POWER PLANNING ASSOCIATES LTD
ENERGY & MANAGEMENT CONSULTANTS

COMMON GUIDELINES ON MINIMUM QUALITY OF SERVICE AND RELIABILITY STANDARDS FOR ELECTRICITY

Final Draft Guidelines with Technical Annex

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GLOSSARY OF TERMS

Common mode failure (3.2.1)

> COMMON MODE FAILURE is where a single incident, the cause of which is external to the system in question, places a number of system components at risk at the same time. For example, where a substation can be segregated into two sections, the sections should be in separate buildings with fireproof walls so that, in case of a fire in one location, the second section can still be used.

Compatibility Levels (3.4.6)

> COMPATIBILITY LEVELS are defined as those disturbance level which must not be exceeded for 95% of measurements taken in the entire network (IEC 61000-2-12).

Contactors (3.4.10)

> A Contactor is an electrical relay used to control the flow of power in a circuit and which requires a defined minimum voltage level to be present in order to keep electrical contact.

Control areas (3.4.4)

> In a CONTROL AREA there is a common generation control scheme, and the area is operated by a single TRANSMISSION SYSTEM OPERATOR (TSO). Interconnections within a CONTROL AREA ("tie-lines") are strong compared with interconnections with neighbouring TSOs, and typically these tie-lines are metered for export and import.

Customer

> A person or legal entity who buys electricity under a supply agreement with a licensee or vertically integrated electricity utility.

Delivery Point (3.4.6)

> The DELIVERY POINT is the point of physical connection between one licensee's network and another licensee's network or a CUSTOMER'S facilities (e.g. the connection between TRANSMISSION SYSTEM and a DISTRIBUTION SYSTEM, or between the DISTRIBUTION (or TRANSMISSION) SYSTEM and a CUSTOMER'S facilities. This is also typically the point of metering.

Demand (3.1.1)

> DEMAND is the rate at which electric power is delivered to consumers connected to the network. DEMAND can be considered in a given instant, expressed typically in MW, or a DEMAND over a time period can be expressed, for example annual consumption in MWh.

Distributed Generation (DG) (3.3.1)

DISTRIBUTED GENERATION (DG) is electricity production that is close to the load centre, and connected to the distribution level. DG may be beyond the control of the system operator, and is typically small-scale generation. Some definitions of DG are given by size, for example a CIGRE working group defines DG as all generation units with a maximum capacity of 50 to 100 MW[1].

Distribution System (3.3.1)

The DISTRIBUTION SYSTEM is the network that comprises the equipment between the TRANSMISSION SYSTEM and the CUSTOMER'S service switch.

Distribution System Operator (DSO) (3.3.1)

The DISTRIBUTION SYSTEM OPERATOR (DSO) is the organisation that operates the DISTRIBUTION SYSTEM (see Distribution System).

Event (planned or unplanned) (3.4.2)

A network occurrence typically resulting in the switching of circuit breakers and other equipment which may result in a loss of supply to one or more CUSTOMERS.

Extra High Voltage

A network operating voltage in the range $V \geq 400kV$.

Feeder (3.5.8)

A circuit in the DISTRIBUTION SYSTEM used to distribute power from a substation to smaller substations or customer connections.

Frequency Excursion Event (3.4.4)

An occurrence in which the frequency moves outside the permitted range.

Fuse (3.5.9)

In the context of these Guidelines, the FUSE refers to the main incoming fuse located at the CUSTOMER's premises but which is in the ownership and control of the DISTRIBUTION SYSTEM OPERATOR.

[1] Pepermans, Driesen, Haeseldonckx, D'haeseleer and Belmans; *Distributed Generation: Definition, Benefits, and Issues*; August 2003;

Geographic Information Systems (3.5.5)

A GEOGRAPHIC INFORMATION SYSTEM is a collection of computer hardware, software and geographic data that enables the user to capture, store and analyse geographically referenced information.

High Voltage

A network operating voltage in the range 33kV < V < 400kV.

Interconnected Systems (3.4.4)

An Interconnected System is one where two or more individual TRANSMISSION SYSTEMS are physically connected and normally operate in synchronism.

Interruption (3.4.3.1)

An INTERRUPTION is an occurrence in which the continuity of supply of electricity to a customer is broken.

Island System (3.4.4)

An ISLAND SYSTEM is a network that normally operates without a connection to the main grid (Definition as per PIESA Specification 1048).

Long Interruption (3.4.3.1)

A LONG INTERRUPTION is an interruption that lasts longer than 5 minutes.

Long Term Flicker Severity (P_{lt}) (3.4.8)

FLICKER may be defined as the sensation experienced by the human eye when illumination levels change. It is quantified on the basis of the level of visual disturbance experienced and is calibrated such that a P_{lt} of 1.0 corresponds to flicker at the level of perception for 50% of the population when reading with a 60W incandescent lamp. Flicker severity evaluated over a long period (hours) using successive Short Term Flicker Severity (P_{st}) values. For example, PIESA Specification 1048 defines P_{lt} as calculated over a 2 hour period.

Low Voltage (LV) (3.4.6)

A network operating voltage of up to 1 kV ac or 1.5 kV dc.

Medium Voltage (MV) (3.4.6)

A network operating voltage in the range 1kV < V ≤ 33kV.

Momentary Interruption (3.4.3.1)

A MOMENTARY INTERRUPTION is an interruption that lasts less than 5 minutes for voltage levels less than 33 kV (as per IEEE and PIESA definitions). Where countries use different definitions (e.g. interruptions of less than 3 minutes), this should be clearly stated.

Outage (3.4.1) (Planned and unplanned)

The removal from service of part of the power system, whether due to planned or unplanned circumstances, either through automatic or manual disconnection.

PABX (Private Automatic Branch eXchange) (3.5.12)

A PABX System makes connections among the internal telephones of a private organisation, and to a public switched telephone network. Functionality of the PABX system may include providing information for accounting purposes.

Planned Maintenance Outages (3.4.2.2)

PLANNED MAINTENANCE OUTAGES are defined as those which are scheduled for routine maintenance, to allow for the construction of new system assets or enable the connection of new users.

Planning Levels (3.4.6)

PLANNING LEVELS are chosen such that compatibility levels are met. They are the power quality objectives of utilities, and although they can be less than or equal to compatibility levels, they are typically less than.

Reserve (3.1.1)

RESERVE is the amount of generating capacity that can be used to produce active power over a given period of time, which has not already been committed to the production of energy over this period. It may be defined in different categories according to the timescale within which it can be made available.

SCADA (3.4.3.3)

A SCADA (Supervisory Control and Data Acquisition) system comprises the hardware, software and communications mechanisms used by TRANSMISSION SYSTEM OPERATORS and DISTRIBUTION SYSTEM OPERATORS to monitor and operate their networks.

Supply Company (3.4.7)

A SUPPLY COMPANY is an organisation that is authorised by licence or other legal provision to sell electricity to CUSTOMERS.

Transmission Network (3.2.1)

A TRANSMISSION NETWORK the set of HIGH VOLTAGE or EXTRA HIGH VOLTAGE assets owned and/or operated by a TRANSMISSION SYSTEM OPERATOR.

Transmission System Operator (TSO) (3.2.1)

The TRANSMISSION SYSTEM OPERATOR is the organisation that owns and/or operates the transmission system assets.

Unplanned Outages (3.4.2.3)

UNPLANNED OUTAGES are defined as forced outages taken by the system operator without sufficient notice or outages due to tripping of circuits due to a fault or other unplanned occurrence. The minimum period of notice for a planned outage should be set by the regulator.

Vending Station (3.5.5)

A VENDING STATION is a place where customers can purchase credit in order to top-up prepaid electricity meters.

Voltage Dip (Sag) (3.4.10)

VOLTAGE DIPS are brief periods (in the order of milliseconds and seconds) in which the voltage drops below the nominal level.

Voltage Excursion Event (3.4.5)

A VOLTAGE EXCURSION EVENT is where the voltage at any busbar on the TRANSMISSION SYSTEM or DISTRIBUTION SYSTEM moves outside the permitted range.

Voltage Unbalance (3.4.9)

VOLTAGE UNBALANCE occurs where there exists a difference in voltage magnitude between phases and/or a shift in the phase separation from 120° (for a three-phase system).

1 Introduction

This report describes the development of a set of Common Guidelines on Minimum Quality of Service and Reliability Standards for Electricity, which has been carried out by Power Planning Associates Ltd (PPA) for the African Forum for Utility Regulators (AFUR). The Draft Guidelines have been modified in the light of discussions that took place at the AFUR Workshop which was held on 3rd and 4th December 2007.

In order to define the minimum standards which are appropriate for application to the electricity industries in the AFUR member countries, reference is made to the range of standards that is in place already within these countries. An international benchmarking assessment is also provided, indicating the types and levels of standards that are in use in other electricity sectors regionally and worldwide. Building on these bases, a set of Common Guidelines is proposed for adoption as the minimum standard to be applied across all of the AFUR member countries.

In developing guidelines for supply quality and reliability, it is important to distinguish two types of standards:

- **Planning standards** for generation, transmission and distribution systems, which set the target levels of supply quality and reliability to be achieved in designing the power system; and

- **Operating and Performance standards**, which define the targets to be achieved in operating the systems and providing supplies to end customers, and the measures which are to be utilised in monitoring the success of utilities in complying with the standards.

From the regulatory perspective, planning standards are significant in that they form the framework within which future expenditure on network expansion/refurbishment and the system operations functions are calculated and justified. Operating and Performance standards are more directly concerned with customer protection, in that they measure the effectiveness of the utilities in delivering to end consumers the target levels of performance.

The standards that are analysed in this report and the guidelines which have been prepared are presented under the above headings. Where applicable, they are further subdivided into generation, transmission, distribution and supply standards. They are defined in terms of minimum targets and measurement practices which it is proposed should be achievable by the utilities in the AFUR member countries. Whilst these are minimum proposed standards they reflect an underlying objective of continuous improvement towards achieving internationally accepted standards in the future; they should therefore be subject to review by AFUR as the performance of the utilities in the member countries improves over time.

A Technical Annex to the main Guidelines presents more detailed information regarding the calculations that are required to support the application of the Guidelines themselves.

2 International, Regional and AFUR Country Standards

2.1 Background

International standards have been examined relating to electricity supply quality and reliability in a number of electricity sectors, including the United Kingdom, Europe and the United States. Draft standards that have been prepared in Sri Lanka have also been reviewed. In addition, the status of the ongoing work on harmonisation of standards that is being undertaken by the Regional Electricity Regulators Association (RERA) in the SADC countries has been considered, as has the co-ordinating role of the Southern African Power Pool (SAPP) in relation to transmission system planning and operation for its twelve member countries. The results of this review indicate a wide range of different approaches to developing standards for electricity supply quality and reliability, although a number of common themes emerge in terms of the range of parameters that are considered and the way that the standards are applied.

2.2 International standardisation

In many jurisdictions, reference is made to key standards that have been adopted by international standards organisations. Where appropriate, we have referred to these in the guidelines developed below. The major international references that are applicable include:

- IEC 61000: Electromagnetic compatibility (EMC)
- European Standard 50160: Voltage characteristics of electricity supplied by public distribution systems
- IEEE Standard 1366-2003: IEEE Guide for Electric Power Distribution Reliability Indices

In addition to these public standards, national regulators have produced a wide range of standards covering electricity supply quality and reliability, and various international regulatory bodies have worked on the harmonisation of these and the analysis of regional trends in order to promote best practice. Notable examples include the work carried out by the Council of European Energy Regulators in identifying the most commonly applied indices for supply reliability and measures of supply quality across Europe[2].

