Rationalized User Specification

ELECTRICITY SUPPLY — QUALITY OF SUPPLY

Part 4: Application guidelines for utilities

Preferred requirements for applications in the Electricity Supply Industry
This Rationalized User Specification is issued by the NRS Project on behalf of the User Group given in the foreword and is not a standard as contemplated in the Standards Act, 1993 (Act 29 of 1993).

Rationalized user specifications allow user organizations to define the performance and quality requirements of relevant equipment.

Rationalized user specifications may, after a certain application period, be introduced as national standards.

<table>
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<tr>
<th>Amendment No.</th>
<th>Date</th>
<th>Text affected</th>
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<tbody>
<tr>
<td>1</td>
<td>October 2000</td>
<td>This part of NRS 048 has been amended to include Guidance on voltage regulation planning, which was previously included in NRS 048-2 as a note, and which was deleted as a result of amendment No. 2 to NRS 048-2.</td>
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Foreword

An informal (interim) NRS specification was prepared by the NRS 048 working group in 1997 as a part 4 to NRS 048, to supplement the first editions of parts 1, 2 and 3 with guidelines for utilities. This edition of part 4 replaces the interim part 4, which has been withdrawn, and takes into account the publication of the second edition of part 3 and the publication of part 5.

This part of NRS 048 was prepared by the NRS 048 working group, which comprised the following members:

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NRS 048 consists of the following parts, under the general title Quality of supply standards:

Part 1: Overview of implementation of standards and procedures
Part 2: Minimum standards
Part 3: Procedures for measurement and reporting
Part 4: Application guidelines for utilities
Part 5: Instrumentation and transducers for voltage quality monitoring and recording

Annexes A, B, C, D, E and F are for information only.

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Introduction

The application of NRS 048 is intended to optimize and minimize the combined cost of supply and use of electricity on an overall national basis. In general, historical data does not exist to adequately define quality of supply at points in the electrical networks with statistically valid certainty. NRS 048 sets out to define quality of supply parameters in a manner such that consistent data can be gathered, consolidated, compared and validly interpreted to understand the operation and performance of the networks in South Africa. NRS 048 also sets out, as a first pass, standards which have a credible international reference and quantify a level of network performance which approximates to the needs of developed world industry. The data gathered using the measurement definition of NRS 048 will be used to refine the NRS 048 standards.

The minimum standards set in NRS 048 may well describe levels of quality of supply (QOS) which are perceived as lower than those experienced by individual customers in some areas. Perception of QOS versus reality is indeed a difficult issue. Geographical differentiation of QOS standards is not possible due to the lack of statistically valid historical performance data and is nationally unacceptable as it may prematurely and unreasonably skew investment decisions. NRS 048 has been developed to balance the realistic costs of supply and use of electricity without devolving standards down to the lowest common denominator in indeed raising standards to an inappropriately high level.

This part of NRS 048 provides guidelines to electricity utilities on the application of NRS 048 part 1, 2, 3 and 5, with a view to ensuring that quality of supply issues are dealt with equitably throughout the Electricity Supply Industry (ESI). It needs to be read in conjunction with the other parts of NRS 048 and any directives on quality of supply (QOS) issued by the National Electricity Regulator (NER).

An approach is outlined for the calculation of a specific customer’s fair proportioned allocation of total allowable pollution at a given point of common coupling (PCC). This part of NRS 048 thus serves to prepare annexes to customer supply contracts dealing with the QOS. The document also serves to define what concessions can be made where customers request higher levels of distortion. In such cases the risk that the utilities can accept and the risk that the customer needs to accept are defined.

NRS 048 does not cover safety requirements, network design or equipment performance, nor does it address issues of negligence. The minimum requirements might not apply if unavoidable circumstances are encountered.

NOTE In disputed cases, it would be for the NER (or legal process) to decide whether the circumstances in question were unavoidable.

Examples of such unavoidable circumstances are:

a) war damage, uprising, pilfering, theft, sabotage, attack, malicious damage;

b) damage of equipment caused by accidental and unavoidable occurrences attributable to third parties;

c) damage of material caused primarily by the unusual intensity of a natural event, should the usual precautions to prevent such damage not prevent it or if the precautions could not be taken;

d) extreme atmospheric phenomena which cannot be prevented because of their cause or their extent, and to which electrical networks, especially overhead networks, are particularly vulnerable. Normal lightning activity is excluded;
e) industrial action that prevents normal operation of the network;

f) motor vehicle accident; and

g) where the utility provides a temporary supply to keep customers supplied during maintenance and construction work, or to minimize the extent and duration of a total loss of supply.

**Key words**

Quality of supply; Guidelines; Apportioning.
GUIDELINE

Electricity supply – Quality of supply

Part 4: Application guidelines for utilities

For application in the Electricity Supply Industry

1 Scope

This part of NRS 048 gives guidance to utilities on the application of quality of supply standards. It includes a suggested technical procedure for the connection of a new customer and the evaluation of an existing customer regarding harmonics, voltage unbalance and voltage flicker during contract negotiations. This part of NRS 048 also recommends network planning levels for some parameters for use by utilities in planning to achieve the required compatibility at PCCs. Flicker has been extended to include the concept of a rapid voltage change.

2 Normative references

The following documents contain provisions which, through reference in this text, constitute provisions of this specification. At the time of publication, the editions indicated were valid. All standards and specifications are subject to revision, and parties to agreements based on this specification are encouraged to investigate the possibility of applying the most recent editions of the documents listed below. Information on currently valid national and international standards and specifications can be obtained from the South African Bureau of Standards.


IEEE 519:1992, Recommended practices and requirements for harmonic control in electrical power systems.


NRS 048-1:1996, Electricity supply – Quality of supply – Part 1: Overview of implementation of standards and procedures for applications in the electricity supply industry.


(Amendment No. 1, 1998)
3 Definitions and abbreviations

The definitions and abbreviations given in NRS 048-1 apply.

4 Guidelines

4.1 Implications for utilities

4.1.1 Harmonics and interharmonics

Where available, electromagnetic voltage transformers should be used up to the 25th harmonic (see also annex A of NRS 048-5). Capacitive voltage transformers (CVT) may be used only where special techniques are applied. Under no circumstances should the (uncompensated) secondary output of the capacitive voltage transformer be used for voltage measurement. Where compensation techniques have been proved to meet the above accuracy requirements, the compensated CVT output signal may be used. High-voltage dividers and capacitive bushing tap-off techniques which meet the required accuracy may otherwise be used where electromagnetic voltage transformers are not available.

A utility is responsible for enforcing limits on the injection of harmonics by its customers.

Utilities should advise their customers to specify that the immunity of equipment used in new or upgraded plant be compatible with the harmonic compatibility levels defined in 4.1.1 of NRS 048-2.

Where existing customers’ installations cannot be operated within the maximum harmonic levels permitted in table 1 of NRS 048-2, utilities should negotiate specific arrangements to provide reduced harmonic levels to the customers concerned.

Where a utility installs capacitors, the installation should as far as possible be so designed and operated as to avoid resonances at dominant harmonic frequencies. The resonant frequencies of a network capacitor installation change with network configuration. Network operating states and contingencies should be considered when such designs are undertaken.

Recommended planning levels for harmonics are given in 4.5.1.

Recommended planning levels for interharmonics are given in 4.5.2.

4.1.2 Flicker

A utility is responsible for enforcing limits on the injection of flicker by its customers.

Utilities should advise their customers to specify that the immunity of equipment used in new or upgraded plant be compatible with the flicker compatibility levels defined in 4.2.1 of NRS 048-2.

