-Voltage events	Voltage				
Under-voltages events	Voltage flicker				
Voltage unbalances	Voltage dips				
Voltage swells	Voltage transients andsurges				
Unplanned interruptions					

FINANCIAL INDICATORS FOR ALL DISTRIBUTORS

Indicator	Performance this month		Performance year to date		Current international performance where applicable
	Actual	Targeted	Actual	Targeted	
Return on sales					
Return on assets					
Return on capital employed-ROCE					
Liquidity Acid Test (Quick ratios) (times)					
-Current ratio (times)					
-Debtor collection days					
Debt management-Debt to equity ratio					
-Debt ratio (%)					
-Debt coverage ratio (times)					
-interest cover (times)					

project. However where actual figures can be obtained use should be made of them in place of this assumption.

10.2.2.1 Electricity Production Cost

The electricity production cost includes cost of generation, and relevant cost on the transmission, sub-transmission and distribution network. These shall be obtained by multiplying the units or kWh generated by the average electricity production costs applicable to the voltage level.

10.2.2.2 Discount Rates

These shall be as stipulated by Government from time to time.

10.2.2.3 Opportunity Costs

Any opportunity costs or loss of revenue due to the implementation of a project must be taken into account during economic analysis. The loss in revenue must be included in the analysis for the project life.

10.2.2.4 Transfer Payments

Sales tax, custom duties, income tax, subsidies and interest on borrowed funds are all regarded as transfer payments in economic analysis and should therefore be ignored as they do not represent direct claims on the country's resources, but merely reflect a transfer of the control over resources within the country.

10.2.2.5 Shadow Pricing

Shadow prices are economic accounting prices specifically estimated to be used in project appraisal to correct for market distortions. Shadow price corrections are most frequently applied on the following type of cost.

10.2.2.6 Foreign exchange (Shadow Exchange Rate)

Because economic analysis is concerned with the real cost of resources, an exchange rate higher than the official rate, i.e. the shadow rate should be used in estimating the foreign exchange value.

10.2.2.7 Economic Life

Depending on the nature of the project, the following economic life should be assumed:

Table 10.2.2.7 Economic Life of Projects

ITEM	EXPECTED LIFE(Years)
Civil Works and Buildings	20-50
General Equipment	20
TRANSMISSION EQUIPMENT	
• Lines	25-45
• cables	35
• electrotechnical	25
• plant and machinery	25
Tools	10
Light Vehicles	5
Heavy Vehicles	5
Office Furniture	5
Office machinery including typewriters	5
Office Equipment including Computers	3
DISTRIBUTION EQUIPMENT	
• lines	25-45
• cables	35
• electrotechnical	25
• plant and machinery	25

10.2.2.7 Benefits

Each benefit arising from the implementation of the project should be captured and put in a different column, e.g. Sales Revenue that is obtained by multiplying the number of units or kWh to be sold by the average tariff applicable for the financial year. In cases where there is more than one stream of benefits these need to be summed up in a separate column for total benefits.

10.2.3 Cost-Benefit Analysis

10.2.3.1 Objective

The objective of cost-benefit analysis is to test the economic viability of the least-cost option that will have been selected. In other words cost-benefit analysis assesses the benefits accruing to the economy as a result of implementing a project.

10.2.3.2 Methodology

Cost-benefit analysis shall be based on a projection of economic costs and benefits over the lifetime of the project.

Once the costs and benefits have been established, a cash flow statement shall be set up for each year in the period of the analysis. The streams of benefit and cost should be discounted using the discount rate that is market based.

10.2.3.3 Discount Factors

These shall be calculated using the formula given below:

1/(1+r)n

Where r is the discount rate as advised from time to time by ZETDC and n is a time variable.

For the base year n = 0 and for the following year it will be 1 (one) until the last year of the project's life.

10.2.3.4 Discount Rate

The discount rate or cost of capital is the rate of interest reflecting the value of money that is used to convert costs and benefit accruing at different times to equivalent values at a common time.

Using the Net Present Value (NPV), Internal Rate of Return (IRR), the Benefit to Cost ratio and the Least Cost Approach the viability of a project should be determined.

10.2.3.5 The Net Present Value (NPV)

The idea behind the NPV technique is that it discounts the cash flows generated by an asset back to the present day. Thus the NPV technique is concerned with the time value of money. The key consideration is on the net present value, which is the net of the initial (original) cost and the present value of all other cash flows. This is as opposed to the present value of the cash flows, which would simply be the sum of the original cash flows in each year.

The NPV shall be calculated as follows:

$$NPV = \frac{\Sigma NCFt}{(1+r)^t} - I_0$$

Discounted cash flows are summed over life of project (N).

$$NPV = CF_1 \times PVIF(K\%, 1year) + CF_2 \times PVIF(K\%, 2\ yrs) + \ldots CF_n \times PVIF(K\%, n\ yrs) - I_0$$

Where

CF_t	=	cash flow in year t
K	=	cost of capital or discount rate
n	=	period of investment
I_0	=	Initial investment

SECTION 10 - PROJECT APRAISAL FRAMEWORK CODE

10.1 INTRODUCTION

The purpose of this code is to provide guidance on how to appraise projects in ZETDC to ensure that only projects that satisfy ZETDC's viability criteria are implemented.

This edition of the appraisal framework unlike the previous edition includes project documentation guidelines and guidelines on the economic and financial analysis of projects to determine whether projects will increase shareholder value/wealth or not. The underlying principles are that:

(i) Money received today can be invested to earn more money at a real rate of interest.

(ii) Inflation erodes purchasing power of money such that money received in the future does not buy the same quantity of goods as money today.

(iii) There is risk that money expected in the future might not be received. This is called default risk.

(iv) There is the risk that the investors might not be able to liquidate the investment into cash at a fair market price. This is called liquidity risk.