2.3 Regional standardisation

A number of regional initiatives are being pursued in Africa to produce harmonised standards for different aspects of power system performance which can be applied by national regulatory bodies. It is important to note that in all cases these initiatives represent a voluntary pooling of information and experience for the benefit of all the participants – there

[2] Council of European Energy Regulators, "Third Benchmarking Report on Quality of Electricity Supply 2005"

is no “pan-African” regulatory body with the power to enforce common standards in multiple countries.

The specific work which has been noted in the preparation of these guidelines includes:

- the initiative being pursued by RERA to harmonise technical standards in the SADC region in the key areas of Grid Codes, Quality of Supply and Service Standards, Energy Efficiency Practices, Safety Codes and Off-Grid Codes & Practices. This has included carrying out country reviews to confirm the degree of coverage of these areas by different SADC member countries, the regulatory reporting requirements imposed on Licensees under different types of licences, the arrangements that are in place for the collection, collation, storage and management of technical information from licensees and the different compliance monitoring and enforcement mechanisms that are required;

- the work of SAPP in coordinating planning and supply security standards at the transmission level throughout the SADC region. These are particularly relevant for the 9 Operating Members of SAPP (Namibia, South Africa, Lesotho, Swaziland, Mozambique, Botswana, Zimbabwe, Zambia, Democratic Republic of Congo); and

- the preparation by the Power Institute for Eastern and Southern Africa (PIESA) of a draft PIESA 1048 Specification on Quality of Supply[3]. The PIESA 1048 Standard (specification) covers voltage quality parameters with the associated compatibility levels, limits, and assessment methods focusing on voltage quality at the point of supply to end customers of electricity utilities. Consideration is being given to the adoption of PIESA 1048 as the basis for supply quality standards in the region. Its provisions are closely related to the South African standard NRS 048, and there is therefore a solid base of experience that has already been gained in South Africa regarding the applicability of the standards that it proposes.

2.4 Standards adopted in the AFUR countries

A questionnaire was issued to the regulators that are members of AFUR at the start of this project requesting details of the planning, operation and customer performance standards that are in place in each country. Responses to the questionnaire that have been received from Algeria, Ghana, Malawi, Namibia, South Africa, Tanzania, Togo and Zambia have been considered in preparing these guidelines, together with public domain information from Kenya, Nigeria, Uganda and Zimbabwe. Responses from Côte d’Ivoire and Niger which were received after the deadline for submissions will be taken into account in the later stages of this work. Table 1 summarises the areas of coverage of the current standards on a country basis.

[3] PIESA is a regional power utility association established in 1998 to co-ordinate information and technology sharing in relation to technology and engineering support, applied research, standardisation, technical development and training, and environmental management.

Table 1. Summary table of AFUR country coverage of standards

	South Africa	Zambia	Togo	Malawi	Zimbabwe	Uganda	Tanzania	Nigeria	Ghana	Kenya	Algeria	Namibia	Ethiopia
Documentation reviewed	NRS 048, Grid Code, Distribution Code	ZS 387: 2000	Reglement du Service Concede	Quality of Service and Supply Standards 14/10/05	Grid Code	Electricity Primary Grid Code regulations 2003	Tanesco Grid System operations guideline	Nigeria Grid Code and Distributi on Code	Electricity supply and distribution (standards of performance) regulations, 2007	Grid code 3	Response to Questionnaire	Grid code - network	Electricity services quality standard directive
Transmission and Distribution Reliability Indices	✓	✓		✓			✓	✓	✓				
Voltage Regulation	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
Frequency	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	✓	
Voltage Unbalance	✓	✓	✓	✓	✓	✓		✓				✓	
Harmonics	✓	✓	✓	✓	✓	✓		✓				✓	✓
Voltage Flicker	✓	✓		✓								✓	
Voltage Dips	✓	✓		✓								✓	
Voltage Swells	✓											✓	
Signalling Voltage	✓						✓	✓					
New Connections	✓	✓	✓	✓	✓				✓			✓	✓
Frequency of meter readings	✓	✓	✓		✓			✓		✓	✓	✓	✓
Frequency of bills						✓							✓
Disconnection due to non payment	✓	✓	✓	✓		✓				✓		✓	✓
Prepayment meters	✓	✓			✓				✓				
Account queries	✓	✓	✓			✓						✓	✓
Meter Accuracy queries	✓	✓	✓	✓	✓	✓		✓	✓	✓		✓	✓
Notice for planned interruptions	✓	✓	✓	✓					✓		✓	✓	✓
Response to general complaints	✓	✓	✓	✓		✓		✓		✓		✓	✓
Telephone services	✓	✓		✓	✓								

The level of detail and range of coverage of the standards in different countries varies widely, reflecting factors such as the differing levels of development of the electricity sector reform processes in each country, the condition of the electricity networks and the level of consumers' expectations in the area of customer service generally. In many cases, where there are standards for supply reliability and quality in place in a given country, these are either explicitly based on the international or regional standards referred to above, or are largely compatible with these.

Most of the AFUR member countries, in common with standard international practice, have standards in place covering the core technical criteria of voltage regulation, frequency control, voltage imbalance and harmonics. These are fundamental supply quality issues, although voltage imbalance and harmonics problems are typically associated with utilities that have higher load densities on their networks, particularly arising from commercial and industrial loads, which have the potential for the greatest level of harmonic penetration. Provisions governing voltage flicker and voltage dips are covered by standards in South Africa and Zambia; again, these tend to be associated more with the effects of industrial demands, where motor starting, mining and smelting operations, etc., cause sudden step changes in the level of current that is required at particular points on the transmission and distribution network. Internationally, the application of standards for voltage flicker is common practice, as this can be a major cause of customer complaints.

In terms of supply reliability, some of the AFUR member countries have reporting requirements or standards specified for key reliability indices, however the details of these vary. Given the moves internationally towards standardising measures of supply reliability, it is proposed that a common set of measures of the frequency and duration of supply failures should be introduced, and details of these are given in the proposed Guidelines.

In relation to the management of key aspects of the customer relationship that affect the continuity of electricity supplies, the accuracy of metering, etc., there are widely varying standards in place across the AFUR member states, as indicated by Table 1. A similar situation applies across other international regions, and a minimum set of customer protection criteria has therefore been proposed which can be built upon in the future by the AFUR members.

The experience of the different countries as reported in the questionnaire submissions and other public domain information has been extensively drawn upon in developing the Guidelines contained in this report, whilst ensuring that a regional and international perspective is also brought into to the work.

2.5 Underlying principles adopted in developing Guidelines

International experience, together with evidence from data submissions received from the AFUR members themselves, indicates that two categories of supply quality and reliability standards are typically applied:

- **Planning Standards**, which set the basic criteria against which utilities plan their networks and systems; and

- **Operating and Performance Standards**, which define the targets against which the success or otherwise of utilities in delivering supplies and services to end consumers can be measured. These may be split into two subgroups of standards, namely:

  – overall standards, which define the range of measures and reports that are to be received and monitored by regulators on a regular basis; and

  – guaranteed standards, often accompanied by financial penalties, which define the minimum level of service to which each individual consumer is entitled.

2.5.1 Planning Standards

Power systems should be designed to ensure that the consumer demand can be met and that the system operates in a satisfactory manner under both steady state and dynamic conditions. The setting of tailored reliability standards for a particular country and network can involve the consideration of a wide range of technical and economic factors which are country-specific, and it will always be necessary for national regulators and utilities to work closely together to determine the specific standards that should apply in any particular situation. It is nevertheless possible to identify a number of core parameters which need to be assessed in system planning and operation, and an indicative set of targets for these has been prepared which is appropriate for application across the of AFUR member countries.

2.5.2 Operating and Performance Standards

In setting guidelines relating to operating and performance standards for the AFUR member countries, a number of points need to be borne in mind:

- standards should be based on the principle of seeking continuous improvement in performance, from a baseline that is set from an analysis of present utility performance;

- the ability to monitor existing performance is dependent on the accuracy of reporting system performance which in turn relies on the existence of adequate system information, either from automated control and monitoring systems or from manual record keeping;

- the performance targets may vary between different areas in accordance with levels of performance currently achievable, the topography, customer profiles, load density and other technical and commercial criteria.

The effect of these various factors is to make it difficult to set specific numerical targets for standards which are appropriate in each of the AFUR countries individually. The role of the guidelines presented in this document is to suggest numerical standards where possible, but also to propose the common principles which underpin the standards that should apply in each country, to ensure that as far as possible the same principles of customer protection are being adopted. The regulators in individual countries may agree different specific targets as applicable to their utilities' networks and circumstances, whilst keeping in view the broad objectives of the guidelines that have been proposed.

3 Proposed minimum quality of service and reliability standards for electricity

3.1 Generation Planning

3.1.1 <u>Criterion: Generation planning standards</u>

Minimum Standard: A long term generation expansion plan should be produced demonstrating that generation projects are proposed which will meet the requirements for forecast demand, exports and reserves.

Determination of compliance: The long term generation plan should be reviewed annually by the regulator.

3.2 Transmission System Planning

3.2.1 <u>Criterion: Transmission system security standard</u>

Minimum Standard: All transmission networks should be designed to achieve at least a deterministic "n – 1" security standard, i.e. supplies to all loads should be uninterrupted for the loss of a single network component at these voltage levels. Derogations from this standard are permissible subject to regulatory approval.

General rules for an acceptable level of security for the connection of power stations or generators should be established by the transmission system operator (e.g. n-1 security where the power station is greater than a given size).[4]

The possibility of common mode failure should be eliminated at the design stage wherever possible.

Transmission assets are defined as all those assets owned and/or operated by the national system operator.

Determination of compliance: Transmission planning studies using computer load flow models should be undertaken to investigate the effects of disconnecting single generating units, transmission circuits, transformers, busbars, shunt capacitors/reactors and other devices on the ability to supply system maximum demand without infringing planning standards for voltages or equipment ratings.

Planning studies using computer models of the transmission system suitable for undertaking load flow and transient stability studies (i.e. with models of the generator control systems) should be undertaken to investigate the effect of the connection of power stations in respect of system outages and on transient stability.

[4] Note: this does not imply that the cost of the connection should be covered by the transmission system operator – each country and transmission system operator is likely to have its own rules in place regarding the sharing of connection and reinforcement costs associated with new generation projects.

3.3 Distribution System Planning

3.3.1 <u>Criterion: Distribution system security standard</u>

Minimum Standard: General rules for an acceptable level of security for the different parts of the distribution system should be established by the distribution system operator taking account of fault rate, restoration times and the requirement of the distribution system performance standards. For example the system could be split according to the size of MW demand fed from a particular area of the network, or the number of customers connected, and differential security criteria applied to the different demand categories. Regulators may also wish to apply different security standards according to customers in urban and rural locations.

Table 2. Distribution system security levels by category

Group demand	Customer Location	MW Size	Number of Customers	Demand to be met without infringement of voltage standards or equipment ratings following a single equipment[1] outage
Category 1	Urban	> X	> x	All to be met continuously (i.e. network design to n - 1 security criteria)
	Rural	> Y	> y	
Category 2	etc.	etc.	etc.	All within 60 seconds (Automatic system reconfiguration)
Category 3				All within 15 minutes (Remote manual switching)
Category 4				All within 3 hours (Manual reconfiguration)
Category 5				All within repair or replacement time of equipment. (Where these times are significant they may be incompatible with the SAIDI requirements specified in Section 3.4.3.2 and the system operator spares policy and standby generator policy should be taken account of at the planning stages)

Note 1: Distribution circuits, transformers, compensation equipment and busbars should be considered.

This table could consider a second circuit outage (fault following and arranged circuit outage). Consideration could also be given to the impact of distributed generation on overall system reliability.