Where existing customers’ installations cannot be operated within the maximum flicker levels in 4.2.1 of NRS 048-2, utilities should negotiate specific arrangements to provide reduced flicker levels to the customers.
NOTE The effects of flicker are noticed only at the LV point of coupling (i.e. where lighting systems are connected). When this is considered together with recent studies which show that flicker levels are reduced from HV to LV networks, it may result in utilities agreeing on higher \( P_{st} \) levels at HV connection points. The level of flicker reduction from the HV to LV point will differ from network to network and needs to be carefully assessed before flicker levels are established in a QOS contract.

Recommended planning levels for flicker are given in 4.5.3.

Voltage flicker at a point of common coupling can be caused either by single loads which draw continuously fluctuating current (e.g. arc-furnaces, sawmills, crushers), or by the combined effect of several independent loads which draw step changes in current (e.g. motor starting on a rural feeder). For this reason, in order to manage flicker levels at a given PCC, a utility should both limit continuous flicker generated by loads (in terms of short- and long-term flicker severity, \( P_{st} \) and \( P_{lt} \)), and rapid voltage changes caused by load changes (expressed as percentage voltage change).

NOTE The concept of defining rapid voltage changes and appropriate limits is not considered in the first edition of NRS 048-2. Similarly, no recommended planning levels have been included in this part of NRS 048. For guidance, emission limits for rapid voltage changes that could form the basis of limits in contracts with particular customers are given in annex F.

4.1.3 Unbalance

A utility is responsible for limiting the unbalanced load drawn by its customers. A utility shall ensure that its network does not contribute significantly to unbalance conditions.

Utilities should advise their customers to specify that the immunity of equipment used in new or upgraded plant be compatible with the unbalance compatibility levels defined in 4.3.1 of NRS 048-2.

Some customers could have existing equipment such as 3-phase motors which are adversely affected by levels of unbalance below the minimum requirements. In such cases, utilities should consider negotiating to provide reduced levels of unbalance to the customers concerned wherever practicable.

Recommended planning levels for unbalance are given in 4.5.4.

4.1.4 Voltage dips

A utility should ensure that its protection operation is optimized and that network fault performance events are kept to the minimum number possible. Where possible, utilities should aim to better the indicative targets given in annex B. (See 4.4 of NRS 048-2 for the description of the dip window categories Z, T, S, X and Y.)

NOTE 1 Voltage dips are of the most common causes of customer complaints of poor supply quality. In practice some causes of dips are beyond the control of utilities. Special contract conditions of supply or special mitigation techniques within the customer plant, or both, will often be required to meet the requirements of customers with sensitive industrial processes.

NOTE 2 The rate of occurrence of voltage dips is geographically dependent due to differing environmental conditions (lightning, pollution, birds, ground resistivity, burning of sugar cane, etc.). The results of a national study of voltage dip occurrences is expected to provide more specific targets that might be incorporated into a later edition of NRS 048.

4.1.5 Voltage regulation

Where applicable, the guidelines for the calculation of voltage drop in distribution systems for residential areas in NRS 034-1 should be followed.

In the case of systems with a nominal system voltage <500 V, a voltage regulation of \( \pm 10 \% \), as provided for in Regulation 9 of the Electricity Act, 1987 (as amended January 1996), is given as the compatibility level. This makes no provision for any deviation outside those limits, even for short periods. However, the statistical nature of loads is recognized, particularly where there is a significant domestic customer load. Planners will have to make decisions on an economic basis, such that the
infrastructure is optimally utilized, while providing customers with acceptable voltage regulation for the majority of the time. In practice, customers at the extreme ends of feeders might experience voltages outside the prescribed limits for short periods during times of peak or minimum load on those feeders.

In all cases, networks should be designed and operated to meet the requirements in 4.6 of NRS 048-2.

In particular, utilities should ensure that their large customers have voltage regulation and power factor correction equipment that operates correctly, to avoid over or under voltages in a customer’s network being transmitted to the utilities network. This is important not only to avoid other customers being affected by the abnormal voltage, but also to ensure that the life expectancy of plant, particularly transformers, is not reduced. (This can have a consequential effect on the QOS through forced interruptions due to premature plant failure.)

For example, as can be the case with arc furnaces with switched capacitor banks, when the load is switched off, the capacitor banks voltage rises, causing the utility’s transformer to be over-excited from the secondary windings.

It is therefore essential that utilities ensure that, where customers have capacitive compensation equipment installed, the customer has also installed protection or control devices that will limit over-excitation of supply transformers to within their design parameters.

An illustration of the rapid deterioration of transformer life (mean time to failure) with excessive operating voltage \(U\) is given in figure 1.

![Figure 1 – Illustration of the rapid deterioration of transformer life with excessive operating voltage](image)

### 4.1.6 Frequency

Most local utilities have no control over frequency. Generation capacity and transmission, operation and design should meet the load requirements.

**NOTE** Under-frequency load shedding will be by agreement between a utility and its customers, where practicable. In general, the generation authority will impose load shedding on the distributing utilities and will not often be able to advise and obtain the agreement of customers.
4.1.7 Instrumentation

To comply with the requirements of the NER, utilities are obliged to install at least sufficient instrumentation for monitoring purposes according to the sample sizes and other criteria specified in NRS 048-3. In addition, it might be useful for utilities to provide instruments to monitor at their bulk supply points. Utilities might also need to consider acquiring additional instrument(s) for roving monitoring or for troubleshooting.

NRS 048-5 specifies three types of instruments for voltage monitoring and recording that meet the requirements for measuring the parameters for site categories 1 to 5 (see 4.2 of NRS 048-3). NRS 048-5 specifies appropriate environmental tests for the instruments and utilities should ensure that instrument suppliers demonstrate compliance with NRS 048-5 through certified conformance tests from an accredited test laboratory.

For each category of sites 1 to 6 (see 4.2 of NRS 048-3), the sample size is determined as a percentage of the number of customers connected to sites of that category in the utility’s area of supply. The percentages are given in table 1 of NRS 048-3.

An example of how to determine the instrumentation requirements for each site category is shown in Annex D.

4.1.8 Data collection and data analysis

4.1.8.1 General

Utilities should integrate the collection and management of the data required by the NER relating to their plant, customers and actual performance, which is detailed in NRS 048-3, with their normal operating and management information practices. This will allow the utility to benefit from the regular analysis of this information and to minimise the effort required to complete the annual submission to the NER.

The information to be collected and managed fall in three categories:

a) network statistics;

b) forced interruption statistics; and

c) site measurement statistics.

4.1.8.2 Network statistics

It is expected that all utilities will already have systems in place to record the ongoing additions and reductions of plant and customers to their network, but cognizance shall be taken of the various categories of network and supply voltage levels under which these statistics have to be reported.

4.1.8.3 Forced interruption statistics

The method of collection and the management of data on forced interruption statistics will vary from utility to utility but, in all cases, it is recommended that the following be included as part of the permanent record of each incident affecting networks above 1 kV. This is principally for the utility’s own purposes but will also provide the base data for the forced interruption reports required by the NER. (Although not required for the annual submission to the NER, it is expected that the utility would have separate and similar records for incidents affecting their LV networks and connections to customers.) Reference may be necessary to NRS 048-3 for clarification of some of the terms and headings used below.
# MV network

- **date/time of incident** – see note 1
- **name of circuit affected**
- **cause (brief details)**
- **protection operated**
- **capacity lost (kVA)** – see note 2
- **date/time of partial restoration** – see note 4
- **capacity of partial restoration** – see note 4
- **date/time of full restoration**
- **forced interruption index** – see note 5
- **network category** – see note 7
- **source of interruption** – see note 9
- **category of incident** – see note 11
- **major customer affected** – see note 12

# High/medium voltage network

- **date/time of incident** – see note 1
- **name of circuit affected**
- **cause (brief details)**
- **protection operated**
- **load lost (MVA or MW)** – see note 3
- **date/time of partial load restoration** – see note 4
- **capacity of partial load restoration** – see note 4
- **date/time of full restoration**
- **forced interruption index** – see note 6
- **network voltage category** – see note 8
- **source of interruption** – see note 10
- **category of incident** – see note 11
- **major customer affected** – see note 12

## Notes

**NOTE 1** First customer complaint or alarm received.

**NOTE 2** Determined by summing the rated capacity of all MV/LV transformers affected.

**NOTE 3** Actual loss of load, determined by measurement or assessment.

**NOTE 4** Required if the utility wishes to take this into account in the calculation of the forced interruption index which would otherwise be based on the product of the full capacity/load loss and the time taken to full restoration. Where this is to be used, it is recommended that the restored capacity/load be recorded as a percentage of the initial loss in practical incremental steps.