The proper carrying out of a project appraisal will ensure that the proper opportunity cost of public money will be undertaken in an environment where projects are competing for scarce public funds.

10.1.1 Project Documentation Guidelines

These guidelines are meant to provide guidance on areas to include when writing up project proposals to ensure that there is clarity and uniformity in presentations. The guidelines presented here are the minimum requirements and are not exhaustive as projects always vary according to what they are meant to address. It is however felt that some of the major topics for any project are covered. Any relevant additional information that helps better the proposal can still be included.

10.1.2 Project Justification

The project justification should include:

- Purpose of the project
- Nature of the project: Either new works, reinforcement/rehabilitation, replacement or expansion
- How the project is going to fit into the infrastructure already in place and future plans
- Corporate strategic issues the project meant to address
- Identification of the needed service or measures to solve the problems being presently encountered
- Identification of options to provide the needed service. Here the planner must provide the full portfolio of available options
- Evaluation of criteria for evaluating options (e.g. reserve margin, voltage limits)
- Analysis of options considering technical, economic, financial and environmental impacts
- Analyzing availability of resources in ZETDC - labour (local skills, expatriate skills), training; financial resources (local and foreign), physical (land, buildings). Any other possible constraints to be addressed here.
- A recommendation to commit resources to the plan, which provides the needed service in the most cost-efficient manner possible, and which balances the interests of customers and ZETDC.
- For the chosen alternative it is necessary to ensure that the costs are current. If any price changes are foreseen (before approval of project) it may be necessary to include a conservative (+-10%) price change contingency.
- Cost – Benefit analysis (Identification of benefits flowing out of the inception of such projects

A simple procedure to identify benefits of projects should involve answering the following questions:

- What is the problem to be addressed?
- How is the problem being addressed now? - status quo
- What costs are associated with the status quo, which would not be incurred with the inception of the project? - These become the benefits or costs saved.

10.1.3 Results of cost/benefit analysis

10.1.3.1 A brief outline of the results of the financial and economic analysis of the recommended least cost option (as carried out in compliance to the procedures set in Section 3.3 of this Distribution Code) shall be contained in the project documentation.

10.1.3.2 The project documentation shall contain a comment on whether the project passes the set approved viability criteria.

10.1.3.3 Projects shall be subjected to sensitivity analysis and the results of such a sensitivity analysis shall constitute project documentation

10.1.4 Conclusions and recommendations

The project documentation shall provide specific recommendation made by the initiator of the proposal, on how the project shall be implemented. Such a recommendation shall have an alternative fall back plan.

10.2 APPRAISAL GUIDELINES

10.2.1 Economic Analysis

10.2.1.1 Purpose

Main purpose of carrying out economic project appraisals to ensure that scarce resources are used to the best advantage of ZETDCO and the country in terms of meeting adequate, safe, reliable, environmentally friendly and least cost energy supplies.

10.2.1.2 Underlying Principles

Economic analysis shall be based on real prices with a view to secure maximum benefit to the society as a whole rather than the utility. In general, all domestic transfers like indirect taxes, duties, and interest on loans, loan repayment, depreciation and subsidies shall be excluded in prices used in economic analysis. Apart from the exclusion of transfers, the economic analysis shall make use of shadow pricing, which corrects for the distortions existing in the market. Such shadow prices shall be for foreign exchange, labour and the discount rate.

10.2.1.3 Cost Parameters

10.2.1.3.1 The cost shall be calculated on an incremental basis, which means that sunk costs should be excluded. Sunk costs are costs already incurred before the analysis of the project.

10.2.1.3.2 The costs should be based on standard prices. The prices shall be availed to any user or ZERA

10.2.1.3.3 Investment or Capital Costs

For projects the capital costs shall be split into two categories, namely foreign and local costs.

10.2.1.3.4 Foreign costs require use of foreign currency to acquire the project inputs (materials, labour & transport), and local costs (also materials, labour & transport) require the use of local currency.

10.2.1.3.5 Foreign costs shall be shadow priced by the shadow price of foreign currency, whilst the labour component shall be further shadow priced by the labour adjustment factor.

10.2.1.3.6 Costs quoted in foreign currencies shall be converted to local currency using the ruling exchange rate at the time of analysis and the assumptions used shall be made available to ZERA and any other User.

10.2.1.3.7 Unless prices are expected to increase before actual implementation (in which case a price contingency would have to be included), no conversion or adjustments are required for these costs.

10.2.1.3.8 Total capital or investment costs shall be obtained by adding the foreign and local portions of costs.

10.2.2 Operation and Maintenance Costs

Annual O & M costs shall be assumed to be 1.5% of capital costs. They shall be obtained by multiplying the total capital investment costs by 1.5% for the lifetime or period of analysis of the

Where future cash flows are an annuity (an equal amount),

NPV = $C^t F \times PVIF A (k\%, n \text{ yrs}) - I_0$

Where CF = annual Cash Flow

PVIFA = present value interest factor of an annuity

The net present value decision criteria are the acceptance of a project with an NPV equal to or *greater than zero* and the rejection of a project with an NPV less than zero. When comparing mutually exclusive projects, the decision criterion is to accept the project with the highest NPV.

10.2.3.6 The Internal Rate of Return (IRR)

Whilst the net present value method provides useful information on project acceptance, the results from different projects need to be compared in conjunction with the internal rate of return (IRR) method.

The IRR is defined as the discount rate, which will result in an NPV of zero.

$0 = CF_1 \times PVIF (IRR\%, 1yr) + CF_2 \times PVIF (IRR\%, 2 \text{ yrs}) + \ldots CF_n \times PVIF (IRR\%, n \text{ yrs}) - I_0$

To find the IRR one has to solve for the discount rate that gives an NPV that is equal to zero.