Determination of compliance: Distribution planning studies using computer load flow models should be undertaken to investigate the effects of disconnecting single distribution circuits, transformers, busbars, shunt capacitors/reactors and other devices on the ability to supply system maximum demand without infringing planning standards for voltages or equipment ratings.

3.4 System Performance and Operational Standards

3.4.1 <u>**Criterion: Maintenance planning**</u>

Minimum Standard: Maintenance should be planned by both the transmission system operator and the distribution system operator to minimise the risk of outages. For interconnected transmission systems maintenance should be planned jointly with the neighbouring transmission system operators to minimise the risk of outages.

Determination of compliance: The planned and actual maintenance schedules should be available for audit on an annual basis. Network companies may need to account for the difference between the planned and actual schedules.

3.4.2 <u>**Criterion: Transmission system performance**</u>

Minimum Standard: Transmission system performance should be assessed by the transmission system operator who should record the date, start time, and duration of each individual planned or unplanned event, the number of transmission circuits and the number of customers affected in order to determine the following indices:

3.4.2.1 System availability index

An index should be calculated for each month and reported annually giving the overall percentage availability of the transmission network. This should be calculated as the sum for all the transmission circuits of the number of hours in the month for which each circuit is available, divided by the product of the total number of circuits in the system and the number of hours in the month.

The regulator should set a figure for the minimum required monthly system availability index, which should normally exceed 90% and, in developed networks, is often measured in excess of 95% availability. This figure should be subject to continuous improvement by the regulator and transmission system operator.

3.4.2.2 System planned unavailability index

The system planned unavailability index should be calculated for each month and reported annually giving the overall percentage planned unavailability of the transmission network.

The system planned unavailability index is calculated as the sum for all the transmission circuits of the number of hours in the month for which each circuit experiences a planned outage, divided by the product of the total number of circuits in the system and the number of hours in the month.

Planned maintenance outages are defined as those which are scheduled for routine maintenance, to allow for the construction of new system assets or enable the connection of new users.

The regulator should set a figure for the maximum required monthly system planned unavailability index by considering failure rates and repair times. It would be expected that this figure would vary on a monthly basis according the total system demand as planned maintenance would be scheduled for periods of low total system demand. Typically this figure will vary between 2% and 8%. This figure should be subject to continuous review by the regulator and transmission system operator to ensure the best possible maintenance regime is undertaken.

3.4.2.3 System unplanned unavailability index

This index should be calculated for each month and reported annually giving the overall percentage unplanned unavailability of the transmission network.

The system unplanned unavailability index is calculated as the sum for all the transmission circuits of the number of hours in the month for which each circuit experiences an unplanned outage, divided by the product of the total number of circuits in the system and the number of hours in the month.

Unplanned outages are defined as forced outages taken by the system operator without sufficient notice or outages due to tripping of circuits due to a fault or other unplanned occurrence. The minimum period of notice for a planned outage should be set by the regulator, for example 24 hours.

The regulator should set a figure for the maximum required monthly system planned unavailability index by considering failure rates, repair times and maintenance practice. This figure typically varies between 0.1% and 1% in developed networks. This figure should be subject to continuous improvement by the regulator and transmission system operator.

3.4.2.4 Number of loss of supply incidents

The number of incidents that take place on the transmission system which result in a loss of supply to end consumers, both those connected at the transmission level and those connected to the distribution network, should be recorded on a monthly basis and reported on annually.

3.4.2.5 Estimated unsupplied energy

The total estimated unsupplied energy arising from loss of supply incidents should be determined monthly and reported on annually.

3.4.2.6 Average duration of loss of supply incidents

The average duration of loss of supply incidents should be calculated as a demand weighted average of the total interruptions experienced on the system on a monthly basis and reported on annually. The average duration of loss of supply incidents is calculated as the estimated annual total energy unsupplied divided by the total MW demand lost.

The transmission system operator should endeavour to reduce the average duration of loss of supply incidents, the total unsupplied energy and the loss of supply incidents to zero if the transmission system is designed to a (n-1) security criterion. Where the transmission system is not designed to a (n-1) security criterion the regulator should set a figure for these incidents taking account of the system design, failure rates and repair times. This figure should be subject to continuous improvement by the regulator and transmission system operator and should be reviewed following significant changes to the transmission system.

3.4.2.7 Application of SAIDI/SAIFI indices (see also Section 3.4.3)

Consideration should be given to the application of indices such as the System Average Interruption Duration Index (SAIDI) or the System Average Interruption Frequency Index (SAIDI) to the transmission networks as a future development, but focusing on the application of these at connection points on the transmission network rather than specific customer installations, in order to provide an additional measure of transmission network performance.

Determination of compliance: The required indices should be reported on an annual basis and compared over a sliding window for the previous five years. Indices which fall outside the agreed limits should be highlighted.

3.4.3 <u>Criterion: Distribution system performance</u>

Minimum Standard: A long term aim of the Distribution System Operator should be to assess the Distribution system performance by recording the date, start time, and duration of each individual planned or unplanned event and the number of customers affected in order to determine the following indices: SAIFI, SAIDI and CAIDI. Where this is currently impracticable, the Distribution System Operator should record sufficient information to determine the Average Energy Not Supplied per customer. It should be noted that these indices are initially applicable only to interconnected systems, and not isolated ones.

3.4.3.1 SAIFI (system average interruption frequency index)

SAIFI is the average number of supply interruptions per customer per year.

SAIFI is defined as the total number of customer interruptions due to the distribution system in a month divided by the total number of connected customers.

The index excludes momentary interruptions, such as interruptions restored by automatic action (e.g. autoreclose). Many of these incidents are not captured in reporting incidents and their inclusion would validate wider comparisons.

The data for interruptions due to planned, unplanned and load shedding requirements should be evaluated separately. SAIFI is the sum of the three factors. SAIFI should be calculated on a monthly basis and reported annually.

3.4.3.2 SAIDI (system average interruption duration index)

SAIDI is the average duration of supply interruptions per customer per year.

SAIDI is defined as the sum of the customer interruption durations (minutes) due to the distribution system each month divided by the total number of connected customers.

The data for interruptions due to planned, unplanned and load shedding requirements should be evaluated separately. SAIDI is the sum of the three factors. SAIDI should be calculated on a monthly basis and reported annually.

3.4.3.3 CAIDI (customer average interruption duration index)

CAIDI is the average duration of each supply interruption per customer who experienced the interruption per year.

CAIDI is defined as the sum of all the customer interruption durations divided by the total number of customer interruptions. (CAIDI = SAIDI/SAIFI)

The data for interruptions due to planned, unplanned and load shedding requirements should be evaluated separately. CAIDI is the sum of the three factors. CAIDI should be calculated on a monthly basis and reported annually.

The regulator should set a maximum figure for the indices; some international published figures are detailed below:

Table 3. Distribution system performance indices

	Great Britain	**France**	**Spain**	**Ireland**	**North American Utilities**
SAIFI per year	2001 to 2006 varies between 0.75 and 0.8.	2001 to 2004 varies between 1.1 and 1.3	2001 to 2004, 2.3	1999 to 2004 varies between 1.1 and 1.7	Median value 1.1
SAIDI minutes per year	2001 to 2006 varies between 65 and 110	1999 to 2004 varies between 45 and 50	1999 to 2004 varies between 150 and 190	1999 to 2004 varies between 350 and 550	Median value 90
CAIDI minutes per year/event					Median value 81.6

It may be desirable to specify different indices depending on the design and type (residential, commercial, industrial, urban and rural, overhead or underground) of network. In addition, consideration could be given to monitoring short (momentary < 5 minutes) interruptions (MAIFI) and long interruptions (SAIFI) separately. The definition of a momentary interruption being less than 5 minutes is as per IEEE and PIESA standards for voltage levels ≤33kV. Where countries use a different definition, this should be clearly stated when data is being compared among AFUR members.

Where a distribution company is making significant improvements to the network, planned interruptions may be necessarily high for a planned period of time and the regulator may wish to relax the limits for this period. The minimum period of notice for a planned outage should be set by the regulator, for example 24 hours.

The method of recording the required data should be agreed by the regulator, and is likely to include collating data from a number of sources, including customers' reports, SCADA records, system operators' reports and customer databases (including metering records).

The figures specified should be subject to continuous improvement by the regulator and distribution system operator.

3.4.3.4 Supply restoration times

Following each unplanned loss of supply the supply restoration time for each group of customers should be recorded. Maximum supply restoration times should be set by the regulator – typical targets for adoption, based on South Africa's experience, would be:

- 30 % of supplies within 1.5 hours,
- 60% of supplies within 3.5 hours,
- 90 % of supplies within 7.5 hours and
- 98% of supplies within 24 hours.

Regulators may also wish to stipulate a restoration time for 100% of customers, for example

- 100% of supplies within 48 hours.

Simpler targets may be expressed in the following form:

- Urban supplies within 12 hours,
- Rural supplies within 24 hours.

3.4.3.5 AENS (average energy not supplied per customer)

AENS is the average energy not supplied per customer per year.

AENS is strictly defined as the total quantity of energy not supplied due to supply interruptions in the year divided by the total number of connected customers.

As an alternative, consideration may be given to using the Average Customer Curtailment Index (ACCI), which is the average energy not supplied per affected customer per year. This index can be difficult to apply if there is inadequate information about the number of customers connected to a given area of the distribution network. In this case, an approximation can be obtained by estimating the total energy not supplied during an outage and taking the ratio of the affected distribution transformer capacity to the total distribution transformer capacity as a proxy for the proportion of the connected customer base affected by the failure. This ratio, when multiplied by the total number of connected customers, gives an approximation for the number of customers affected by the supply failure.

Determination of compliance: The required indices and supply restoration times and percentages should be reported on an annual basis and compared with the previous five years. Indices which fall outside the target limits should be highlighted and discussed.

3.4.4 <u>Criterion: System frequency</u>

Minimum Standard: Generators should be capable of remaining synchronised for changes +3% to - 5% in frequency (IEC 60034-1 and IEC 60034-3). For interconnected systems the frequency should be normally be maintained within ±2.0% of nominal for continuous operation, generators should be able to maintain full output in this range (IEC 61000-2-2, IEC 60034-1 and IEC 60034-3). For island systems, the frequency should normally be maintained within ±2.5% of nominal for continuous operation.

For SAPP the target is to maintain the frequency within 2% of nominal for any credible multiple contingency (to meet IEC 61000-2- 2, , NRS 048-2 edition 3 and PIESA 1048:2007). 1% of nominal for a single contingency (to meet European Standard - EN 50160 and IEEE Recommended Practice 446: 1995). For normal operation the target is to control the frequency with a deviation of less than 0.15 Hz for 95% of the time.

Control Areas within an interconnection should also have performance targets to ensure they are actively participating in frequency control. SAPP has adopted the NERC performance standards in this regard.

Automatic under frequency load shedding is normally used should the frequency go below the 2% target. This is required to prevent blackouts.

Determination of compliance: The number, magnitude and duration of frequency excursion events should be recorded by the Transmission System Operator each year. A frequency excursion event is defined as one where the frequency moves outside the permitted range.

3.4.5 <u>Criterion: Transmission voltage</u>

Minimum Standard: The voltage of all transmission networks at operating voltages of less than 400 kV should be maintained within ±10% of nominal. The voltage of transmission networks operating at voltages of greater or equal to 400 kV should be maintained within ±5% of nominal. Derogations from these limits can be agreed where the normal voltage at a customer connection point is not the nominal voltage.

Determination of compliance: The number, magnitude and duration of voltage excursion events should be recorded by the Transmission System Operator each year. The IEC 61000 4-30 standard should be referenced for taking measurements. A voltage excursion event is defined as one where the voltage at any busbar on the transmission system falls outside the limits. The 10 minute RMS value should be used. PIESA states that no more than two successive 10 minute values should exceed the limits, and any occurrences that contravene this requirement should therefore be highlighted.