**NOTE 5** Calculated as detailed in NRS 048-3. A utility might find it more convenient and more suitable for their own monthly performance comparisons to maintain this record in the form of kVA-hours and only divide by the total installed capacity of transformers on this category of network (i.e. \( T \)) when compiling the annual submission to the NER.

**NOTE 6** System-minutes calculated as detailed in NRS 048-3.

**NOTE 7** One of four categories (Residential established, Residential developing, Commercial/small industrial or Rural overhead).

**NOTE 8** One of four categories (see NRS 048-3), including a category for forced interruptions due to faults at voltages of 22 kV and below where these occur at a major substation with a higher primary voltage.

**NOTE 9** Provides for the differentiation of forced interruption indices associated with faults on the MV distribution network itself, from faults on the utility’s own higher voltage networks, or interruptions of a bulk supply from another utility, or both.

**NOTE 10** Provides for the differentiation of forced interruption indices associated with faults on the utility’s network from interruptions of the bulk supply from another utility.

**NOTE 11** One of six categories (see NRS 048-3) to best fit the primary cause of the forced interruption. This is only required by the NER where major supply interruptions are to be reported but it is recommended that all incidents be categorized for the utility’s own records and analysis of system performance.

**NOTE 12** Large/strategic end-user as defined by the utility. Forced interruptions affecting large end-users with a notified maximum demand in excess of 5 MVA need to be reported to the NER.

It is recommended that a computer system be used for the collection of this data and for the counting and summation of the elements of each fault that will constitute the performance statistics required for the annual submission to the NER (namely, network category or network voltage category, forced interruption indices, source of interruption and category of incident). The system should have the facility for various on-line enquiries and the automatic production of standard reports (including reports with content to match the statistics required by the NER) at the end of each month and year. If the system is not computerised, it is recommended that these statistics be collated as a daily routine to facilitate the month-end and then year-end reports.
In either case, information on major supply interruptions as defined by the utility shall be extracted from the above database although only supply interruptions in excess of five system-minutes need to be reported to the NER.

4.1.8.4 Site measurement statistics

For categories 3, 4 and 5 sites as defined by table 1 of NRS 048-3, it is expected that the output of the instrumentation used will be limited to the following which will result in minimal data management:

a) number of interruptions (forced and planned);

b) sum of all supply interruption durations;

c) number of days that voltage regulation limit was exceeded – above limit
   – below limit; and

d) sum of the periods that the voltage regulation limit was exceeded – above limit
   – below limit.

For categories 1 and 2 sites, the information required by the NER is also essentially a total count and duration of out-of-limit incidents and the sophistication of the data collection and data management systems introduced by the utility will therefore be determined primarily by the number of measuring sites and the utility's own requirement for useful planning and management information. The facility to download data from remote sites via telephone connections is recommended. Utilities should also make use of such information as the occurrence of voltage dips and interruptions, available from some energy meters.

Where practical, the database for the site measurements should be linked to the database for the forced interruption statistics detailed under 4.1.8.3 in order that an incident such as a voltage dip can be readily linked to a fault on the network and can be analysed in terms of primary cause, network category, etc.

4.1.9 Reporting to the NER

The information required by the NER is specified in NRS 048-3.

If the licensee installs more than the minimum instrumentation prescribed in NRS 048-3, the licensee is required to report to the NER information from all the instrumentation. That is, there should be no selectivity in the information reported to the NER.

4.2 Obligation of utilities

Utilities have obligations to their customers in terms of QOS which are now better defined in NRS 048 than in the past. These obligations remain constrained by reality and national imperatives and might be modified or supplemented by conditions set out in contracts with particular customers.

It is not possible for utilities or the NER to guarantee to maintain QOS at historically perceived levels owing to the need to expand networks and increase their utilization. Further, owing to the lack of valid historical data on performance, it is not possible to undertake to maintain QOS on a broad network basis. Specific commitments in respect of QOS are possible and are usually the subject of contracts with customers. Utilities, however, do have and must accept an obligation not to allow QOS performance to deteriorate unreasonably and in a general way. NRS 048 is not intended to be used as a license to lower network quality or to raise tariffs.
In some cases customers might need a quality of supply which exceeds the minimum network quality specified in NRS 048 and it is not economically viable or justified to achieve the necessary quality within the supply networks. In these cases it is appropriate and expected that utilities will offer customers “behind-the-meter” solutions to their QOS needs. Depending on the specific merits of the case it might be appropriate for the customer, the utility or both to invest in such solutions. In general, such solutions should be designed to minimize cross-subsidization and free-rider effects. “Behind-the-meter” solutions are highly effective in terms of national economic impact and their ability to enhance the compatibility of customer plant with electric networks. Guidance on the classification of industrial customers’ plant in this regard is given in IEC 61000-2-4. An extract from this specification is given in annex C.

4.3 Procedures for apportioning quality of supply parameters

A large load connected to the HV network can have as large an effect on a specific group of customers as a smaller load connected closer to this group of customers at MV or LV. This implies that emission levels need to be co-ordinated from the high voltage busbar to the low voltage busbar (see figure 2).

![Diagram showing emission co-ordination from EHV to LV](image)

Figure 2 – Emission co-ordination from EHV to LV showing the contribution at each voltage level to the total LV level

Any of the following apportioning procedures can be used:

a) IEC 61000-3-6 (harmonics);  
b) IEC 61000-3-7 (flicker); and  
c) IEEE 519.

Utilities will require a methodology to apply apportioning procedures in the establishment of contractual emission levels. Where appropriate, utilities should advise their customers of the apportionment procedures used and the methodology and other criteria used to establish the contractual emission levels. A methodology that uses the IEC apportionment procedures and which has been applied by Eskom is given in annex F.

If the utility is planning to make supply available to a large customer whose plant has the potential for polluting the supply, and if a utility does not have the necessary expertise to apply such apportioning procedures or to establish contracts for emission levels, consideration should be given to making use of quality of supply specialists to assist in drawing up such supply contracts.
4.4 Establishing obligations of licensees and customers in a supply contract

4.4.1 General

Where appropriate, in particular for key industrial customers, quality of supply requirements should be set out in supply contracts.

A model for establishing such agreements is set out in annex A.

4.4.2 Contractual implications for flicker

Flicker emission levels are defined in terms of $P_{st95}$ (daily) and $P_{lt}$ (max).

The fault level under which these flicker levels are specified shall be linked to the flicker emission levels. This fault level is usually the fault level under normal (healthy) network conditions. Where the fault level is reduced due to line outages, the higher flicker levels should not be excessive. In some cases it might be necessary to specify alternate flicker levels for low fault level conditions.

4.4.3 New customers

The emission parameters are required at an early stage in the design process so that equipment specifications can be correctly developed. As far as practicable, the following guidelines should be followed:

a) all official correspondence should be through a specified customer liaison officer;

b) all documentation used in the correspondence should be clearly dated;

c) the fault level conditions for which the parameters are specified should be clearly stated at the beginning of the negotiation process;

d) any changes to fault levels or to voltage quality parameters should be clearly communicated as being the latest figures;

e) the contractual clauses should as far as possible be finalized before the customer equipment specifications are issued. The customer should be made aware of any pending clauses that could affect the equipment meeting the utility requirements; and

f) all parameters should be communicated and agreed to by the relevant engineer(s) and operations manager(s).
4.5 Recommended planning and emission levels

4.5.1 Recommended planning levels for harmonic voltages

The indicative values given in table 1 should be used as recommended planning levels for harmonic voltages unless the utility has established its own recommended planning levels.