The IRR decision criteria shall be acceptance of a project with IRR equal or greater than the discount rate used in the analysis and rejection of a project with an IRR less than the cut off discount rate. In the case of comparing projects, the project with the highest IRR should be given top priority if the projects under consideration are otherwise comparable.

10.2.3.7 The Payback Period

The payback period measures the length of time it takes a project to repay its initial capital cost.

The payback period calculation is:

Number of years immediately prior to the year in which the payback period occurs	*PLUS*	The cash flow received during the year to take The total cash flow during the year during which the payback period occurs

Payback Period = Initial Investment/Annual Cash flow (If the project Cash flows are an annuity)

Or

Payback Period = $\left[\quad t \quad \right]$ $\frac{I_0 - Ct}{CF_t + 1}$ *For unequal cash flows*

Where

t = is the last full year in which the cumulative cash flow are less than the initial investment

I_o = the initial investment

$CF_t + 1$ = the cash flow in year t +1

C_t = Cumulative cashflow

The method can be used where on, viable mutually exclusive projects the period of recovery of the initial investment a major consideration. The acceptable payback period can be decided by the company and may depend on the nature of the project and costs involved.

10.2.3.8 Benefit-Cost Ratio

Projects shall be analysed for benefit – cost ratio. This shall be calculated by dividing the total discounted benefits by the total discounted costs.

10.2.3.9 Financial Analysis

All projects shall be financially appraised. The financial analysis of a project estimates the profit accruing to the project-operating entity or to the project participants, whereas economic analysis measures the effect of the project on the national economy. For a project to be economically viable, it must be financially sustainable, as well as economically efficient. If a project is not financially sustainable, economic benefits will not be realised. Financial analysis and economic analysis are therefore two sides of the same coin and complementary.

In financial analysis all expenditures incurred under the project and revenues resulting from it should be taken into account. This form of analysis is necessary to:

- assess the degree to which a project will generate revenues sufficient to meet financial obligations;
- assess the incentives for producers; and
- ensure demand or output forecasts on which the economic analysis is based are consistent with financial charges or available budget resources.

The steps presented below should be followed in undertaking financial analysis of projects.

10.2.3.10 Capital Costs

Costs quoted in foreign currency should be converted to local currency using the exchange rate ruling at the time of the analysis.

When costs are being incurred over a number of years they must be escalated by the relevant inflation index over the period they are being incurred.

Inflation index for base year is equal to 1 (one)
Inflation index for subsequent years = Ifi * (1+R)

Where:

Ifi is inflation index for previous year
R is inflation rate for the year under consideration written in decimal form.
Appendix 1 shows the forecast exchange rates and inflation rates.

10.2.4 Total Capital/Investment Costs

Total capital or investment costs shall be obtained by adding the foreign and local costs.

10.2.4.1 Operating & Maintenance (O & M) Costs

O & M costs shall be obtained by multiplying the total capital/investment costs by 1.5% and then escalating the results by the inflation index for that year e.g. $\Sigma(D1 \ldots Dn) * 0.015 Ifi$.

Where D1..Dn are the capital costs

Ifi is the inflation index for the year under consideration

10.2.4.2 Electricity Production Costs

These shall be obtained by multiplying the units or kWh generated by the average electricity production cost applicable to the voltage level and then escalating using the inflation index for each year.

10.2.4.3 Total Costs

These shall be obtained by the summation of total capital costs, operating and maintenance costs and electricity production costs.

10.2.4.4 Benefits

These vary depending on the nature of project being considered. Each benefit stream should be put in a different column, e.g. sales revenue is obtained by multiplying the

number of units or kWh to be sold in a particular year by the average tariff and then escalated by the inflation index for that year. In cases where there is more than one stream of benefits these need to be summated in the total benefits column.

10.2.4.5 Net Benefits or Net Cash Flows

This is obtained by subtracting the total costs from total benefits.

10.2.4.6 Discount Factors

These are calculated using the formula given below:

1/(1+r)n

where *r* is the discount rate as advised from time to time.

n is the number of years of the project's useful life.

10.2.4.7 Net Present Values

These are obtained by multiplying the respective net benefits or net cash flows by the discount factor for each year of the project's lifetime or period of analysis. The total of this column gives us the NPV.

10.2.4.8 Cumulative Net Present Values

For the first or base year this is obtained by adding the net present value that has been calculated in the previous step (therefore cumulative NPV for first year equals NPV for first year). For subsequent years it is obtained by adding the cumulative net present value of the preceding year and the net present value of that year.

10.2.4.9 Discounted Benefits and Costs

Discounted benefits are obtained by multiplying the total benefits by the respective discount factors while the discounted costs are obtained by multiplying the total costs by the respective discount factors. Each column of the resultant figures needs to be summed.

10.2.5 Internal Rate of Return (IRR)

This is obtained by using the formula below:

@ IRR (I, L5…L24)

Where:

@ is a lotus function,

IRR is the Internal Rate of Return,

I is an imaginary discount rate written in decimal form and usually ranges from 0.1 to 0.9 where 0.1 represent 10% and 0.9 represents 90% but can exceed unity.

(*L5…L24*) represents the net cash flows or net benefits from the first year to the last year of the period of analysis.

10.2.5.1 Benefit-Cost Ratio

This is obtained by dividing the total discounted benefits by the total discounted costs.

10.2.5.2 Assumptions

The following assumptions need to be stated where applicable.

(i) discount rate;

(ii) O & M cost as a percentage of total investment costs;

(iii) average electricity production costs for period under consideration;

(iv) average tariffs for period under consideration;

(v) load growth rate per annum;

(vi) load factor or power factor;

(vii) exchange rate;

(viii) derivation of benefits for support projects.

10.2.5.3 Expected Results

A viable project has to meet the criteria below :

I. At least 18 % internal rate of return (IRR);
II. A benefit-cost ratio of at least 1;
III. A positive net present value (NPV).