3.4.6 **Criterion: Distribution network and delivery point voltages**

Minimum Standard: The voltage of all distribution networks and delivery points should be maintained within ±10% of nominal. Nominal delivery point voltages are assumed to be 230 V; if this is not the case, the ±10% limits need to be modified. An example is shown in the table below. Derogations from these limits can be agreed where the normal voltage at a customer connection point is not the nominal voltage.

Delivery point voltage	Lower limit	Upper limit
220 V	-6%	+10%
240 V	-10%	+6%

Determination of compliance: The number, magnitude and duration of voltage excursion events for the distribution substations and delivery points should be recorded by the distribution system operator each year. A voltage excursion event is defined as one where the voltage at any busbar or delivery point on the distribution system falls outside the prescribed limits.

3.4.7 **Criterion: Voltage Harmonics**

Minimum Standard: The compatibility levels[5] for harmonic voltages in networks at operating voltages less than or equal to 35 kV should be as in IEC 61000-2-2 and IEC 61000-2-12. IEC 61000-3-6 contains a summary of these provisions, which is reproduced in Table 4 below.

Table 4. Compatibility levels for harmonic voltages (in percent of the nominal voltage) in LV and MV power systems

Odd harmonics non multiple of 3		**Odd harmonics multiple of 3**		**Even harmonics**	
Order *h*	**Harmonic voltage %**	**Order** *h*	**Harmonic voltage %**	**Order** *h*	**Harmonic voltage %**
5	6	3	5	2	2
7	5	9	1.5	4	1
11	3.5	15	0.3	6	0.5

[5] As discussed in various references such as IEC 61000, NRS 048 and PIESA 1048 there is a spread of probabilities that a quality of supply parameter will have a specific value. Depending on the parameter it may be possible to define compatibility levels and limits which provide measures of quality at the customers point of supply. The referenced documents set compatibility levels such that they represent the 95% probability levels for the limit of system disturbance. Compatibility levels are specified for voltage harmonics, voltage fluctuation and voltage unbalance.

13	3	21	0.2	8	0.5
17	2	>21	0.2	10	0.5
19	1.5			12	0.2
23	1.5			>12	0.2
25	1.5				
>25	0.2 +1.3(25/h)				
NOTE Total harmonic distortion (THD) 8%					

The planning levels for harmonic voltages at individual connection points should be less than or equal to the compatibility levels and should be determined by each system operator. Typical planning levels for LV systems which would be applicable to systems with a similar design to the UK are given in UK Engineering Recommendation G5/4, an example from which is given below. Procedures for connection of non linear load to a distribution or transmission system should be followed as detailed in IEC 61000-3-6.

Table 5. Planning levels for harmonic voltages in 400 V systems

Odd harmonics non multiple of 3		**Odd harmonics multiple of 3**		**Even harmonics**	
Order	**Harmonic**	**Order**	**Harmonic**	**Order**	**Harmonic**
5	4	3	4	2	1.6
7	4	9	1.2	4	1
11	3	15	0.3	6	0.5
13	2.5	21	0.2	8	0.4
17	1.6	>21	0.2	10	0.4
19	1.2			12	0.2
23	1.2			>12	0.2
25	1.2				
>25	0.2 +0.5(25/h)				
NOTE Total harmonic distortion (THD) 5%					

PIESA 1048 contains compatibility levels for harmonic voltages which are applicable at the EHV and HV levels – these are reproduced below, for reference purposes.

Table 6. Compatibility levels for harmonic voltages at EHV and HV levels

1	2
Harmonic order (h)	**HV and EHV Harmonic voltage (%)**
3	2,5
5	3,0
7	2,5
11	1,7
13	1,7
17	1,2
19	1,2
23	0,8
25	0,8

Determination of compliance: Measurements should be undertaken for a minimum period of one week at the delivery points in accordance with IEC 61000-4-7. The assessment procedure against the planning levels should be as detailed in IEC 61000-3-6, Section 3. Following a customer complaint, measurements should be taken at a delivery point until both the system operator and the customer are satisfied a representative range of harmonic voltages has been determined for the normal range of operating conditions.

In the case of repeated non compliance with the planning levels at a delivery point the supply company and customer should work together to consider system re-configuration or the installation of filters to reduce the harmonic voltage level to within the planning levels given.

The number of delivery points experiencing harmonic voltages outside the planning levels should be recorded on an annual basis.

3.4.8 <u>Criterion: Voltage fluctuation (flicker)</u>

Minimum Standard: The compatibility level for long term flicker severity (P_{lt}) in distribution networks should be 1.0. This corresponds to flicker at the level of perception for 50% of the population when reading with a 60W incandescent lamp.

Determination of compliance: Measurements should be undertaken at the delivery points in accordance with IEC 61000-4-15. The compatibility level for P_{lt} should be compared with the highest measured flicker severity over 95% of the time. Following a customer complaint, measurements should be taken at a delivery point until both the system operator and the customer are satisfied a representative range of P_{lt} figures have been determined for the normal range of operating conditions.

In the case of repeated non compliance at a delivery point the supply company and customer should work together to consider system re-configuration or re-enforcement to reduce the flicker severity to within the compatibility levels given.

The number of delivery points experiencing voltage flicker outside the compatibility levels should be recorded on an annual basis.

3.4.9 Criterion: Voltage unbalance (negative sequence voltage)

Minimum Standard: The compatibility level for voltage unbalance at all voltage levels of the power system should be 3%. The intention is to move towards a compatibility level for voltage unbalance at all voltage levels of 2% over a 5 year period. During the time when compatibility levels are 3%, certain customers (notably industrial customers located in areas of significant domestic demand) may need to be alerted to the fact that higher levels of voltage unbalance would necessitate the selection of higher motor sizes than would otherwise be the case.

The regulator should set a percentage number of sites permitted to be outside the limits each year, for example no more than 5% of all substations should be recorded as being outside the limits. This figure should be subject to continuous improvement by the regulator and transmission system operator.

Determination of compliance: Measurements should be undertaken and voltage unbalance will be calculated according to the definition of voltage unbalance given in IEC 61000-4-30. The compatibility level should be compared with the highest measured unbalance over 95% of the time. Following a customer complaint, measurements should be taken at the delivery point until both the distribution system operator and the customer are satisfied a representative range of voltage unbalance measurements have been captured for the normal range of operating conditions.

In the case of repeated non compliance at a delivery point the distribution system operator and customer should work together to consider system re-configuration or re-enforcement to reduce the voltage unbalance to within the compatibility levels given.

The number of delivery points experiencing voltage unbalance outside the compatibility level should be recorded on an annual basis.

3.4.10 Criterion: Voltage dips

Minimum Standard: Voltage dips should be recorded according to the definitions of dip categories, depth and duration as given in PIESA 1048 and measured according to IEC 61000-4-30. Once a database of voltage dips has been determined for different customer types it may be possible for the regulator to set targets on the acceptable numbers of voltage dips within each category which are subject to continuous improvement.

Determination of compliance: Following a customer complaint, measurements should be taken at a delivery point until both the distribution system operator and the customer are satisfied a representative range of voltage dip measurements have been captured for the normal range of operating conditions. If the voltage dip is causing equipment to malfunction or contactors to drop out then the distribution system operator and customer should work together to determine the cause of the dips and a solution such as equipment compatibility, system re-configuration or re-enforcement to reduce the voltage dips to within acceptable levels.

3.5 Customer interface

3.5.1 <u>**Criterion: Response to requests for new connections or connection modifications**</u>

Minimum standard: The electricity supplier will provide the customer with a quotation for a new supply or modification to an existing connection (e.g. moving a meter) within a number of days of receiving the request. The quotation might stipulate that this part of the network is under construction and connections will be available within a defined period of time. Upon the acceptance of the quotation by the customer, the connection will then be commissioned or altered within a number of days. These response times are detailed in Table 7. The requirement for extensions to the network may be determined where obstacles or technical difficulties exist, or the customers' residence boundary is more than 100 metres away from existing network. MV and HV connections are evaluated on a case by case basis.

Table 7. Time to respond to a request for a new connection

	Time to respond to a request for a quotation (Working days)	Time to provide connection after acceptance of quotation from customer (Working days)
No extension required	10	30
Extension required	30	60

Determination of compliance: In order to measure the performance of response by electricity suppliers, the following data should be logged: date of receipt of the request for a quotation, date quotation is supplied, date quotation is accepted and date of commissioning of connection. Targets should be set in relation to existing levels of performance to achieve continuous improvement. Where records show times outside of these limits, regulators should seek explanations from the utilities.

3.5.2 <u>**Criterion: Frequency of meter readings**</u>

Minimum standard: Credit meters should be read and physically inspected at least once every 6 months, and at regular intervals.

Determination of compliance: The date of meter reading and the percentage of meters read and physically inspected at least every six months should be recorded.

3.5.3 <u>**Criterion: Content of bills**</u>

Minimum standard: Bills should include at a minimum the following information

- Name of consumer, account number and meter number
- Maximum limit of consumption (if applicable)
- Date of previous reading and reading (or estimate) itself

- Date of current reading (or estimate) and value
- Tariff class and rate(s)
- Number of units consumed in each tariff band
- Total cost of electricity consumed plus taxes
- Outstanding balance
- Any other charges and explanation
- Total amount payable now
- Latest payment date (before penalties/disconnection)
- Acceptable methods of payment, opening hours etc.
- Where to get help if you cannot pay, query or dispute the bill (telephone number etc)
- Energy saving tips and other vital information such as tariff adjustment proposals (optional)

Information about tariff rates and, where the meter technology permits, consumption records to date, should be made available to prepayment customers.

Determination of compliance: Examples of customer bill formats should be submitted for regulatory approval on an annual basis.

3.5.4 <u>Criterion: Disconnection due to non-payment</u>

Minimum standard: Customers can be disconnected for non-payment after the payment is due. Utilities may wish to use an alternative arrangement, such as a penalty charge for late payment as apposed to disconnecting. Disconnection should not occur on weekends or public holidays, or on other days which local custom and practice may determine. A customer who has been disconnected due to non-payment should be reconnected by the first working day after settling their account satisfactorily.

Determination of compliance: The date of payment deadlines and receipt of payment should be logged. In cases where disconnections follow, records of the notice sent and the date and time of disconnection should be recorded. In cases where the customer settles the account, the date this takes place should be recorded, as well as the date of reconnection.

3.5.5 <u>Criterion: Provision of vending stations for prepayment meters</u>

Minimum standard: Vending stations for prepayment customers should be within a 10 km radius of each customer, and there should be a vending station for every 2000 customers.

Vending stations should be open (at least) normal working hours during the week, and 08:00 – 12:00 during weekends and bank holidays.

Determination of compliance: A register of the location of vending stations should be maintained, ideally on maps or a Geographic Information System (GIS).

3.5.6 Criterion: Account queries

Minimum standard: A customer who makes an account query should receive a response within 10 working days.

Determination of compliance: The date of receipt of each account query and the date of the electricity supplier's response should be logged.

3.5.7 Criterion: Meter accuracy queries

Minimum standard: A domestic customer who submits a query relating to meter accuracy should receive a response within 15 working days. Within this time the issue should be investigated and the meter accuracy tested if appropriate. Derogations from 15 days should be permitted where access to testing facilities is limited. If the meter is found to be within the required accuracy tolerance then the utility may charge the consumer for the meter accuracy checking, and otherwise the costs will be to the utility's account.

Determination of compliance: The date of receipt of meter accuracy queries and the date of the meter accuracy test should be logged. Records should be maintained of queries raised by customers such that the history of customer complaints can be reviewed.