Table 1 – Indicative values of planning levels for harmonic voltages
(as a percentage of the rated voltage of the power systems)

<table>
<thead>
<tr>
<th>Order</th>
<th>Odd harmonics (non-multiples of 3)</th>
<th>Odd harmonics (multiples of 3)</th>
<th>Even harmonics</th>
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<tbody>
<tr>
<td>h</td>
<td>MV</td>
<td>HV/EHV</td>
<td>h</td>
</tr>
<tr>
<td>5</td>
<td>5,0</td>
<td>2,0</td>
<td>3</td>
</tr>
<tr>
<td>7</td>
<td>4,0</td>
<td>2,0</td>
<td>9</td>
</tr>
<tr>
<td>11</td>
<td>3,0</td>
<td>1,5</td>
<td>15</td>
</tr>
<tr>
<td>13</td>
<td>2,5</td>
<td>1,5</td>
<td>21</td>
</tr>
<tr>
<td>17</td>
<td>1,6</td>
<td>1,0</td>
<td>&gt; 21</td>
</tr>
<tr>
<td>19</td>
<td>1,2</td>
<td>1,0</td>
<td>12</td>
</tr>
<tr>
<td>23</td>
<td>1,2</td>
<td>0,7</td>
<td>&gt; 12</td>
</tr>
<tr>
<td>25</td>
<td>1,2</td>
<td>0,7</td>
<td></td>
</tr>
<tr>
<td>&gt; 25</td>
<td>0,2+</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>0,5 h</td>
<td>0,5 h</td>
<td></td>
</tr>
</tbody>
</table>

NOTE: Total harmonic distortion (THD): ≤ 6,5 % in MV networks and ≤ 3 % in HV networks.

4.5.2 Recommended planning levels for interharmonic voltages

The indicative values given in table 2 should be used as recommended planning levels for interharmonic voltages unless the utility has established its own recommended planning levels.

Table 2 – Indicative values of planning levels for interharmonic voltages
(as a percentage of the rated voltage of the power systems)

<table>
<thead>
<tr>
<th>Supply</th>
<th>Interharmonic voltage %</th>
</tr>
</thead>
<tbody>
<tr>
<td>HV/EHV</td>
<td>0,2</td>
</tr>
<tr>
<td>MV</td>
<td>0,2</td>
</tr>
</tbody>
</table>

4.5.3 Recommended planning levels for flicker emissions

The indicative values given in table 3 should be used as recommended planning levels for flicker emissions unless the utility has established its own recommended planning levels.

Table 3 – Indicative values of planning levels for flicker emissions

<table>
<thead>
<tr>
<th>Supply</th>
<th>P&lt;sub&gt;n95&lt;/sub&gt; (daily)</th>
<th>P&lt;sub&gt;nmax&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>HV/EHV</td>
<td>0,8</td>
<td>0,6</td>
</tr>
<tr>
<td>MV</td>
<td>0,9</td>
<td>0,7</td>
</tr>
</tbody>
</table>
Proportionally higher planning levels are recommended where the flicker reduction factor from HV to LV is known.

### 4.5.4 Recommended planning levels for unbalance

The indicative values given in table 4 should be used as recommended planning levels for voltage unbalance unless the utility has established its own recommended planning levels.

**Table 4 – Indicative values of planning levels for unbalance**

<table>
<thead>
<tr>
<th>Supply</th>
<th>$UB_{50}$ (daily)</th>
</tr>
</thead>
<tbody>
<tr>
<td>HV/EHV</td>
<td>1,0</td>
</tr>
<tr>
<td>MV</td>
<td>1,5</td>
</tr>
</tbody>
</table>
Model contract for establishing Quality of Supply obligations of licensees and customers in a supply contract (where appropriate)

A.1 Voltage quality – the licensee’s obligation

A.1.1 The LICENSEE shall maintain the voltage quality of the supply to the CUSTOMER in accordance with its reference documentation, NRS 048 or such other standards as may be prescribed by the National Electricity Regulator from time to time.

A.1.2 In the event of the limits as specified in NRS 048-2 or the Licensee’s standard referred to in paragraph A.1.1 being exceeded by the LICENSEE, the LICENSEE shall take appropriate measures to rectify the voltage quality as soon as is practicable.

A.1.3 The LICENSEE shall at its own cost take the necessary corrective action when the sum of consumer interaction at the point of common coupling exceeds the limits as specified in NRS 048-2 or the Licensee’s standard referred to in A.1.1, provided that all consumers connected to the point of common coupling have complied with their individually allocated apportionment.

A.2 Voltage quality – the customer’s obligation

A.2.1 The CUSTOMER shall ensure that any voltage distortions caused by its load or equipment shall not at any time exceed the limits specified in A.2.4, A.2.5 and A.2.6 (the prescribed limits having been determined in accordance with NRS 048-2 or the Licensee’s documentation referred to in paragraph A.1.1).

A.2.2 The quality of supply limits specified in A.2.4, A.2.5, A.2.6, A.3.1 and A.3.2 are based on the following fixed values:

a) Minimum design operating fault level (three-phase): .......... kA

...........................................kiloampere)

b) Maximum design loading: .......... MVA

........................ megavolt ampere)

A.2.3 The quality of supply limits specified in A.2.4, A.2.5, A.2.6, A.3.1 and A.3.2 shall, if necessary, be revised if any of the fixed values in A.2.1 change.

A.2.4 The point of common coupling shall be the ...................... kV busbar at the LICENSEE’S ...................... Substation under normal operating conditions.
A.2.5 The maximum allowable harmonic current injection from the CUSTOMER at the point of common coupling shall be:

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
<th>7</th>
<th>8</th>
<th>9</th>
<th>10</th>
<th>11</th>
<th>12</th>
<th>13</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (A)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>14</th>
<th>15</th>
<th>16</th>
<th>17</th>
<th>18</th>
<th>19</th>
<th>20</th>
<th>21</th>
<th>22</th>
<th>23</th>
<th>24</th>
<th>25</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current (A)</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

A.2.6 The maximum permissible contribution to flicker at the point of common coupling shall be:

a) short term flicker (determined over a 10 min period), \( P_{st} = \) .................

b) long term flicker (determined over a 2 h period), \( P_{lt} = \) .................

A.2.7 The maximum permissible contribution to voltage unbalance at the point of common coupling shall be:

Percentage voltage unbalance = .................

A.2.8 Should any one of the limits specified in A.2.4, A.2.5 and A.2.6 be exceeded, the CUSTOMER shall be required to reduce loading or install corrective equipment at its own expense or take such other measures as might be necessary to reduce the voltage distortion caused by the CUSTOMER’S load or equipment within the specified limits. The LICENSEE shall, in the event of an infringement by the CUSTOMER of the limits as specified herein, inform the CUSTOMER thereof by facsimile in order that corrective measures can be implemented by the CUSTOMER without delay.

Corrective measures shall be implemented by the CUSTOMER immediately after an infringement has occurred or where circumstances justify it within a period of time as may be agreed between the parties. If agreement on the period to be allowed for the CUSTOMER to correct any infringement of the specified limits cannot be reached within 30 (thirty) days of the infringement occurring, the period shall be determined by arbitration.

A.2.9 The CUSTOMER shall give adequate notice in writing to the LICENSEE of intended extensions or upgrading of the CUSTOMER’S plant or the installation of power factor correction equipment and/or any other changes which may impact the power quality or impedance at the point of common coupling to the LICENSEE system (or a combination of these) to enable countermeasures to be taken time-ously.