10.2.5.4 Environmental Impact Assessment

All distribution projects shall be subjected to Environmental Impact Assessment (EIA). The Environmental Impact assessment shall be as per the Environmental Code developed and amended by ZERA from time to time, but should include the following issues.

10.2.5.5 Major Environmental Issues

The major environmental issues shall be assessed and incorporated in the planning stage as underscored in the following section.

10.2.5.6 Physical/Biological Effects

All distribution projects shall be assessed on their physical and biological effects as follows:

- Pollution (water, soil, air, noise)
- Waste handling, storage and treatment (solid, water borne, gaseous)
- Effect on downstream surface water bodies (water quality, siltation, and change in regime)
- Effect on soil (erosion, compaction, quality)
- Loss or change of local and surrounding ecosystems e.g. cutting trees
- Effect on threatened/protected species
- Effect on protected areas or habitats
- Interference in animal populations (migration, free movement, behavior, breeding)
- Any other physical and/or biological effects that could be of major concern to ZETDC or any segment of society

10.2.5.7 Social Effects

All distribution projects shall be assessed on their social effects as follows:

- Effect on local community's way of life e.g. displacement
- Consultation, participation and support from local community
- Possible resistance to development
- Restriction of traditional access (pathways, religious sites, etc.)
- Threat to traditional cultural sites and artifacts
- Loss of access to traditional natural resources (grazing, firewood, medicines)
- Increased risks to public health (accidents, diseases, deteriorated water supply)
- Any other social effects that could be of major concern to ZERA or any segment of the public

10.2.5.8 Economic Effects

All distribution projects shall be assessed on their economic effects as follows

- Land tenure issues
- Effect on property values
- Permanent loss of land (opportunity cost)
- Effect on household incomes
- Effect of secondary and downstream economic activity

- Sustainability of chosen technology
- Compliance with international conventions/protocols
- Compliance with national policy, law and standards
- Compliance with voluntary standards (SAZ, ISO 9 000, 14 000)
- Any other economic effects that could be of major concern to ZETDC or any segment of society

10.2.5.9 Typical Impacts

During construction and operation of distribution projects and/or infrastructure special care and mitigation measures should be maintained to reduce or eliminate possible physical, social and economic environmental impacts.

10.2.5.10 Physical Impacts

Physical impacts that could arise due to the construction and operation of distribution infrastructure are:

- Damage to cultural resources and sites
- Visual intrusion from equipment and infrastructure
- Soil erosion from disturbed areas
- Degradation of surface water bodies by increase in suspended particulates
- Noise
- Contamination of ground water or surface water
- Soil contamination
- Any other physical impacts that could be of major concern to ZETDC or any segment of society

ZETDC shall put in place management steps to mitigate against negative possible physical impacts arising from the construction and operations of the transmission infrastructure. Such management steps shall include but not necessary limited:

- Ensuring appropriate siting
- Minimizing clearing and blending vegetation
- Ensuring that safety procedures are followed
- Provision of surface drainage to meet quality standards before discharge of damaging effluent
- Cleaning up of spills (chemicals, diesel, oil, etc)
- Avoiding/minimizing penetration of aquifers
- Controlling surface run off
- Selecting appropriate site(s) for solid waste disposal
- Availability of monitoring instruments to be placed at sensitive areas
- Carrying out appropriate surveys prior to disturbance to determine vulnerability of soil erosion
- Utilizing technologies that minimize waste creation
- Minimize pollution at source
- Routine monitoring air quality
- Routine monitoring of water quality in rivers upstream and downstream of discharge point
- Routine monitoring of ground water through boreholes
- Minimizing dust and particulate emissions
- Installation of appropriate pollution abatement devices on diesel equipment to ensure minimal emissions

10.2.5.11 Social Impacts

Social impacts that could arise due to the construction and operation of transmission and subtransmission infrastructure are:

- Disturbance of both humans and wildlife by noise from activities
- Injury/loss of life from accidents
- Competition with local cultures, traditions and life styles
- Increased demands on services and facilities in local communities
- Social and cultural conflicts affect community stability
- Secondary population growth
- Displacement of local communities
- Health problems associated with dust, smoke, STD, HIV, cholera, malaria, dysentery etc
- Development of schools, hospitals and recreational facilities

ZETDC shall put in place management steps to mitigate against negative possible social impacts arising from the construction and operations of the transmission infrastructure. Such management steps shall include but not necessary limited to:

- Minimizing conflict by employing locals where feasible
- Maintaining open dialogue with communities
- Ensuring that affected people are informed in advance and their rights communicated to them. In the event of problems, ensuring that problems are promptly addressed.
- Taking stock of population to be displaced, making an inventory of property loss and giving adequate compensation.
- Liaising with local community to assess their needs and ensuring minimal conflict between employees and the locals.
- Encourage project workers to participate in community affairs and open periodic dialogue with community leaders.
- Ensuring that safety equipment is available at all times.
- Ensuring that sites of cultural significance are demarcated and fenced or catalogued moved and re-sited.
- Ensuring that historical resources are archived or demarcated from the operating site
- Utilizing appropriate dust control measures – waste spraying, wind breaks.

10.2.5.12 Economic Impacts

Economic impacts that could arise due to the construction and operation of transmission and subtransmission infrastructure are:

- Land use conflicts
- Induced development of other economic sectors
- Availability of a ready market for products
- Employment opportunities for local population

ZETDC shall put in place management steps to mitigate against negative possible economic impacts arising from the construction and operations of the transmission infrastructure. Such management steps shall include but not necessary limited to:

- Consulting with local land users in siting access roads and other utilities
- Allowing other land uses on site if they are compatible with the operations.
- Employing as many locals as skills requirements permit
- Encouraging growth of secondary activities like shops, green markets, etc.