3.5.8 Criterion: Restoration of supply

Minimum standard: In the event of a fault (under normal conditions i.e. not a natural disaster) which results in a loss of supply to the customer, the electricity supplier should ensure the restoration of supply to 98% of customers within 24 hours of being notified of the fault. Minimum target percentages should be specified for restoration of customers within shorter time periods after a fault is reported. These targets should be set by the regulator based on existing levels of performance. An example for these times can be seen in section 3.4.3.4.

The regulator may wish to specify different time limits for different classifications of customer. An example is shown in Table 8.

Table 8. Restoration times preceding the reporting of a minor fault

	Restoration time (hours)
Urban area	12
Rural area	24

Determination of compliance: The time and date of the reporting of a fault and the time and date of restoration of feeders or individual customers should be recorded. From estimates of customer numbers on a feeder, the percentage of customers disconnected in a given period should be calculated. Regulators may also require recording of the cause of the fault.

3.5.9 Criterion: Response to failure of a fuse or circuit breaker

Minimum standard: When notified by a customer, the electricity supplier should attend to the failure of a fuse within 3 hours on a working day, and within 4 hours otherwise, during daytime hours in at least 95% of cases.

Determination of compliance: The time and date of the notification of a fuse failure and the time and date of the attendance to this by the electricity supplier should be logged. The percentage of fuse failures attended to within the given time should be calculated.

3.5.10 Criterion: Notice for planned interruptions

Minimum standard: The electricity supplier should give the customer at least 48 hours notice when they wish to perform planned maintenance which will result in a loss of supply to the customer. Consideration may also be given to setting limits on the number and duration of planned interruptions, for various connections (overhead, underground) and types of customer.

Determination of compliance: The number of customers who received notification sufficiently in advance (48 hours) should be recorded, and expressed as a percentage of interrupted customers.

3.5.11 Criterion: Response to general complaints

Minimum standard: The electricity supplier should respond to a written complaint from a customer within 10 working days of receiving the complaint. There may be a consumer body appointed to handle complaints that are not satisfactorily resolved by the utility but which do not require referral to the regulator. The consumer body may act as a mediator between customers and utilities, or refer issues onwards to the regulator when required.

Determination of compliance: The date of receipt of the complaint from the customer and the date of response from the electricity supplier should be logged. The percentage of complaints responded to within the time frame of 10 working days should be calculated and recorded.

3.5.12 Criterion: Provision of telephone services

Minimum standard: The electricity supplier should provide a 24 hour telephone service for customers to use in emergencies and to report faults. Regulators may wish to impose standards on time taken to answer telephone calls, lost call rate and time taken to deal with a call.

Determination of compliance: The electricity supplier should report on the number of lines provided for fault reporting, the percentage availability of the telephone line and the number of calls handled in each year. Statistics that are available from centralised call handling PABX systems could be used for this purpose.

3.5.13 Criterion: Making and Keeping appointments

Minimum standard: When the electricity supplier makes an appointment (e.g. for a meter reading), they must offer an appointment within a specified period. For example, a period may be defined as “morning” or “afternoon”. If for any reason the electricity supplier will be unable to keep the appointment, they should give at least 2 working days notice to the customer.

Determination of compliance: The percentage of appointments that take place on the appointed morning or afternoon (or within another declared time period) should be recorded.

3.5.14 Criterion: Response to voltage complaints

Minimum standard: A voltage complaint made by a customer to the electricity supplier should be responded to either with a written explanation of the probable cause, or with a visit to the customers’ premises, within 7 working days.

Determination of compliance: The date of the complaint and the date of the written response or visit should be recorded, with a percentage of responses within 7 working days calculated.

4 References

IEC 61000-3-3: Electromagnetic compatibility (EMC) - Part 3-3, limits – Section 6: assessment of emission limits for distorting loads in MV and HV power system – basic EMC publication.

IEC 61000-4-7: Electromagnetic compatibility (EMC) - Part 4-7: Testing and measurement techniques - General guide on harmonics and interharmonics measurements and instrumentation, for power supply systems and equipment connected thereto.

IEC 61000-4-15: Electromagnetic compatibility (EMC) - Part 4-15: Testing and measurement techniques - Section 15: Flickermeter - Functional and design specifications

IEC 61000-4-30: Electromagnetic compatibility (EMC) – Part 4-30: Testing and measurement techniques – Power quality measurement methods.

PIESA 1048:2007 specification - quality of supply - Voltage characteristics, compatibility levels, limits and assessment methods (Draft 5)

IEC 60034-1, Rotating electrical machines - Part 1 Rating and performance, Edition 10-2, August 1999.

IEC 60034-3, Rotating electrical machines - Part 3 Specific requirements for turbine type synchronous machines, Edition 4, December 1988 and with correction December 2001.

European standard 50160, Voltage characteristics of electricity supplied by public distribution systems, November 1999.

IEEE recommended practice 446-1995.

IEC 61000-2-2, Electromagnetic compatibility Part 2-2: Environment – Compatibility levels for low-frequency conducted disturbances and signalling in public low-voltage power supply systems, 2002.

5 Technical Annex: Calculation Methodologies

5.1 Generation Planning

A long term generation expansion plan should be produced giving details of the timing, capacity and technology of future generation projects that are proposed which will meet the requirements for forecast demand, exports and reserves.

The existing and future system should be defined in the following terms:

- Existing and future generation - availability, capital cost, fixed operation and maintenance costs, fuel prices, efficiencies, energy limitations (where applicable)
- Existing imports/exports
- Existing demand profiles
- Load forecast
- Import/export forecast
- Details of existing demand side management programmes
- Committed investment plan
- Limitations on plant operational flexibility

A probabilistic generation planning programme should be used to produce a generation plan by determining the loss of load probability (LOLP) for alternative generation expansion scenarios and the optimum loss of load expectation (LOLE) for the system.

5.2 Transmission System Planning

Transmission planning studies using computer load flow models should be undertaken to investigate the effects of disconnecting single generating units, transmission circuits, transformers, busbars, shunt capacitors/reactors and other devices on the ability to supply system maximum demand without infringing planning standards for voltages or equipment ratings. The planning studies should also be suitable for undertaking transient stability studies which should be undertaken to investigate the effect of the connection of the power stations in respect of system outages and on the transient stability of the generation and transmission system.

The system model should contain as a minimum the following information about the transmission and generation systems:

- Network topology

- Substations with individual busbar sections modelled
- Impedance data for circuits and transformers
- Transformer tap changing information
- Circuit and transformer ratings
- Series and shunt capacitors and reactors and other compensation equipment
- Automatic compensation control system equipment models
- Generator steady state, transient and sub-transient representation
- Generator inertia data
- Generator control system models
- Generation merit order and spinning reserve
- Maximum and minimum demand load data (lumped at the distribution substations if the model does not include the distribution system)
- Load forecast
- International interconnections if applicable, with representation of the systems suitable for undertaking stability studies i.e. an equivalent inertia.

The model should be validated against actual system records.

Studies shall be conducted to show that the security standards detailed in Table 2 are met for each power station on the system. The model should be validated against actual system records and studies undertaken which consider realistic generation outage scenarios.

5.3 Distribution System Planning

Distribution planning studies using computer load flow models should be undertaken to investigate the effects of disconnecting single distribution circuits, transformers, busbars, shunt capacitors/reactors and other devices on the ability to supply system maximum demand without infringing planning standards for voltages or equipment ratings. The studies shall show that the security standards detailed in Table 2 are met at each voltage level and for each type of system design throughout the distribution system.

The system model(s) should contain as a minimum the following information about sections of the distribution systems to provide a full representation of the different system configurations in use:

- Network topology

- Substations with individual busbar sections modelled
- Impedance data for circuits and transformers
- Transformer tap changing information
- Circuit and transformer ratings
- Shunt capacitors and reactors and other compensation equipment
- Infeed or generator steady state representation
- Customer load data at individual connection points – this should be estimated from historical records of supply point loading, connected customer numbers and types or estimated from the installed transformer capacity and knowledge of the system load levels and load factors.
- Load forecast

The planning studies should consider the following over a 5 or 10 year planning horizon:

- Optimisation of substation location
- Optimisation of transformer loadings
- Optimisation of conductor sizes
- Assessment of feeder open points

5.4 Maintenance planning

The planned maintenance schedules for transmission and distribution should be available for audit by the regulator on an annual basis. Details of joint maintenance planning with the neighbouring transmission system operators shall be documented.

Accurate records of maintenance carried out on the transmission and distribution networks should be recorded at the appropriate reporting level to ensure that a comprehensive log of the plant, equipment and circuits that are disconnected and the associated outage durations is available. This should be prepared on the same basis as the maintenance plan, such that actual performance and planned maintenance schedules can readily be compared.

5.5 Transmission system performance

The Transmission System Operator should complete a record similar to the following for each event:

Event ref No.	Date(s) of event	Event start time	Event finish time	Event duration (hours)	Details of circuits and transformers affected	Name of recording engineer

Event ref No.	Detailed reason for event (to include ref to any related events)	Estimated number of customers affected	Estimated unsupplied energy MWh	Estimated MW demand lost

A separate sheet should be kept for planned outages and unplanned outages.

Planned outages are defined as those which are scheduled for routine maintenance, to allow for the construction of new system assets or enable the connection of new users.

Unplanned outages are defined as forced outages taken by the system operator without sufficient notice or outages due to tripping of circuits due to a fault or other unplanned occurrence.

In order to estimate the unsupplied energy historical records of supply point loading, connected customer numbers and types may be considered. Alternatively, an approximate analysis based on the installed transformer capacity and knowledge of the system load levels and load factors can be used.

5.5.1 <u>System availability index</u>

The Transmission System Operator should calculate the system availability index monthly. Both the planned and unplanned outage records should be used:

$$\text{System availability index} = \frac{\sum_{c=1}^{c=n} \text{number of hours circuit}_c \text{ available in month}}{\text{n x h}} \text{ x } 100$$

Where:

$$\text{n} = \text{total number of circuits in transmission system}$$
$$\text{h} = \text{number of hours in month}$$

5.5.2 System planned unavailability index

The Transmission System Operator should calculate the system planned unavailability index monthly. The planned outage records should be used:

$$\text{System planned unavailability index} = \frac{\sum_{c=1}^{c=n} \text{number of hours circuit}_c \text{ unavailable in month due to planned outage}}{n \times h} \times 100$$

Where:

n = total number of circuits in transmission system
h = number of hours in month

5.5.3 System unplanned unavailability index

The transmission system operator should calculate the system unplanned unavailability index monthly. The unplanned outage records should be used:

$$\text{System unplanned unavailability index} = \frac{\sum_{c=1}^{c=n} \text{number of hours circuit}_c \text{ unavailable in month due to unplanned outage}}{n \times h} \times 100$$

Where:

n = total number of circuits in transmission system
h = number of hours in month

5.5.4 Number of loss of supply incidents

The Transmission System Operator should count the number of incidents that take place on the transmission system which result in a loss of supply to end consumers, both those connected at the transmission level and those connected to the distribution network, on a monthly basis. Both the planned and unplanned outage records should be used and a simple arithmetic count be maintained of the number of loss of supply incidents occurring in each month.

5.5.5 Estimated unsupplied energy

The Transmission System Operator should determine the total estimated unsupplied energy arising from loss of supply due to transmission system incidents on a monthly basis. Both the planned and unplanned outage records should be used. In order to estimate the unsupplied energy historical records of supply point loading, connected customer numbers and types may be considered. Alternatively, an approximate analysis based on the installed transformer capacity and knowledge of the system load levels and load factors can be used.