A.2.10 Customers shall install, operate and maintain suitable overvoltage protection equipment.
A.3 Voltage dips

A.3.1 The LICENSEE shall strive to minimize the number of voltage dips that could cause production disruptions, and to this end shall ensure that the total number of non-coincidental voltage dips category Z (see NRS 048-2) recorded at the point of common coupling in any 12 (twelve) consecutive months does not exceed ........ (............... on the understanding that

a) all voltage dips caused by force majeure or those originating from the CUSTOMER’S load or equipment due to the starting of large loads or faults within the CUSTOMER’S electrical installation, are specifically excluded; and

b) the maximum permissible number of voltage dips specified above, may be subject to revision if the minimum design operating fault level specified in paragraph A.2.1 changes.

In the event of the total number of voltage dips in any 12 (twelve) consecutive months exceeding the maximum number of occurrences as specified above, the LICENSEE shall take appropriate measures to rectify the situation as soon as is practicable.

A.3.2 The CUSTOMER shall ensure that voltage dips of category Z originating from its load or equipment due to the starting of large loads or faults within its electrical installation, as recorded by the LICENSEE at the point of common coupling in any 12 (twelve) consecutive months, does not exceed ........ (......). This maximum permissible number of voltage dips originating from the CUSTOMER’S electrical installation shall be subject to revision if the minimum design operating fault level specified in paragraph A.3.1 changes. Should the specified maximum permissible number of voltage dips be exceeded, the LICENSEE shall inform the CUSTOMER thereof by facsimile in order that corrective measures may be taken by the CUSTOMER without delay.

A.3.3 With reference to paragraph A.3.1 and A.3.2, the maximum permissible number of voltage dips shall be reviewed annually by the CUSTOMER and the LICENSEE and joint and separate actions taken to achieve a mutually acceptable frequency of voltage dip occurrences.

A.4 Measurement of quality of supply

A.4.1 The LICENSEE shall monitor the quality of supply (continuity, voltage quality and voltage dips) at the point of common coupling and the LICENSEE and the CUSTOMER shall collaborate in drawing up appropriate operational procedures to facilitate the monitoring and reporting of the quality of supply. The LICENSEE shall install appropriate metering equipment at the said point of common coupling for this purpose and the cost thereof shall be for the account of the CUSTOMER.
Indicative targets for the number of voltage dips per year

Table B.1 – Indicative targets for the number of voltage dips per year for each category of dip window (see figure B.1)

<table>
<thead>
<tr>
<th>Network voltage range (see note)</th>
<th>Dip window category</th>
<th>Number of voltage dips per year</th>
</tr>
</thead>
<tbody>
<tr>
<td>6,6 kV to ≤ 44 kV</td>
<td>Z</td>
<td>10</td>
</tr>
<tr>
<td>6,6 kV to ≤ 44 kV rural</td>
<td>Z</td>
<td>20</td>
</tr>
<tr>
<td>&gt; 44 kV to ≤ 132 kV</td>
<td>Z</td>
<td>5</td>
</tr>
<tr>
<td>220 kV to ≤ 765 kV</td>
<td>Z</td>
<td>2</td>
</tr>
</tbody>
</table>

NOTE The network voltage is not necessarily the voltage at which the customer takes supply. It may be the voltage of the network that feeds the point of common coupling. Therefore, the set of Z, T, S, X and Y values applicable to a customer should be evaluated in each case, taking account of the network configuration supplying that customer.

Magnitude of voltage depression
(Decrease below nominal)

Figure B.1 – Voltage dip window (extracted from NRS 048-2)
Electromagnetic environment classes

Several classes of electromagnetic environment are possible, but in order to simplify their use, only three are considered and defined in this publication; they are as follows:

Class 1: This class applies to protected supplies and has compatibility levels lower than public network levels. It relates to the use of equipment very sensitive to disturbances in the power supply, for instance the instrumentation of technological laboratories, some automatization and protection equipment, some computers.

NOTE 1 Class 1 environments normally contain equipment which requires protection by such items as uninterruptible power supplies (UPS), filters, or surge suppressors.

NOTE 2 In some cases highly sensitive equipment may require compatibility levels lower than the ones relevant to class 1 environments. The compatibility levels are to be agreed case by case (controlled environment).

Class 2: This class applies to PCCs and to IPCs in industrial environments in general. The compatibility levels of this class are identical to those of the public network; therefore components designed for application in public networks may be used in this class of industrial environment.

Class 3: This class applies only to IPCs in industrial environments. It has higher compatibility levels than class 2 for some disturbance phenomena. For instance, this class should be considered when any of the following conditions are met:

a) a major part of the load is fed through converters;

b) welding machines are present;

c) large motors are frequently started; and

d) loads are rapidly varying.

NOTE Supply to highly disturbing loads, such as arc-furnaces and large converters which are generally supplied from a segregated bus-bar, frequently has disturbance levels in excess of class 3 (harsh environment). In such special situations the compatibility levels must be agreed upon.

The class applicable for new plants and extension of existing plants cannot be made a priori and should relate to the type of equipment and process under consideration.
Annex D

(informative)

An example of instrumentation requirements for each site categorization

Consider a utility (distributor) with 50,000 domestic and commercial (LV) customers, 2,000 of which are considered to be in a developing area and 48,000 in a developed area; 1,000 customers taking supply from an 11 kV rural network (LV and MV customers), 40 customers in urban areas taking supply at between 1 kV and 44 kV, and 1 customer taking supply at 88 kV.

The distributor has two 132 kV intake points.

Table D.1 – Instrumentation requirements by category of site

<table>
<thead>
<tr>
<th>Category of site (see NRS 048-3)</th>
<th>Number of sites to be monitored (based on table 1 in NRS 048-3)</th>
<th>Instrument type (see NRS 048-5)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>1 (see note 1)</td>
<td>C</td>
</tr>
<tr>
<td>2</td>
<td>3 (see note 2)</td>
<td>B</td>
</tr>
<tr>
<td>3</td>
<td>3 (see note 3)</td>
<td>A</td>
</tr>
<tr>
<td>4</td>
<td>5 (see note 4)</td>
<td>A</td>
</tr>
<tr>
<td>5</td>
<td>3 (see note 5)</td>
<td>A</td>
</tr>
</tbody>
</table>

NOTE 1 Category 1 site – only 1 customer. Therefore, only 1 site needs to be monitored.
NOTE 2 Category 2 site – 2% of 40 customers is 0.8. Therefore, only 1 site needs to be monitored.
NOTE 3 Category 3 site – 0.01% of 1,000 customers is 0.1. However, minimum of 3 sites need to be monitored.
NOTE 4 Category 4 site – 0.01% of 4,800 customers is 4.8. Hence, 5 sites need to be monitored.
NOTE 5 Category 5 site – 0.01% of 2,000 customers is 0.2. However, minimum of 3 sites need to be monitored.

Minimum requirements for monitoring instruments will therefore be:

a) 11 type A instruments for category 3, 4 and 5 sites;
b) 3 type B instruments for category 2 site; and
c) 1 type C instrument for category 1 site.

With 40 MV customers in urban areas it could be considered good practice to further provide for an additional roving meter. This should be a type C instrument as some investigation of harmonics would be expected.

With two bulk intake points the distributor could either arrange to have unrestricted access to QOS monitoring information from the bulk supplier, or preferably install its own monitoring device. Hence two additional type C instruments would be required.
Annex E
(informative)

Apportioning techniques

E.1 Introduction

Historically, each utility has applied its own methods of apportioning harmonic limits. In the USA, most of these have been based on IEEE 519. The recent introduction of apportioning guidelines in IEC 61000-3-6 (harmonics) and IEC 61000-3-7 (flicker), has resulted in several European utilities adopting these. (Eskom standards were based on earlier versions of the IEC recommendations.) This annex summarizes the approaches adopted by IEC and IEEE. More detail can be found in the relevant standards. An apportioning methodology that is based on the IEC apportioning procedure and which is used by Eskom, is given in annex F.