SECTION 11 - WAYLEAVES AND SERVITUDES

11.1 OBTAINING WAYLEAVES AND SERVITUDES

A distributor shall place any line or cable above or below ground into, out of or across any land including State land. Wayleaves shall be obtained in compliance with the Electricity Act and relevant regulations.

Property developers shall provide for servitudes for use by the distributor to place lines/cables. This shall be at no cost to the distributor. Land shall also be made available for substations sites and no fees should be levied against the distributor.

Should future subdivisions/consolidations/building/road constructions require alteration/rerouting/ lowering/ exposing/repositioning then the cost shall be borne by the developer/owner.

11.2 CLEARANCE AND MAINTENANCE OF WAYLEAVES AND SERVITUDES

11.2.1 Purpose

This clause provides for the control of trees adjacent to electricity lines. The purpose of this clause is to protect the security of the supply of electricity and the safety of the public.

11.2.2 General Information Notice to Customers

In order to ensure that land owners are aware of their responsibilities and liabilities under this Code, Distributors are required to issue to electricity customers, at least annually, an information notice outlining the dangers of contact between trees and live power lines and the operation of this Code.

11.2.3 Hazard Warning Notice

When a Distributor becomes aware of a tree growing within the specified separation distance of a power line, the Distributor may give a hazard warning notice to the tree owner. The purpose of a hazard warning notice is to warn a tree owner that a tree encroaches a notice zone and must not encroach a growth limit zone. The regulations prescribe the content of the hazard warning notice.

11.2.4 Cut or Trim Notice

If a Distributor becomes aware of a tree encroaching the growth limit it must issue a cut or trim notice. The purpose of a cut or trim notice is to notify a tree owner that a tree encroaches a growth limit zone and must be trimmed. Once a cut or trim notice has been issued, the tree owner must, within prescribed time limits, have the tree cut or trimmed so that it does not encroach on the notice zone.

11.2.5 Debris

If a tree owner is required to have a tree cut or trimmed, the tree owner must remove or tidy any resulting debris in such a way that it does not affect the use or enjoyment of any adjoining land by its owner or occupier. A Distributor is not required to remove debris caused by any cutting or trimming that it undertakes.

11.2.6 Underground Cable Safety

To permit the safe repair or operation of an underground cable, a Distributor may sever and remove any tree roots that are within 1.5 metres of that cable.

11.2.7 Obligation to Remove Danger to Persons or Property from Trees Damaging Lines

A Distributor must, without delay, undertake any necessary work on a tree (including the roots) if the distributor becomes aware that there is immediate danger to persons or property from a line.

11.2.7.1 For the purposes of removing danger to persons or property, a Distributor may cut or trim the tree to the extent necessary to remove the danger.

11.2.7.3 However if the Distributor deems it necessary it may cut or trim the tree so that it no longer encroaches on the Distributor's line.

11.2.8 Liability for Costs

11.2.8.1 When a Distributor undertakes any work to remove a source of immediate danger, the tree owner is liable for the direct costs of that work if the tree owner has failed to abide by the provisions of this Code.

11.2.8.2 A Distributor may claim direct costs from the tree owner where damage to a line arises (directly or indirectly) from a tree owner's failure to comply with the requirements of this Code or with the conditions of an order made by an arbitrator. The costs shall be recovered as a debt due.

11.2.8.3 A Distributor is liable for any costs of remedying any damage caused to a line if the distributor fails to comply with the requirements of this Code, such as the requirement to issue a cut or trim notice when a tree encroaches the growth limit zone.

SECTION 12 – SAFETY

12.1 PUBLIC SAFETY

12.1.1 The Distributor shall follow good practices in operating and maintaining the distribution system and shall also abide by Safety Rules and regulations to ensure maximum safety to the public.

12.1.2 The Distributor shall implement a safety program including training and regularly conducted audits. The program shall include public education and public safety awareness campaigns.

12.2 EMPLOYEES AND EQUIPMENT

12.2.1 The Distributor shall adhere to Zesa Holdings Electrical Safety Rules and any relevant equipment operational safety procedures.

12.2.2 A copy of the Electricity Act (Chapter 13:19) and the Zesa Holdings Electrical Safety Rules shall be kept available for reference in all relevant premises occupied by the Distributor.

12.3 NON-COMPLIANCE WITH THE CODE

Distributor's obligation to remedy: If the licensee breaches this Code, it shall remedy that breach as soon as is practicable.

12.4 NOTIFICATION TO CUSTOMERS

12.4.1 If a licensee becomes aware of its failure to comply with any obligation under the Code, which can reasonably be expected to have a material, adverse impact on a customer, it shall:

12.4.2 Notify each customer likely to be adversely affected by the non-compliance within five business days:

12.4.3 Undertake an investigation of the non-compliance as soon as is practicable;

12.4.4 Advise the customer of the steps the licensee is taking to comply.

12.4.5 If a Distributor becomes aware of a breach of the Distribution Code by a customer, which is not of a trivial nature, the licensee shall notify the customer, in writing, of:

12.4.5.1 Details of the non-compliance and its implications, including any impact on the licensee and other customers;

12.4.5.2 Actions that the customer could take to remedy the non-compliance;

12.4.5.3 A reasonable time period within which compliance shall be demonstrated;

12.4.5.4 Any consequences of non-compliance.

12.5 CUSTOMER'S OBLIGATION TO REMEDY

The customer shall use best endeavours to remedy any non-compliance with this Distribution Code within the time period specified in any notice of non-compliance sent by the Licensee.

12.6 COMPLIANCE PLANS

12.6.1 Statement of Compliance

Within six (6) months from the effectivity of the Distribution Code, Distributors shall submit to ZERA a statement of their compliance with the technical specifications, performance standards, and financial capability standards prescribed in the Distribution Code.