5.5.6 Average duration of loss of supply incidents

The Transmission System Operator should calculate the weighted average duration of loss of supply incidents monthly.

$$\text{Average duration of loss of supply incidents} = \frac{\text{total energy unsupplied in last 12 months}}{\text{total MW demand lost in last 12 months}}$$

5.5.7 Reporting

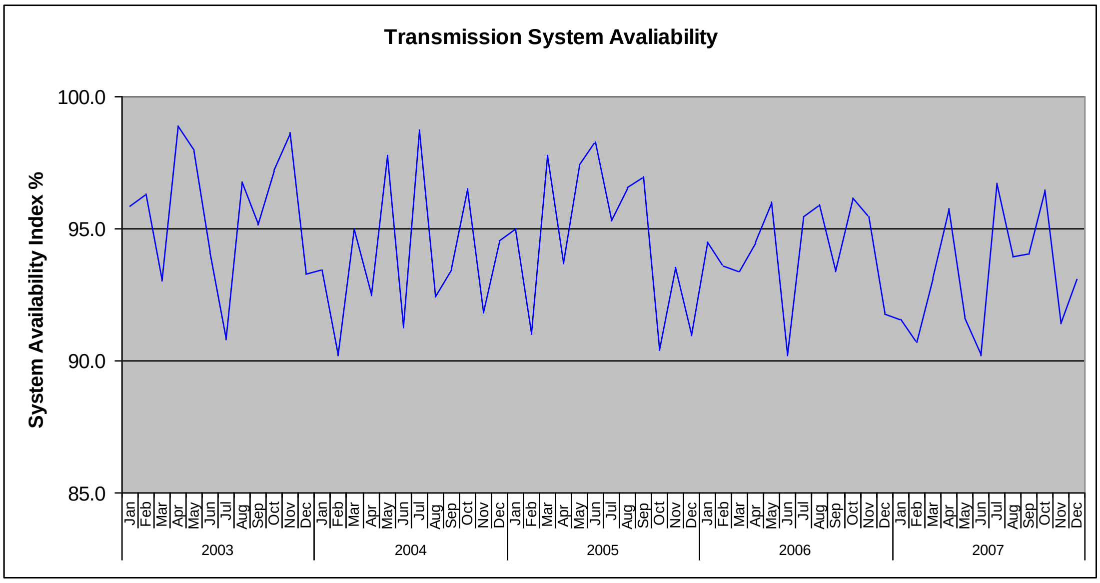
The indices determined in paragraphs 5.5.1 to 5.5.6 should be reported on an annual basis and compared over a sliding window for the previous five years. Indices which fall outside the agreed limits should be highlighted. The summary should be provided to the regulator both as a table and as a number of graphs in the following formats:

Summary Table of Five Year Transmission System Performance - example

Month	system availability index %	system planned unavailability index %	system unplanned unavailability index %	number of loss of supply incidents	estimated unsupplied energy MWh	estimated unsupplied demand MW	average duration of loss of supply incidents h
2003 Jan	*95.9*	*3.3*	*0.8*	*0*	*0*	*0*	*0*
Feb	*96.3*	*2.9*	*0.7*	*1*	*360*	*50*	*7*
Mar	*93.0*	*5.6*	*1.4*	*0*	*0*	*0*	*0*
Apr	*98.9*	*0.9*	*0.2*	*1*	*0*	*0*	*0*
May	*97.9*	*1.7*	*0.4*	*0*	*0*	*0*	*0*
Jun	*94.1*	*4.7*	*1.2*	*2*	*240*	*20*	*12*
Jul	*90.8*	*7.3*	*1.8*	*0*	*0*	*0*	*0*
Aug	*96.8*	*2.6*	*0.6*	*0*	*0*	*0*	*0*
Sep	*95.1*	*3.9*	*1.0*	*1*	*180*	*30*	*6*
Oct	*97.2*	*2.2*	*0.6*	*0*	*0*	*0*	*0*
Nov	*98.6*	*1.1*	*0.3*	*0*	*0*	*0*	*0*
Dec	*93.3*	*5.4*	*1.3*	*0*	*0*	*0*	*0*
2004 Jan	*93.5*	*5.2*	*1.3*	*0*	*0*	*0*	*0*
Feb	*90.2*	*7.8*	*2.0*	*1*	*18*	*10*	*2*
Mar	*95.0*	*4.0*	*1.0*	*0*	*0*	*0*	*0*
Apr	*92.5*	*6.0*	*1.5*	*0*	*1200*	*100*	*12*
May	*97.8*	*1.8*	*0.4*	*2*	*0*	*0*	*0*
Jun	*91.2*	*7.0*	*1.8*	*0*	*0*	*0*	*0*
Jul	*98.7*	*1.0*	*0.3*	*0*	*0*	*0*	*0*
Aug	*92.4*	*6.1*	*1.5*	*3*	*162*	*90*	*2*
Sep	*93.5*	*0.3*	*0.1*	*0*	*0*	*0*	*0*
Oct	*96.5*	*2.8*	*0.7*	*0*	*0*	*0*	*0*
Nov	*91.8*	*6.5*	*1.6*	*1*	*480*	*40*	*12*
Dec	*94.5*	*4.4*	*1.1*	*0*	*0*	*0*	*0*
2005 Jan	*95.0*	*4.0*	*1.0*	*0*	*0*	*0*	*0*
Feb	*91.0*	*7.2*	*1.8*	*2*	*504*	*60*	*8*
Mar	*97.8*	*1.8*	*0.4*	*0*	*0*	*0*	*0*
Apr	*93.7*	*5.0*	*1.3*	*0*	*0*	*0*	*0*
May	*97.4*	*2.1*	*0.5*	*1*	*0*	*0*	*0*
Jun	*98.3*	*1.4*	*0.3*	*0*	*0*	*0*	*0*
Jul	*95.3*	*3.8*	*0.9*	*0*	*0*	*0*	*0*
Aug	*96.5*	*2.8*	*0.7*	*0*	*0*	*0*	*0*
Sep	*97.0*	*2.4*	*0.6*	*2*	*0*	*0*	*0*
Oct	*90.4*	*7.7*	*1.9*	*0*	*108*	*30*	*4*
Nov	*93.6*	*5.2*	*1.3*	*0*	*0*	*0*	*0*
Dec	*91.0*	*7.2*	*1.8*	*0*	*0*	*0*	*0*
2006 Jan	*94.5*	*4.4*	*1.1*	*0*	*0*	*0*	*0*
Feb	*93.6*	*5.1*	*1.3*	*0*	*0*	*0*	*0*
Mar	*93.4*	*5.3*	*1.3*	*0*	*0*	*0*	*0*
Apr	*94.5*	*4.4*	*1.1*	*0*	*0*	*0*	*0*
May	*96.0*	*3.2*	*0.8*	*0*	*0*	*0*	*0*
Jun	*90.2*	*7.8*	*2.0*	*1*	*720*	*50*	*14*
Jul	*95.4*	*3.6*	*0.9*	*0*	*0*	*0*	*0*
Aug	*95.9*	*3.3*	*0.8*	*0*	*0*	*0*	*0*
Sep	*93.4*	*5.3*	*1.3*	*0*	*0*	*0*	*0*
Oct	*96.2*	*3.1*	*0.8*	*0*	*0*	*0*	*0*
Nov	*95.5*	*3.6*	*0.9*	*1*	*0*	*0*	*0*
Dec	*91.8*	*6.6*	*1.6*	*0*	*810*	*90*	*9*
2007 Jan	*91.6*	*6.8*	*1.7*	*0*	*0*	*0*	*0*
Feb	*90.7*	*7.4*	*1.9*	*0*	*48*	*40*	*1*
Mar	*93.1*	*5.5*	*1.4*	*1*	*0*	*0*	*0*
Apr	*95.8*	*3.4*	*0.8*	*0*	*0*	*0*	*0*
May	*91.6*	*6.7*	*1.7*	*0*	*0*	*0*	*0*
Jun	*90.2*	*7.8*	*2.0*	*0*	*108*	*30*	*4*
Jul	*96.7*	*2.6*	*0.7*	*2*	*0*	*0*	*0*
Aug	*93.9*	*4.9*	*1.2*	*0*	*0*	*0*	*0*
Sep	*94.1*	*4.8*	*1.2*	*0*	*0*	*0*	*0*
Oct	*96.5*	*2.8*	*0.7*	*0*	*0*	*0*	*0*
Nov	*91.4*	*6.9*	*1.7*	*0*	*300*	*50*	*6*
Dec	*93.1*	*5.5*	*1.4*	*0*	*0*	*0*	*0*

Data entries in the table are examples only.

Example of graph for 5 year transmission system performance



5.6 Distribution system performance

The Distribution System Operator should complete a record similar to the following for each event:

Event ref No.	Date(s) of event	Event start time	Event finish time	Event duration (hours)	Details of circuits and transformers affected	Group of customers affected (industrial, commercial, residential, urban, suburban)	Name of recording engineer

Event ref No.	Detailed reason for event (to include ref to any related events)	Estimated number of customers affected	Estimated unsupplied energy MWh	Estimated MW demand lost

A separate sheet should be kept for planned outages, unplanned outages and events related to load shedding.

Planned outages are defined as those which are scheduled for routine maintenance, to allow for the construction of new system assets or enable the connection of new users.

Unplanned outages are defined as forced outages taken by the system operator without sufficient notice or outages due to tripping of circuits due to a fault or other unplanned occurrence. The minimum period of notice for a planned outage should be set by the regulator, for example 24 hours.

Momentary interruptions, such as interruptions restored by automatic action (e.g. autoreclose), should be excluded, unless it has been agreed to determine indices for these interruptions. The definition of a momentary interruption used in this standard as being less than 5 minutes is as per IEEE and PIESA standards for voltage levels ≤33kV. Where countries use a different definition, this should be clearly stated when data is being compared among AFUR members.

5.6.1 SAIFI (system average interruption frequency index)

The distribution system operator should determine the average number of supply interruptions per customer arising from loss of supply due to distribution system incidents on a monthly basis. Both the planned, unplanned and load shedding outage records should be used to calculate individual indices and an overall SAIFI each month:

$$\text{SAIFI}_{\textit{planned month m}} = \frac{\text{total number of customer interruptions in month m due to planned outages}}{\text{total number of connected customers}}$$

$$\text{SAIFI}_{\textit{unplanned month m}} = \frac{\text{total number of customer interruptions in month } m \text{ due to unplanned outages}}{\text{total number of connected customers}}$$

$$\text{SAIFI}_{\textit{loadshed month m}} = \frac{\text{total number of customer interruptions in month } m \text{ due to loadshedding}}{\text{total number of connected customers}}$$

$$\text{SAIFI}_{\textit{month m}} = \text{SAIFI}_{\textit{planned month m}} + \text{SAIFI}_{\textit{unplanned month m}} + \text{SAIFI}_{\textit{loadshed month m}}$$

Annual indices should be calculated at the end of each year:

$$\text{SAIFI}_{\textit{planned annual}} = \sum_{m=1}^{m=12} \text{SAIFI}_{\textit{planned month m}}$$

$$\text{SAIFI}_{unplannedannual} = \sum_{m=1}^{m=12} \text{SAIFI}_{unplannedmonth\,m}$$

$$\text{SAIFI}_{loadshedannual} = \sum_{m=1}^{m=12} \text{SAIFI}_{loadshedmonth\,m}$$

$$\text{SAIFI}_{annual} = \text{SAIFI}_{plannedannual} + \text{SAIFI}_{unplannedannual} + \text{SAIFI}_{loadshedannual}$$