E.2 IEC harmonic apportioning

The IEC compatibility levels at the point of common coupling (PCC) are given in table E.1.

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Odd harmonics (non-multiples of 3)</td>
<td>Odd harmonics (multiples of 3)</td>
<td>Even harmonics</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
</tr>
<tr>
<td>5</td>
<td>6,0</td>
<td>3</td>
<td>5,0</td>
<td>2</td>
<td>2,0</td>
</tr>
<tr>
<td>7</td>
<td>5,0</td>
<td>9</td>
<td>1,5</td>
<td>4</td>
<td>1,0</td>
</tr>
<tr>
<td>11</td>
<td>3,5</td>
<td>15</td>
<td>0,3</td>
<td>6</td>
<td>0,5</td>
</tr>
<tr>
<td>13</td>
<td>3,0</td>
<td>21</td>
<td>0,2</td>
<td>8</td>
<td>0,5</td>
</tr>
<tr>
<td>17</td>
<td>2,0</td>
<td>&gt; 21</td>
<td>0,2</td>
<td>10</td>
<td>0,5</td>
</tr>
<tr>
<td>19</td>
<td>1,5</td>
<td></td>
<td></td>
<td>12</td>
<td>0,2</td>
</tr>
<tr>
<td>23</td>
<td>1,5</td>
<td></td>
<td></td>
<td>&gt; 12</td>
<td>0,2</td>
</tr>
<tr>
<td>25</td>
<td>1,5</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&gt; 25</td>
<td>1,3 + 0,5 x 25/h</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Compatibility level for total harmonic distortion (THD) = 8%.

IEC makes use of a three-stage approach to apportioning.
Annex E
(continued)

Stage 1: Approval without detailed evaluation of emission characteristics of the load, or of the supply network response.

The stage 1 criteria are shown below. The assumption is that loads which are small in relation to the short-circuit capacity of the network are not likely to introduce harmonic problems when connected.

\[
\frac{S_I}{S_{SC}} < 0.1\% \text{ (LV)}
\]

\[
\frac{S_{Di}}{S_{SC}} < 0.1\% \text{ to } 0.4\% \text{ (MV)}
\]

where

\( S_{SC} \) is the network short circuit power at the PCC;

\( S_I \) is the agreed power of the customer;

\( S_{Di} \) is the distorting power of the customer.

Stage 2: Approval with detailed evaluation of emission characteristics of the load and the supply network response.

The stage 2 criterion requires that the utility plan harmonic levels be within those specified for MV, HV and EHV in IEC 61000-3-6 (given in tables E.2 and E.3).

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td>Odd harmonics (non-multiples of 3)</td>
<td>Odd harmonics (multiples of 3)</td>
<td>Even harmonics</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
</tr>
<tr>
<td>5</td>
<td>5,0</td>
<td>3</td>
<td>4,0</td>
<td>2</td>
<td>1,6</td>
</tr>
<tr>
<td>7</td>
<td>4,0</td>
<td>9</td>
<td>1,2</td>
<td>4</td>
<td>1,0</td>
</tr>
<tr>
<td>11</td>
<td>3,0</td>
<td>15</td>
<td>0,3</td>
<td>6</td>
<td>0,5</td>
</tr>
<tr>
<td>13</td>
<td>2,5</td>
<td>21</td>
<td>0,2</td>
<td>8</td>
<td>0,4</td>
</tr>
<tr>
<td>17</td>
<td>1,6</td>
<td>&gt; 21</td>
<td>0,2</td>
<td>10</td>
<td>0,4</td>
</tr>
<tr>
<td>19</td>
<td>1,2</td>
<td></td>
<td></td>
<td>12</td>
<td>0,2</td>
</tr>
<tr>
<td>23</td>
<td>1,2</td>
<td></td>
<td></td>
<td>&gt; 12</td>
<td>0,2</td>
</tr>
<tr>
<td>25</td>
<td>0,2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>&gt; 25</td>
<td>0,2 + 0,5 x 25/h</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Planning level for total harmonic distortion at MV = 6,5 %. 
**Annex E**

(continued)

**Table E.3 – IEC planning levels (HV and EHV)**

<table>
<thead>
<tr>
<th></th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
<th>6</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Odd harmonics (non-multiples of 3)</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
<td>Order</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td>5</td>
<td>2,0</td>
<td>3</td>
<td>2,0</td>
<td>2</td>
<td>1,5</td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>2,0</td>
<td>9</td>
<td>1,0</td>
<td>4</td>
<td>1,0</td>
<td></td>
</tr>
<tr>
<td>11</td>
<td>1,5</td>
<td>15</td>
<td>0,3</td>
<td>6</td>
<td>0,5</td>
<td></td>
</tr>
<tr>
<td>13</td>
<td>1,5</td>
<td>21</td>
<td>0,2</td>
<td>8</td>
<td>0,4</td>
<td></td>
</tr>
<tr>
<td>17</td>
<td>1,0</td>
<td>&gt; 21</td>
<td>0,2</td>
<td>10</td>
<td>0,4</td>
<td></td>
</tr>
<tr>
<td>19</td>
<td>1,0</td>
<td></td>
<td></td>
<td>12</td>
<td>0,2</td>
<td></td>
</tr>
<tr>
<td>23</td>
<td>0,7</td>
<td></td>
<td></td>
<td>&gt; 12</td>
<td>0,2</td>
<td></td>
</tr>
<tr>
<td>25</td>
<td>0,7</td>
<td></td>
<td></td>
<td>0,2 + 0,5 x 25/h</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

| **Even harmonics** |        |        |        |        |        |        |
| Order | %      | Order  | %      | Order  | %      |        |
| 5     |        | 2      | 1,5    | 4      | 1,0    |        |
| 7     |        | 9      | 0,3    | 6      | 0,5    |        |
| 11    |        | 15     | 0,2    | 8      | 0,4    |        |
| 13    |        | 21     | 0,2    | 10     | 0,4    |        |
| 17    |        | > 21   | 0,2    | 12     | 0,2    |        |
| 19    |        |        |        | > 12   | 0,2    |        |
| 23    |        |        |        | 0,2 + 0,5 x 25/h |        |        |

Planning level for total harmonic distortion at HV and EHV = 3%.

Using these planning levels, a maximum permissible contribution to the voltage distortion levels by the customer is calculated. The assumption with regard to the summation of various sources of harmonics is shown below.

**Summation law:**

\[
U_{(h)} = \alpha \sqrt[\alpha]{\sum |U_{(h)}|}^{\frac{1}{\alpha}}
\]

<table>
<thead>
<tr>
<th>Harmonic order</th>
<th>α</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 5</td>
<td>1</td>
</tr>
<tr>
<td>5 to 10</td>
<td>1,4</td>
</tr>
<tr>
<td>&gt; 10</td>
<td>2</td>
</tr>
</tbody>
</table>

The apportioned harmonic voltage distortion is given by the equation below (for MV loads).

**Individual customer voltage emission level:**

\[
E_{U(h)_{ci}} = \sqrt[\alpha]{L_{U(h)_{MV}}^{\alpha} - (T \times L_{U(h)_{HV}})^{\alpha}} \times \frac{S}{\sqrt{S_{t}}}
\]

where

- \( E_{U(h)_{ci}} \) is the individual customer maximum emission at the PPC;
- \( T \) is the transformer ratio from HV to MV;
- \( L_{U(h)_{MV}} \) is the utility MV planning level for harmonic voltage \( h \);
- \( L_{U(h)_{HV}} \) is the utility HV planning level for harmonic voltage \( h \);
- \( S_{t} \) is the customer’s maximum demand;
- \( S_{t} \) is the installed capacity.
The maximum current apportioned to the customer is then given by dividing the allocated voltage contribution by the specific network harmonic impedance at the point of common coupling (PCC).