12.6.2 Submission of Compliance Plans

Distributors which do not comply with any of the prescribed technical specifications, performance standards, and financial capability standards shall submit to the ZERA a plan to comply, within three (3) years, with said prescribed technical specifications, performance standards, and financial standards.

12.7 COMPLIANCE WITH THE ZIMBABWE GRID CODE

12.7.1 The Licensee shall comply with the provisions of the Zimbabwe Grid Code in so far as applicable to it.

12.7.2 The Commission may (following consultations with the Transmission Company responsible for the Grid Code) issue directions relieving the licensee of its obligations under paragraph 1 in respect of such parts of the Grid Code and to such extent and subject to such conditions as may be specified in those directions.

APPENDIX I

DEFINITIONS

In this Code the following words and phrases shall, unless more particularly defined in a Section, or Subsection of the Code, have the following meanings:

Accountable Manager: A Senior Authorised Person who is appointed by ZESA according to the ZESA Electrical Safety Rules

Active Energy: The integral of Active Power with respect to time, measured in Watthour (Wh) or multiples thereof. Unless otherwise qualified, the term "Energy" refers to Active Energy.

Active Power: The time average of the instantaneous power over one period of the electrical wave, measured in Watts (W) or the root-mean-square (RMS) or effective value of the voltage and the RMS value of the in- phase component of the current. In a three – phase System, it is the sum of the Active Power of the individual phases.

Apparent Power: The product of the root-mean-square (RMS) or effective value of the current and the root-mean-square value of the voltage. For AC circuits or systems, it is the square root of the sum of the squares of the Active Power and Reactive Power, measured in volt-ampere (VA) or multiples thereof.

Average Receivables: The average of the accounts receivable at the beginning and end of the period.

Average Total Assets: The average total assets at the beginning and end of the period.

Back up Protection: A form of protection that operates independently of the specified Components in the primary protection system. It may duplicate the primary protection or may be intended to operate only if the primary protection fails or temporarily out of service and operates with a time delay.

Backup Reserve: Refers to a Generating Unit that has Fast start capability and can synchronize with the Grid to provide its declared capacity for a minimum period of eight (8) hours. Also called Cold Standby Reserve.

Balanced Three-Phase Voltages: Three sinusoidal voltages with equal frequency and magnitude and displaced from each other in phase by an angle of 120 degrees.

Black Start: The process of recovery from the total system blackout using a Generating Unit with the capability to start and synchronize with the system without an external power supply.

Circuit Breaker: A mechanical switching device, which is capable of making, carrying for a specified time and breaking current under specified abnormal circuit conditions, such as a short circuit.

Cold start: The starting of a generator after a prolonged shutdown period.

Completion Date: The date specified in the connection agreement or amended connection agreement, when the user development is scheduled to be completed and be ready for connection to the Distribution system.

Component: A piece of equipment, a line or circuit, a section of line or circuit, or a group of items. this viewed as an entity for a specific purpose.

Connection Agreement: An agreement between a user and the Distributor (or the Grid Owner), which specifies the terms and conditions pertaining to the connection point in the Distribution System (or the Grid).

Connection Point: The point of connection of the user system or equipment to the Distribution system (for users of the distribution system).

Connection point Drawings: The drawings prepared for each connection point, which indicate the equipment layout, common protection and control, and auxiliaries at the Connection Point.

Control Center: A facility used for monitoring and controlling the operation of the Grid or distribution system.

Customer: Any person or entity supplied with electric service under a contract with the Distributor or Supplier.

Customer Demand Management: The reduction in the supply of electricity to a Customer or disconnection of a customer in a manner agreed upon for commercial purposes, between a customer and its Generator, Distributor or Supplier.

Customer Services: The day- to – day transactions between a Distributor and its Customers including payment of bills, applications for connection/disconnection, and customer complaints. It also includes any activity that the Distributor does to add value or efficiency to these transaction.

Customer Service Program: The totality of the Customer Services offers by a Distributor.

Customer Services Standards: A listing of Customer Services that measure how effectively a Distributor conducts its day-to-day transactions with its Customers. Customer Service Standards are intended to ensure Customer satisfaction.

Daily Sales: Total annual sales divided by 365 days.

Debt Ratio: The ratio of total liabilities to total assets.

Degradation of Distribution System: A condition resulting from use Development or a Distribution System expansion project that has a material effect on the Distribution System or the system of other Users and which can be verified through Distribution Impact studies.

Demand: The Active Power and/or Reactive Power at a given instant or averaged over a specified interval of time, that is actually delivered or is expected to be delivered by an electrical equipment or supply system. It is expressed in Watts (w) and/or VARs and multiples thereof.

Demand Control: A reduction in demand for the control of the Frequency when the Grid is in the Emergency state. This includes Automatic Load Dropping, Manual Distribution Code December 2001 Load Dropping, demand disconnection initiated by users, customer Demand Management, and voluntary Load curtailment.

Demand Forecast: The projected Demand and Active Power related to each connection Point in the Distribution System.

Distribution Code: The set of rules, requirements, procedures, and standards governing Distribution utilities and users in the operation, maintenance and development of their Distribution Systems. It also defines and establishes the relationship of the Distribution systems with the facilities or installations of the parties connected thereto.

Distribution of Electricity: The conveyance of electric power by a Distributor through its Distribution System.

Distribution system: The system of wires and associated facilities belonging to a Distributor, extending between the delivery points on the transmission, sub-transaction system or Generating plant connection and the point of connection to the premises of the End user.

Embedded Generating Plant: A generating plant that is connected to a Distribution system or the System of any User and has no connection to the Grid.

Electrical Diagram. A schematic representation, using standard electrical symbols, which shows the connection of equipment or power System components to each other or to external circuits.

Embedded Generator: A person or entity that generates electricity using an Embedded Generating plant.

End user: A person or entity requiring the supply and delivery.

Fault Clearance Time: The time interval from fault inception until the end of the arc extinction by the circuit breaker.