Where m = month

5.6.2 <u>SAIDI (system average interruption duration index)</u>

The distribution system operator should determine the average duration of supply interruptions per customer arising from loss of supply due to distribution system incidents on a monthly basis. Both the planned, unplanned and load shedding outage records should be used to calculate individual indices and an overall SAIDI each month:

$$\text{SAIDI}_{planned\ \ month\ \ m} = \frac{\text{sum of customer interruption durations in month } m \text{ due to planned outages}}{\text{total number of connected customers}}$$

$$\text{SAIDI}_{unplanned\ \ month\ \ m} = \frac{\text{sum of customer interruption durations in month } m \text{ due to unplanned outages}}{\text{total number of connected customers}}$$

$$\text{SAIDI}_{loadshed\ \ month\ \ m} = \frac{\text{sum of customer interruption durations in month } m \text{ due to loadshedding}}{\text{total number of connected customers}}$$

$$\text{SAIDI}_{month\,m} = \text{SAIDI}_{plannedmonth\,m} + \text{SAIDI}_{unplannedmonth\,m} + \text{SAIDI}_{loadshedmonth\,m}$$

Annual indices should be calculated at the end of each year:

$$\text{SAIDI}_{plannedannual} = \sum_{m=1}^{m=12} \text{SAIDI}_{plannedmonth\,m}$$

$$\text{SAIDI}_{unplannedannual} = \sum_{m=1}^{m=12} \text{SAIDI}_{unplannedmonth\,m}$$

$$\text{SAIDI}_{loadshedannual} = \sum_{m=1}^{m=12} \text{SAIDI}_{loadshedmonth\,m}$$

$$SAIDI_{annual} = SAIDI_{planned annual} + SAIDI_{unplanned annual} + SAIDI_{loadshed annual}$$

Where m = month

5.6.3 CAIDI (customer average interruption duration index)

The distribution system operator should determine the average duration of each supply interruption per customer who experienced the interruption arising from loss of supply due to distribution system incidents on a monthly basis. Both the planned, unplanned and load shedding outage records should be used to calculate individual indices and an overall CAIDI each month:

$$CAIDI_{planned month m} = \frac{SAIDI_{planned month m}}{SAIFI_{planned month m}}$$

$$CAIDI_{unplanned month m} = \frac{SAIDI_{unplanned month m}}{SAIFI_{unplanned month m}}$$

$$CAIDI_{loadshed month m} = \frac{SAIDI_{loadshed month m}}{SAIFI_{loadshed month m}}$$

$$CAIDI_{month m} = CAIDI_{planned month m} + CAIDI_{unplanned month m} + CAIDI_{loadshed month m}$$

Annual indices should be calculated at the end of each year:

$$CAIDI_{planned annual} = \frac{SAIDI_{planned annual}}{SAIFI_{planned annual}}$$

$$CAIDI_{unplanned annual} = \frac{SAIDI_{unplanned annual}}{SAIFI_{unplanned annual}}$$

$$CAIDI_{loadshed annual} = \frac{SAIDI_{loadshed annual}}{SAIFI_{loadshed annual}}$$

$$CAIDI_{annual} = CAIDI_{planned annual} + CAIDI_{unplanned annual} + CAIDI_{loadshed annual}$$

5.6.4 Supply restoration times

The supply restoration time for each unplanned outage should be tabulated annually in groupings as agreed with the regulator; e.g. time within which certain percentages of supplies are restored or time to restore urban supplies and time to restore sub urban supplies. Information regarding unplanned outages should be provided to the energy supplier.

5.6.5 AENS (average energy not supplied per customer)

The distribution system operator should determine the average energy not supplied per customer per year due to distribution system incidents

$$\text{AENS} = \frac{\text{Total energy not supplied in year}}{\text{Total number of customers connected}}$$

5.6.6 Reporting

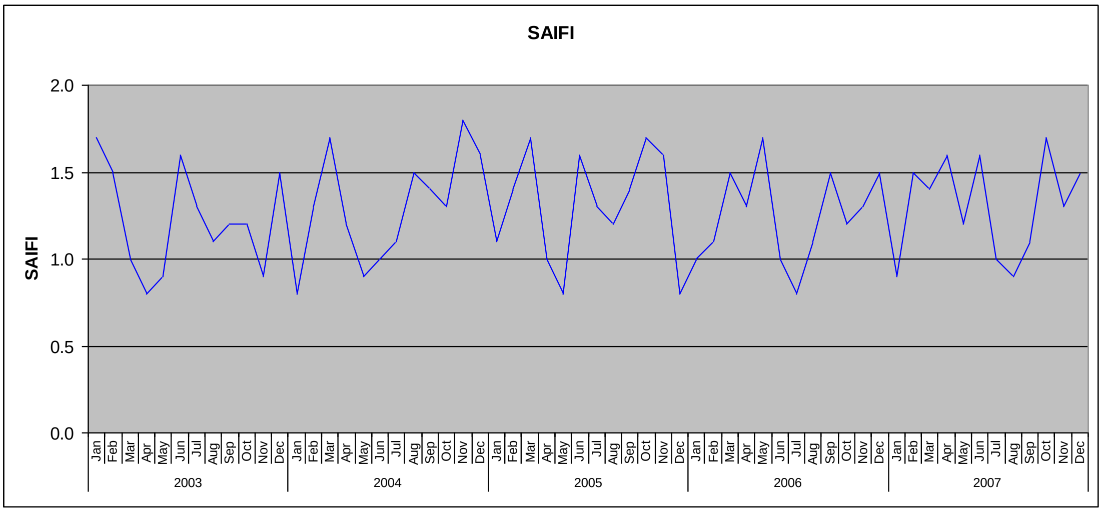
The indices determined in paragraphs 5.6.1 to 5.6.5 should be reported on an annual basis and compared over a sliding window for the previous five years. Indices which fall outside the agreed limits should be highlighted. The summary should be provided to the regulator both as a table and as a number of graphs in the following formats:

Table of distribution system performance summary – example

	Month	SAIFI	SAIDI	CAIDI	AENS MW
2003	Jan	1.7	500	294.1	50
	Feb	1.5	300	200.0	25
	Mar	1.0	150	150.0	40
	Apr	0.8	450	562.5	5
	May	0.9	250	277.8	40
	Jun	1.6	100	62.5	35
	Jul	1.3	550	423.1	20
	Aug	1.1	150	136.4	10
	Sep	1.2	300	250.0	5
	Oct	1.2	400	333.3	15
	Nov	0.9	250	277.8	30
	Dec	1.5	400	266.7	45
2004	Jan	0.8	450	562.5	20
	Feb	1.3	250	192.3	35
	Mar	1.7	100	58.8	40
	Apr	1.2	350	291.7	45
	May	0.9	400	444.4	30
	Jun	1.0	550	550.0	15
	Jul	1.1	350	318.2	5
	Aug	1.5	250	166.7	10
	Sep	1.4	300	214.3	20
	Oct	1.3	450	346.2	35
	Nov	1.8	500	277.8	40
	Dec	1.6	150	93.8	10
2005	Jan	1.1	300	272.7	30
	Feb	1.4	450	321.4	25
	Mar	1.7	250	147.1	40
	Apr	1.0	550	550.0	10
	May	0.8	300	375.0	15
	Jun	1.6	250	156.3	5
	Jul	1.3	400	307.7	30
	Aug	1.2	350	291.7	40
	Sep	1.4	150	107.1	30
	Oct	1.7	400	235.3	10
	Nov	1.6	300	187.5	5
	Dec	0.8	250	312.5	30
2006	Jan	1.0	150	150.0	25
	Feb	1.1	350	318.2	20
	Mar	1.5	450	300.0	15
	Apr	1.3	400	307.7	30
	May	1.7	300	176.5	45
	Jun	1.0	150	150.0	20
	Jul	0.8	250	312.5	5
	Aug	1.1	100	90.9	15
	Sep	1.5	500	333.3	30
	Oct	1.2	350	291.7	25
	Nov	1.3	200	153.8	10
	Dec	1.5	100	66.7	5
2007	Jan	0.9	450	500.0	40
	Feb	1.5	300	200.0	35
	Mar	1.4	250	178.6	25
	Apr	1.6	100	62.5	15
	May	1.2	350	291.7	20
	Jun	1.6	400	250.0	5
	Jul	1.0	250	250.0	10
	Aug	0.9	200	222.2	25
	Sep	1.1	300	272.7	30
	Oct	1.7	500	294.1	40
	Nov	1.3	450	346.2	30
	Dec	1.5	150	100.0	15

Data entries in the tables are examples only.

Example of graph for 5 year SAIFI



Example of table of supply restoration times

	Event Ref No.	Date(s) of Event	Estimated number of customers affected	Supply restoration time for 30% of supplies (hours)	Supply restoration time for 60% of supplies (hours)	Supply restoration time for 90% of supplies (hours)	Supply restoration time for 98% of supplies (hours)	Supply restoration time for 100% of supplies (hours)
	001	*02/01/2002*	*1,000*	*1.5*	*1.5*	*1.5*	*24*	*24*
	002	*15/08/2004 - 16/08/2004*	*100*	*10*	*10*	*10*	*10*	*10*
	003	*30/03/2004*	*200*	*1.5*	*2.5*	*2.5*	*2.5*	*2.5*
	004	*05/04/2005*	*500*	*1.5*	*3.6*	*3.6*	*24*	*24*
	005	*20/05/2005*	*1,000*	*1*	*1*	*1*	*20*	*20*
	006	*14/02/2006*	*900*	*1.2*	*2*	*3*	*30*	*30*
	007	*19/08/2006*	*300*	*1.1*	*1.1*	*2.5*	*18*	*18*
	008	*03/04/2007*	*400*	*0.8*	*3*	*3*	*15*	*15*
	009	*08/06/2007 - 09/06/2007*	*500*	*1.1*	*20*	*20*	*20*	*20*
	010	*24/12/2007*	*1,200*	*1.3*	*3*	*3*	*3*	*3*
2007 average restoration time (hours)				***2.1***	***4.8***	***5.0***	***16.7***	***16.7***
Target restoration time (hours)				*1.5*	*3.5*	*7.5*	*24*	*48*

Data entries in the tables are examples only

5.7 System frequency

The system frequency shall be measured every 10 s for class A measurement performance in accordance with the latest version of IEC 61000-4-30. Class A measurement performance is used where precise measurements are necessary to verify compliance with standards. The basis of this measurement is that an integer number of cycles shall be counted over a 10 s period and the actual duration corresponding to this number of cycles shall be measured. The frequency is then calculated as the ratio of the two numbers.

The system frequency shall be measured at the National Control Centre or at another agreed location.

The number, magnitude and duration of frequency excursion events outside the range specified in Section 3.4.4 should be recorded by the Transmission System Operator each year. A table with a format similar to the example below will be submitted to the regulator annually.

Record No.	Date	Start time of frequency excursion	End time of frequency excursion	Duration of frequency excursion	Extent of frequency excursion with reference to frequency trace recording if applicable	Reason for frequency excursion	Responsible Engineer
F001	*12/2/07*	*08:23*	*08:25*	*2 secs*	*48.1 Hz*	*Sudden trip of 500 MW generator at power station 1 resulted in rapid fall in frequency which was arrested by operation of level 1 of the under-frequency load shedding scheme.*	*J Smith*

Data entries in the tables are examples only

5.8 Transmission voltage

The transmission system r.m.s. voltage shall be measured at the required locations on all three phases in accordance with the latest version of IEC 61000-4-30 over a minimum measurement interval of one week.

The 10 minute r.m.s. value should be used. No more than two successive 10 minute values should exceed the limits specified in Section 3.4.5. The number, magnitude and duration of voltage excursion events should be recorded by the Transmission System Operator each year. A table with a format similar to the example below will be submitted to the regulator annually.