**Stage 3: Exceptional cases**

Stage 3 acceptance of a load is based on considerations such as the presence of other local loads that do not generate harmonics, and the fact that supply capacity might not be taken up for a long time in the future. Subject to these considerations, higher harmonic levels can be allowed.

### E.3 IEEE harmonic apportioning

The harmonic distortion limits at the point of common coupling in IEEE-519 are given in table E.4.

**Table E.4 – IEEE voltage distortion levels**

<table>
<thead>
<tr>
<th>Bus voltage at PCC (kV)</th>
<th>Individual voltage distortion (%)</th>
<th>Total harmonic distortion (THD) (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>≤ 69</td>
<td>3.0</td>
<td>5.0</td>
</tr>
<tr>
<td>&gt; 69 ≤ 161</td>
<td>1.5</td>
<td>2.5</td>
</tr>
<tr>
<td>&gt; 161</td>
<td>1.0</td>
<td>1.5</td>
</tr>
</tbody>
</table>

For periods shorter than 1 h the limits in table E.4 may be exceeded by up to 50 %.

The IEEE standard specifies maximum current injection levels for loads connected to the various voltage levels. These are given in table E.5.

**Table E.5 – IEEE current distortion limits (120 V to 69 kV)**

<table>
<thead>
<tr>
<th>$I_{SC}/I_L$</th>
<th>&lt; 11</th>
<th>11 to &lt; 17</th>
<th>17 to &lt; 23</th>
<th>23 to &lt; 35</th>
<th>&gt; 35</th>
<th>TDD</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 20</td>
<td>4.0</td>
<td>2.0</td>
<td>1.5</td>
<td>0.6</td>
<td>0.3</td>
<td>5.0</td>
</tr>
<tr>
<td>20 &lt; 50</td>
<td>7.0</td>
<td>3.5</td>
<td>2.5</td>
<td>1.0</td>
<td>0.5</td>
<td>8.0</td>
</tr>
<tr>
<td>50 &lt; 100</td>
<td>10.0</td>
<td>4.5</td>
<td>4.0</td>
<td>1.5</td>
<td>0.7</td>
<td>12.0</td>
</tr>
<tr>
<td>100 &lt; 1000</td>
<td>12.0</td>
<td>5.5</td>
<td>5.0</td>
<td>2.0</td>
<td>1.0</td>
<td>15.0</td>
</tr>
<tr>
<td>&gt; 1000</td>
<td>15.0</td>
<td>7.0</td>
<td>6.0</td>
<td>2.5</td>
<td>1.4</td>
<td>20.0</td>
</tr>
</tbody>
</table>

where

- $I_{SC}$ is the maximum short circuit current at PCC;
- $I_L$ is the maximum demand (MD) load current at PCC (averaged MD over 12 months).
Table E.6 – IEEE current distortion limits (> 69 kV to 161 kV)

<table>
<thead>
<tr>
<th>$I_{sc}/I_{L}$</th>
<th>&lt; 11</th>
<th>11 to &lt; 17</th>
<th>17 to &lt; 23</th>
<th>23 to &lt; 35</th>
<th>&gt; 35</th>
<th>TDD</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 20</td>
<td>2.0</td>
<td>1.0</td>
<td>0.75</td>
<td>0.3</td>
<td>0.15</td>
<td>2.5</td>
</tr>
<tr>
<td>20 – &lt; 50</td>
<td>3.5</td>
<td>1.75</td>
<td>1.25</td>
<td>0.5</td>
<td>0.25</td>
<td>4.0</td>
</tr>
<tr>
<td>50 – &lt; 100</td>
<td>5.0</td>
<td>2.25</td>
<td>2.0</td>
<td>0.75</td>
<td>0.35</td>
<td>6.0</td>
</tr>
<tr>
<td>100 – &lt; 1000</td>
<td>6.0</td>
<td>2.75</td>
<td>2.5</td>
<td>1.0</td>
<td>0.5</td>
<td>7.5</td>
</tr>
<tr>
<td>&gt; 1000</td>
<td>7.5</td>
<td>3.5</td>
<td>3.0</td>
<td>1.25</td>
<td>0.7</td>
<td>10.0</td>
</tr>
</tbody>
</table>

where

$I_{sc}$ is the maximum short circuit current at PCC;

$I_{L}$ is the maximum demand (MD) load current at PCC (averaged MD over 12 months).

Table E.7 – IEEE current distortion limits (> 161 kV)

<table>
<thead>
<tr>
<th>$I_{sc}/I_{L}$</th>
<th>&lt; 11</th>
<th>11 to &lt; 17</th>
<th>17 to &lt; 23</th>
<th>23 to &lt; 35</th>
<th>&gt; 35</th>
<th>TDD</th>
</tr>
</thead>
<tbody>
<tr>
<td>&lt; 50</td>
<td>2.0</td>
<td>1.0</td>
<td>0.75</td>
<td>0.3</td>
<td>0.15</td>
<td>2.5</td>
</tr>
<tr>
<td>&gt; 50</td>
<td>3.0</td>
<td>1.5</td>
<td>1.15</td>
<td>0.45</td>
<td>0.22</td>
<td>3.75</td>
</tr>
</tbody>
</table>

where

$I_{sc}$ is the maximum short circuit current at PCC;

$I_{L}$ is the maximum demand (MD) load current at PCC (averaged MD over 12 months).

All load sizes are catered for by the above tables, and therefore a staged approach is not adopted.

It should be noted that the tables have been calculated assuming a linear network impedance (i.e. resonance conditions due to line and cable capacitances, or shunt capacitors are not taken into consideration).
Annex E
(concluded)

E.4 Common features and differences

The common features and differences between the IEC and the IEEE standards are summarized below.

E.4.1 Common features

The common features are:

a) point of common coupling;

b) current emission levels;

c) worst case normal operating network impedance (IEEE = 1 h); and

d) compatibility cannot be guaranteed.

E.4.2 Differences

The differences are:

a) harmonic percentage levels;

b) IEC planning levels;

c) IEC staged approach;

d) IEEE linear impedance vs IEC actual impedance;

e) IEC actual upstream distortion; and

f) IEC installed capacity vs IEEE short circuit ratio.
A methodology for assessing contractual emission levels based on the IEC apportioning procedures

F.1 Overview

Not all loads are large enough to have a significant impact on the voltage distortion levels. For this reason a staged approach is used to differentiate the complexity of the studies to be undertaken when calculating emission levels. This staged approach and the contractual implications are described in this annex.

The criteria used to determine which stage categorization (stage 1, stage 2 or stage 3) a customer qualifies for are set out in table F.1.

<table>
<thead>
<tr>
<th>Stage</th>
<th>PCC voltage</th>
<th>Load maximum demand</th>
<th>Load maximum demand as a percentage of minimum designed operating three-phase PCC fault level</th>
<th>Method of acceptance</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>&lt; 132 kV</td>
<td>&lt; 25 MVA**</td>
<td>&lt; 1 %</td>
<td>Accept</td>
</tr>
<tr>
<td>2</td>
<td>&lt; 132 kV</td>
<td>&lt; 25 MVA**</td>
<td>&gt; 1 %</td>
<td>Apportion</td>
</tr>
<tr>
<td>3</td>
<td>≥ 132 kV</td>
<td>≥ 25 MVA</td>
<td>–</td>
<td>Special analysis</td>
</tr>
</tbody>
</table>

NOTE: Care should be taken where capacitors or underground cables are involved.

The concept of risk allocation also needs to be considered in stage 3. This is illustrated in figure F.1.

Figure F.1 – Risk allocation under stage 3

Figure F.2 indicates the type of contractual clauses that specify the emission levels.

Stage 1: General limits and clauses are included.