Financial Efficiency Ratio: A financial indicator that measures the productivity in the entity's use of its assets.

Flicker. The impression of unsteadiness of visual sensation induced by light stimulus whose luminance or spectral distribution fluctuates with time.

Forced outage: An outrage that results from emergency conditions directly associated with a Component requiring that it be taken out of service immediately, either automatically or as soon as switching operations can be performed. Also, an Outage caused by human error or the improper operation of Equipment.

Franchise Area: a geographical area.

Frequency: The number of complete cycles of alternating current or voltage per time, usually measured in cycle per second or Hertz.

Frequency Control: A strategy used the system operator to maintain the Frequency of the Grid within the limits prescribed by the Grid code.

Frequency Variation: The deviation of fundamental System Frequency from its nominal value.

Generating plant: A facility, consisting of one or more Generating units, where electric Energy is produced from some other form of Energy by means of a suitable apparatus.

Grid Owner: The party who owns the Grid and is responsible for maintaining adequate Grid capacity in accordance with the provisions of grid.

Grounding: A conducting connection by which an electrical circuit or equipment to earth or to some conducting body of relatively large extent that services as ground.

Guaranteed Standards: Refer to the customer services by which an electrical circuit or Equipment connected to earth or to some conducting body of relatively large extent that serves as ground.

Harmonics: Sinusoidal voltages and currents having frequencies that are integral multiples of the fundamental frequency.

High Voltage (HV): A voltage level exceeding 650V.

Implementing Safety Coordinator: The Safety Coordinator assigned by the Distributor (or the User) to establish the requested Safety Precautions in the User System (or the Distribution System).

Interest Cover: The ratio of earnings before interest and taxes plus depreciation to interest.

Interruption: The loss of service to a Customer or a group of Customers or other facilities. An interruption is the result of one or more Component Outages.

Interruption Duration: The period from the initiation of an interruption up to the time when electric service is restored.

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

Large Customer: A customer with a demand of at least 300KVA or the threshold value specified by ZERA.

Leverage Ratio: A financial indicator that measures how an entity is heavily in debt.

Liquidity Ratio: A financial indicator that measure the ability of an entity to satisfy its short-term obligations as they become due.

Load: An entity or an electrical or an electrical equipment that consumes electrical energy.

Local Safety Instructions: A set of instructions regarding the Safety Precautions on MV/ HV Equipment to ensure the safety of personnel carrying out work or testing on the Distribution System.

Low Voltage (LV): A voltage level not exceeding 0 – 250Volts

Maintenance Program: A set of schedules, which are coordinated by the Distributor and the System Operator, specifying planned maintenance for equipment in the Distribution System or in any User System.

Manual Load Dropping (MLD): The process of manually and deliberately removing pre-selected Loads from a power system, in response to an abnormal condition, and in order to maintain the integrity of the System.

Medium Voltage (MV). A voltage level between 250V and 650V.

Ministry of Energy: The Government Ministry, which was provided with the additional mandate under the Electricity Act Chapter 13:19 of supervising the restructuring of the electricity industry, developing policies and procedures, formulating and implementing programs, and promoting a system of incentives that will encourage private sector investments and reforms in electricity industry and ensuring an adequate and reliable supply of electricity.

Momentary Average Interruption Frequency Index (MAIFI): The total number of momentary customer power interruption within a given period divided by the total number of customers served within the same period.

Momentary Interruption: An interruption whose duration is limited to the period required to restore service by automatic or supervisory controlled switching operating or by manual switching at a location where an operator is immediately available.

Negative Sequence: One of the three sequence companies that represent an unbalanced set of voltages or currents.

Non-Technical Loss: The component of system loss that is not related to the physical characteristics and functions of the electrical system, and is caused primarily by human error, whether international or not. Non-technical loss includes the Energy lost due to pilferage, tampering of meters and erroneous meter reading.

Normal state: The grid operating condition when the system frequency, voltage and transmission line and equipment loading are within their normal operating limits, the operating margin is sufficient and the grid configuration is such that any fault current can be interrupted and the faulted equipment isolated from the grid.

Overvoltage: A Long Duration Voltage variation where the RMS value of the voltage is greater than or equal to 110 percent of the nominal voltage.

Point of grounding. The point on the distribution system or the user system at which isolation can be established for safety purposes.

Point of isolation: The point on the distribution system or the user system at which isolation can be established for safety purposes.

Power Factor: The ratio of Active Power to Apparent Power.

Power Quality: The quality of the voltage, including its frequency and resulting current that is measured in the Grid, Distribution System, or any User System.

Reactive Energy: The integral of the Reactive Power with respect to time, measured in VARh, or multiples thereof.

Reactive Power: The component of electrical power representing the alternating exchange of stored energy (inductive or capacitive) between two Systems, measured in VAR, or multiples thereof. For AC circuits or Systems, it is the product of the RMS voltage and the RMS value of the quadrature component of alternating current. In a three-phase system, it is the sum of the Reactive Power of the individual phases.

Reactive Power Capability Curve: A diagram which shows the Reactive Power capability limit versus the Real Power within which a Generating Unit is expected to operate under normal conditions.

Registered Data: Data submitted by a User to the Distributor Grid (or owner) at the time of connection of the User System to the Distribution System (or Grid).

Reliability: The probability that a System or Component will perform a required task or mission for a specified time in a specified environment. It is the ability of a power system to continuously provide service to its Customers.

Safety Coordinator: A person designated/authorised by the Distributor (or User) to be responsible for the coordination of Safety Precautions at the Connection Point when work or testing is to be carried out on a System which requires the provision of Safety Precautions for MV or HV Equipment.

Safety Precautions: Refers to the Isolation and Grounding of MV or HV Equipment when work or testing is to be done on the Distribution System

Safety Rules: The rules that seek to safeguard personnel working on the equipment of the Generation, Transmission and Distribution Systems.