Record of transmission system voltage excursions - example

Record No.	Date	Location	Start time of voltage excursion	End time of voltage excursion	Duration of voltage excursion	Magnitude of voltage excursion with reference to voltage trace recording if applicable	Phases affected	Reason for voltage excursion	Resp. Engineer
V001	*12/2/07-13/2/07*	*Substation A, transformer 1*	*23:00*	*06:00*	*7 hours*	*425 kV*	*Red, Yellow and Blue*	*Transformer 1 at substation A, AVR failed. Light load caused excessive voltage rise.*	*J Smith*

Data entries in the tables are examples only

5.9 Distribution network and delivery point voltages

The distribution system r.m.s. voltage shall be measured at the locations where investigations are required, or general monitoring is taking place, on all three phases or single phase as applicable to the system, in accordance with the latest version of IEC 61000-4-30, over a minimum measurement interval of one week.

The 10 minute r.m.s. value should be used. No more than two successive 10 minute values should exceed the limits specified in Section 5.9. The number, magnitude and duration of voltage excursion events should be recorded by the Distribution System Operator each year. A table with a format similar to the example below will be submitted to the regulator annually.

Record of distribution system voltage excursions - example

Record No.	Date	Location	Start time of voltage excursion	End time of voltage excursion	Duration of voltage excursion	Extent of voltage excursion with reference to voltage trace recording if applicable	Phases affected	Reason for voltage excursion	Resp Engineer
LV001	*12/2/07-13/2/07*	*PMT 0560, distribution circuit lightind3*	*23:00*	*06:00*	*7 hours*	*255 V*	*Red, Yellow and Blue*	*Transformer 1 at substation a, AVR failed. Light load caused excessive voltage rise.*	*J Smith*

Data entries in the tables are examples only

5.10 Voltage Harmonics

Measurements of voltage waveforms should be undertaken of ten minute values for a minimum period of one week at the required delivery points and elsewhere in the system as necessary to gain a full understanding of the harmonic problem under investigation. Measurements should be taken in accordance with the latest version of IEC 61000-4-30 and as defined in the latest version of IEC 61000-4-7 using an instrument capable of undertaking a discrete Fourier transform, or other technique as detailed in the standard.

The number of delivery points experiencing harmonic voltages outside the planning levels should be recorded on an annual basis in a format similar to below:

Record of distribution system voltage harmonic excursions - example

Record No.	Date complaint due to suspected harmonic problem notified	Location	Reason for complaint	Dates of measure - ment	Duration of measure-ment	Results Worst case over measurement period Results outside planning level (delivery points) or compatibility levels (system) shall be highlighted		Solution	Resp. Engineer
						Harmonic order	Harmonic voltage % of fundamental voltage		
H001	*12/2/07*	*PMT 0560, distribution circuit lightind3*	*Customer complaint that small induction motors failing frequently*	*20/2/07- 27/2/07-*	*7 days*	*2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 THD*	*0.5 5 0.3 6 0.3 6 0.2 1.2 0.2 3 0.1 2.5 0.1 0.2 0.1 0.5 0.1 0.3 0.1 0.1 0.1 0.2 0.1 0.3 10.7*	*See full report xxx; customer to install filters measure ments to be retaken.*	*J Smith*

Data in table is for example only

Where measurements are taken at points other than delivery points in the system they should be compared with the appropriate compatibility levels specified in 3.4.7.

5.11 Voltage fluctuation (flicker)

Measurements should be undertaken of 2 hour P_{lt} values for a minimum period of one week at the required delivery points and else where in the system as necessary to gain a full understanding of the flicker problem under investigation. Measurements should be undertaken in accordance with the latest version of IEC 61000-4-30 using a flicker meter as defined in the latest version of IEC 61000-4-15.

The long term flicker severity should be determined from the output of the flicker meter or can be calculated from 12 successive P_{st} values using the following formula:

$$P_{lt} = \sqrt[3]{\frac{1}{12}\sum_{k=1}^{12} P_{st,k}^{3}}$$

Where $P_{st,k}$ is the general term for a consecutive 10 minute short term flicker severity value.

The compatibility level for P_{lt} should be compared with the highest measured flicker severity over 95% of the time. The number of delivery points experiencing voltage flicker outside the compatibility levels given in 3.4.8 should be recorded on an annual basis in a format similar to below:

Record of distribution system excessive voltage fluctuations - example

Record No.	Date complaint due to suspected flicker problem notified	Location	Reason for complaint	Dates of measure-ment	Duration of measure-ment	Results Highest measured P_{lt} over 95% of the time	Solution	Resp. Engineer
F001	*12/2/07*	*PMT 0560, distribution circuit lightind3*	*Customer complaint lights flickering at certain times of the day*	*20/2/07-27/2/07-*	*7 days*	*2%*	*Individual water heater time controllers adjusted in to prevent large changes in load.*	*J Smith*

Data in table is for example only

5.12 Voltage unbalance (negative sequence voltage)

Measurements should be undertaken of 10 minute rms line voltages for a minimum period of one week at the required delivery points and else where in the system as necessary to gain a full understanding of the voltage unbalance problem under investigation. Measurements should be undertaken in accordance with the latest version of IEC 61000-4-30.

The following equations can be used to calculate negative sequence voltage unbalance from the phase voltage measurements:

$$\beta = \frac{V_{ab}^4 + V_{bc}^4 + V_{ca}^4}{(V_{ab}^2 + V_{bc}^2 + V_{ca}^2)^2}$$

$$\text{Negative sequence voltage unbalance} = \sqrt{\frac{1 - \sqrt{3 - 6\beta}}{1 + \sqrt{3 - 6\beta}}}$$

Where V_{ab} = rms voltage phase a to phase b,

V_{bc} = rms voltage phase b to phase c,

V_{ca} = rms voltage phase c to phase a

The compatibility level should be compared with the highest measured unbalance over 95% of the time. The number of delivery points experiencing voltage unbalance outside the compatibility level should be recorded on an annual basis in a format similar to below:

Record of distribution system excessive voltage unbalance - example

Record No.	Date complaint due to suspected voltage unbalance problem notified	Location	Reason for complaint	Dates of measure-ment	Duration of measure-ment	Results Highest measured voltage unbalance over 95% of the time	Solution	Resp. Engineer
UB001	*12/2/07*	*PMT 0560, distributio n circuit lightind3*	*Customer complaint that three phase induction motors running hot and failing frequently*	*20/2/07-27/2/07-*	*7 days*	*4%*	*Rebalance distribution feeder.*	*J Smith*

Data in table is for example only

5.13 Voltage dips

Measurements should be taken over one year at a delivery point in accordance with the latest version of IEC 61000-4-30 and as detailed in the latest version of PIESA 1048. Voltage dips should be characterised according to according to the definitions of dip categories, depth and duration as given in the latest version of PIESA 1048.

A record of the voltage dips should be kept in a format similar to below:

Record of distribution system voltage dips - example

Record No.	Date of measurements	Location	Results		Details of full analysis	Responsible Engineer
			Dip category (PIESA definition)	Number of observed voltage dips		
VD001	*01/01/07 – 31/12/07*	*PMT 0560, distribution circuit lightind3*	*Y X1 X2 S T Z1 Z2*	*5 4 4 2 1 2 3*	*Report on voltage dips at PM0560, lightind3*	*J Smith*

Data in table is for example only

5.14 Customer interface

5.14.1 Response to requests for new connections or connection modifications

The electricity supplier should put in place a customer information system that should allow for the logging of the following data in respect of new connections or connection modifications:

- Date of receipt of the request for a quotation
- Date quotation is supplied by the electricity supplier
- Date quotation is accepted by the customer
- Date of commissioning of connection
- Time to respond to a request for a quotation (Working days)
- Time to provide connection after acceptance of quotation from customer (Working days)

Any response times outside the agreed limits should be highlighted and reasons given.

5.14.2 Frequency of meter readings

The electricity supplier should have in place a billing system capable of recording the following data:

- The date of each individual meter reading / physical inspection
- The interval between meter readings / physical inspection for each meter

The percentage of meters read and physically inspected every six months shall be recorded.

5.14.3 Criterion: Content of bills

The electricity supplier should have in place a billing system that ensures that bills include as a minimum the following information

- Name of consumer, account number and meter number
- Maximum limit of consumption (if applicable)
- Date of previous reading and reading (or estimate) itself
- Date of current reading (or estimate) and value
- Tariff class and rate(s)
- Number of units consumed in each tariff band
- Total cost of electricity consumed plus taxes
- Outstanding balance
- Any other charges and explanation
- Total amount payable now
- Latest payment date (before penalties/disconnection)
- Acceptable methods of payment, opening hours etc.
- Where to get help if you cannot pay, query or dispute the bill (telephone number etc)
- Energy saving tips and other vital information such as tariff adjustment proposals (optional)

5.14.4 Disconnection due to non-payment

The electricity supplier should have in place a billing system that contains the following information:

- Date of payment deadlines for each customer

- Date of receipt of payment for each customer
- Records of the notices sent regarding disconnection to individual customers
- The date and time of disconnection of a customer
- The date a disconnected customer settles an account
- The date of reconnection of a disconnected customer

5.14.5 Provision of vending stations for prepayment meters

A register of the location of vending stations should be maintained by the electricity supplier, ideally on maps or a Geographic Information System (GIS).

5.14.6 Account queries

The electricity supplier should have in place a customer information system allows for the logging of the following data:

- The date of receipt of each account query
- The date of the electricity supplier's response

The time taken to respond to the query shall be recorded and compared to the requirements of the standard. Any times longer than the requirements shall be highlighted.

5.14.7 Meter accuracy queries

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The date of receipt of a meter accuracy query
- The date of the electricity supplier's response

The time taken to respond to the query shall be recorded and compared to the requirements of the standard. Any times longer than the requirements shall be highlighted.

5.14.8 Restoration of supply

The electricity supplier should have in place a customer information system that allows for the logging of the following data, some of which should be obtained from the Distribution System Operator:

- The time and date of the reporting of a fault by a customer

- The time and date of restoration of feeders or individual customers as provided by the Distribution System Operator

- The percentage of customers disconnected in a given period as provided by the Distribution System Operator

A supply restoration time summary should be provided to the regulator in conjunction with the Distribution System Operator.

5.14.9 Response to failure of a fuse or circuit breaker

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The time and date of receipt of notification of a fuse failure

- The time and date of replacement of the fuse

- The time taken to replace the fuse

The percentage of fuse failures attended to within the time specified in the standard should be calculated and compared with the requirements of the standard.

5.14.10 Notice for planned interruptions

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The time and date of issue of notification of planned maintenance

- The time and date of the proposed planned maintenance

- The notice time given

The percentage of customers who received notification within the time required by the standard should be calculated.

5.14.11 Response to general complaints

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The date of receipt of notification of a written customer complaint

- The date of the electricity supplier's response to the complaint

- The time taken respond to the complaint

The percentage of complaints responded to within the time given by the standard should be calculated.

5.14.12 Provision of telephone services

The electricity supplier should have in place a centralised call handling PABX system that allows for the logging of the following data:

- The number of lines provided for fault reporting
- The percentage availability of the telephone line
- The number of calls handled in each year
- Other data as agreed with the regulator such as taken to answer telephone calls, lost call rate and time taken to deal with a call.

5.14.13 Making and keeping appointments

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The time and date of an appointment as agreed with a customer
- The actual time and date of the appointment with the customer

The percentage of appointments that take place within the appointed period as defined in the standard should be calculated.

5.14.14 Response to voltage complaints

The electricity supplier should have in place a customer information system that allows for the logging of the following data:

- The date of receipt of notification of a written customer complaint
- The date of the electricity suppliers response to explain the probable cause or the date of a visit to the customers' premises

The percentage of responses within the appointed period as defined in the standard should be calculated.

5.14.15 Reporting

The performance data determined in Sections 5.14.1 to 5.14.14 should be reported on an annual basis and compared over a sliding window for the previous five years. Indices which fall outside the agreed limits should be highlighted and explanations provided to the regulator as required.