Scheduled Maintenance: The outage of a component or Equipment due to maintenance, which is coordinated by the Distributor or user, as the case may be.

Shut down: The condition of an Equipment when is de-energised or disconnected from the system.

Significant Incident: It is an event on the distribution system of any user that has a serious or widespread effect.

Site. Refers to a substation or switchyard in the grid, distribution system of the user system where the connection point is situated.

Spinning Reserve: The component of contingency Reserve, which is synchronised to the grid and ready to take load. Also called hot standby reserve

Stability: The ability to the dynamic components of the power system to return to a normal or stable operating point after being subjected to some form of change or disturbance.

Standard Planning Data: The general data required by the Distributor as part of the application for a connection agreement or Amended connection agreement.

Supplier: Refers to any person or entity authorised by ZERA to sell, broker, market or aggregate electricity to the end users.

Supply of Electricity: The sale of electricity by party other than a generator or a Distributor or a Distributor in the franchise area of a distribution utility using the wires of the Distribution.

Switched Neutral Pole: The second, fourth or neutral pole that is switched simultaneously with the main phase pole.

Synchronised: The state when connected generating units or interconnected AC systems operate at the same frequency and where the phase angle displacements between their voltages vary about a stable operating point.

System: Refers to the distribution system or any user system. Also, a group of components connected or associated in a fixed configuration to perform a specified solution.

System Average Interruption Duration Index (SAIDI): The total duration of sustained customer power interruption within a given period divided by the total number of customers served within the same period.

System Average Interruption Frequency Index (SAIFI). The total number of sustained customer power interruptions within a given period divided by number of customers served within the same period.

System Loss: In a distribution system, it is the difference between the electric energy purchased and or generated and the electric Energy sold by the Distributor.

System Operator: The party responsible for Generation Dispatch, the provision of Ancillary Services, and operation and control to ensure safety, power Quality, stability, reliability and the security of the Grid.

System Test: The set of tests which involves simulating conditions or the controlled application of unusual or extreme conditions that may have an impact on the Distribution System or the user system.

Technical Loss: The component of System Loss that is inherent in the physical delivery of electric Energy. It includes conductor loss, transformer core loss, and technical error in meters.

Test and Commissioning: Putting into service a System or Equipment that has passed all required tests to show that the System or Equipment was erected and connected in the proper manner and can be expected to work satisfactorily.

Top-up: The Supply of Electricity by the Distributors to the Customer on a continuing or regular basis to compensate for any shortfall between the Customer's total supply requirements and those met from other sources.

Total Harmonic Distortion (THD): The ratio of the root-mean-square value of the harmonic content to the root-mean-square value of the fundamental quantity, expressed in percent.

Transfer switch: An automatic or non-automatic device for transferring one or more load conductor connections from one power source to another.

Safety:

Transformer: An electrical device or equipment that converts voltage current from one level to another.

Transient Voltages: High-frequency Overvoltages caused by lightning, switching of capacitor banks or cables, current chopping, arcing ground faults, ferroresonance and other related phenomena.

Underfrequency Relay (UFR): An electrical relay that operates when the System Frequency decreases to a preset value.

Undervoltage: A Long Duration Voltage Variation where the RMS value of the voltage is less than or equal to 90 percent of the nominal voltage.

Voltage Control: The strategy used by the System Operator, Distributor, or User to maintain the voltage of the Grid, Distribution System, or the User System within the limits prescribed by the Grid Code or the Distribution Code.

Voltage Dip: Has the same meaning as Voltage Sag.

Voltage Sag: A Short Duration Voltage Variation where the RMS value of the voltage decreases to between 10 percent and 90 percent of the nominal value.

Voltage Unbalance: The maximum deviation from the average of the three phase voltages divided by the average of the three phase voltages, expressed in percent.

Voltage Variation: The deviation of the root-mean-square (RMS) value of the voltage from its nominal value, expressed in percent.

Zimbabwe Electricity Regulatory Commission: The independent quasi-judicial regulatory body created pursuant to Electricity Act [*Chapter 13:19*] which is mandated to promote competition, encourage market development, ensure customer choice and penalize abuse of market power in restructured electricity industry and among other functions, promulgate and enforce the Zimbabwe grid code and the Electricity Distribution code.

APPENDIX II

REVISIONS TO THIS CODE

No.	Date	Version	Description
00	May 2006	ZERC	Inception of code
01	15/08/2013	1	Document font changed from Comic Sans 12 to Arial 11
02	23/09/2013	1	Table of Contents created
03			The introduction was rephrased to in incorporate current trends
04			Commission was replaced with Authority
05			watt was changed to Watt
	Abbreviations		IRR was renamed IRReg for Implementing Rules and Regulations
06			ZERC was replaced with ZERA throughout the document.
07			IRR was abbreviated for Internal Rate of Return
1.1			Amended "management" to "governance" of the code
1.1			Amended the introduction of the governance of the code
1.3			Amended the responsibilities of the DCRP
1.4			Amended, ZERA now appoint chair of the DCRP
1.5			Inserted TORs for the distribution review panel
1.6			Inserted Section 1.6 to deal with "derogation"
1.10.1			Inserted the four weeks deadline
1.10.4			Inserted Version control
Section 2.1.9	August 2013	Page 9	Inclusion of the BIL for different voltages
Section 2.2.7	August 2013	Page 12	Inclusion of generator connection application fees
Section 2.2.7	August 2013	Page 12	Inclusion of Customer Demand Application Fees
Section 2.4.11	August 2013	Page 16	Inclusion of distribution system fault levels
Section 5.13	August 2013	Page 56	Inclusion of installation of standby generators within the distribution network
Section 9.11.2	August 2013	Page 75	Inclusion of Key Performance Indicators, QoSS parameters"