Stage 2: Specific contractual emission levels are specified for each parameter. The utility accepts only the risk of the emission levels being correctly calculated.
Stage 3: Specific contractual limits are specified. These may be time-graded or linked to specific network conditions. Two possible stage 3 limits can be developed:

a) technically justifiable limits (i.e. where it can be shown that higher emission levels can be allowed because of specific local network conditions. The risk of exceeding the planning levels shall be shown to be low, and the fair allocation of emission to other customers should not be negatively impacted).

b) concessionary limits (i.e. higher limits which have the risk of exceeding the planning levels in the short or long term). In this case the utility shall stipulate under what conditions the emission levels will be allowed. The customer shall table procedures to reduce emission levels in the event of these conditions occurring. In this case the risk is transferred contractually to the customer.

Figure F.2 – Load emission evaluation procedure

In figure F.2 ‘exceeds’ implies that the customer emissions will exceed those allowed or that the customer defaults to the next stage because of size and voltage connection.

For the contract negotiations with any new customer or evaluation of an existing customer, the above three stages of acceptance should be followed as set out in F.2.1 to F.2.3.

F.2 Acceptance criteria

F.2.1 Acceptance dependent on the network minimum designed operating three-phase fault level – stage 1 assessment

A load connected at a voltage of less than 132 kV and less than 25 MVA in rating, may immediately be connected to a PCC if the maximum designed loading is less than 1 % of the minimum designed operating three-phase PCC fault level.
Annex F

(continued)

The apportioned emission limits for flicker, unbalance and voltage harmonics are given in table F.2.

Table F.2 – Standard apportionment for stage 1 assessment

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quality of supply parameter</td>
<td>Apportionment</td>
</tr>
<tr>
<td>Short term flicker</td>
<td>$P_{st} = 0.35$ minimum</td>
</tr>
<tr>
<td>Voltage unbalance</td>
<td>0.5%</td>
</tr>
<tr>
<td>Voltage total harmonic distortion</td>
<td>1%</td>
</tr>
</tbody>
</table>

The rapid voltage change emission limits are given in table F.3.

Table F.3 – Rapid voltage change emission limits

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
<th>3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Number of changes per hour</td>
<td>$\Delta U_{dyn}/U_n$ (%)</td>
<td>(see note)</td>
</tr>
<tr>
<td>$r$</td>
<td>MV/LV</td>
<td>HV</td>
</tr>
<tr>
<td>$r &lt; 1$</td>
<td>4,00</td>
<td>3,0</td>
</tr>
<tr>
<td>$1 &lt; r \leq 10$</td>
<td>3,00</td>
<td>2,5</td>
</tr>
<tr>
<td>$10 &lt; r \leq 100$</td>
<td>2,00</td>
<td>1,5</td>
</tr>
<tr>
<td>$100 &lt; r \leq 1000$</td>
<td>1,25</td>
<td>1,0</td>
</tr>
</tbody>
</table>

NOTE Where $\Delta U_{syn}$ is as defined in F.3.3.1; and $U_n$ is the actual r.m.s. voltage.

F.2.2 Acceptance as per prescribed proportioning guideline – stage 2 assessment

For loads exceeding 1% of the minimum designed operating three-phase PCC fault level, rated below 25 MVA and connected at a voltage below 132 kV, the different QOS compatibility levels will be apportioned based on the ratio of the load rating and installed capacity under the minimum designed operating three-phase PCC fault level, according to a fixed procedure as given in F.3.

F.2.3 Acceptance per detailed special impact assessment – stage 3 assessment

For large, single, distorting loads such as arc-furnaces, traction, static var compensators, mine winders, etc., or loads connected at a voltage of 132 kV and above or loads larger than 25 MVA in rating, a fixed procedure would not be sufficient to ensure compatibility with the network. Each such installation should be planned and designed individually on a case-by-case basis for both the utility and the customer.

For example, detailed studies are undertaken to investigate the effects of allocating larger flicker emission levels to the customer. Where such larger allocations are made, the contract will specify the conditions under which these higher levels are allowed. Typical conditions that might exist in the contracts include the absence of customer complaints, reduction of emission levels under certain network or generation contingencies, and the availability of existing compensators or filters.

The implication is that the customer needs to balance the cost of achieving the allocated levels, and the risk of the conditions in the contract not being met.
F.3 Apportioning procedure

F.3.1 Harmonics

F.3.1.1 Harmonics – Stage 2 assessment

It is not a simple process to determine what the effect of upstream voltage distortion is at a specific PCC without switching off all the loads at the PCC. A general equation is defined, based on thorough experimental measurements, for the summation of harmonics or reduction of compatibility levels at a specific busbar due to upstream harmonics:

\[
V_{h,pcc(new)} = \left[ V_{h,pcc}^{a} - 0.7 V_{h,us}^{a} \right]^{\frac{1}{a}}
\]  

\( (F1) \)

where

- \( V_{h,pcc(new)} \) is the new percentage voltage planning level of harmonic number \( h \) at the PCC;
- \( V_{h,pcc} \) is the percentage voltage planning level of harmonic number \( h \) at the PCC;
- \( V_{h,us} \) is the percentage upstream harmonic voltage of number \( h \) at the PCC;
- \( a \) is 1 for harmonics 3, 5, 7;
- \( a \) is 1.4 for harmonics 11, 13;
- \( a \) is 2 for harmonics > 13 and other than mentioned above.

This equation therefore gives a method for reducing the set compatibility levels at the PCC due to upstream harmonics. Where upstream harmonics are totally stochastic (i.e. no coincidence) as commonly found in large transmission networks with no direct customers, a value of \( a = 2 \) is typically used in all cases.

Where the upstream levels are so excessive that the PCC limit is reduced by more than 50%, then stage 3 assessment is required.

This available distortion shall now be distributed fairly amongst all new customers to be connected at the PCC. The only applicable parameters known when connecting a new customer or evaluating an existing one at the PCC are the installed capacity at minimum designed operating 3 phase fault level (MVAi) and the customer notified maximum demand (MVAmd). Using these parameters for proportional allocation at the PCC the following equation is used:

\[
V_{h,p} = V_{h,pcc(new)} \times \left[ \frac{MVA_{md}}{MVA_{i}} \right]^{\frac{1}{a}}
\]  

\( (F2) \)

where

- \( V_{h,p} \) is the maximum percentage proportional voltage of harmonic number \( h \) for the new customer;
- \( V_{h,pcc(new)} \) is the percentage voltage planning level of harmonic number \( h \) at the PCC;
- \( a \) is as previously described (see F.3.1.1).
Annex F
(continued)

This equation allows for a fair distribution of allowable harmonic voltage distortion by all connected customers at the PCC. It also makes provision for the connection of future prospective clients, ensuring that the total allowable distortion capabilities of the PCC be used to their full capacity once all customers are connected. The minimum value accepted will be 0.1% even if lower values are calculated.

Where the addition of a new apportioned customer (as above) causes the busbar compatibility level to be exceeded, for instance, due to existing customers connected in the past without sufficient limitations on their allowable pollution levels, the utility will be responsible for ensuring proper network compatibility, taking cognizance of the fact that the supply impedance is highly non-linear under resonance conditions.

To obtain the proportioned harmonic current injection by the specific customer, the following equation can be used assuming a linear supply impedance:

$$I_{h,p} = \frac{V_{h,p}}{X_{sup} \times h}$$  \hspace{1cm} (F3)

where

- $I_{h,p}$ is the allowable apportioned harmonic current injection of the specific customer;
- $h$ is the harmonic number;
- $V_{h,p}$ is the percentage harmonic voltage of number $h$;
- $X_{sup}$ is the 50 Hz minimum designed operating three-phase fault level supply impedance as calculated below:

$$X_{sup} = \frac{V_{line}^2}{MVA_{fl}}$$  \hspace{1cm} (F4)

where

- $V_{line}$ is the PCC line voltage in volts and MVA$_{fl}$ the minimum designed operating three-phase fault level.

This equation therefore allows calculation of the proportional distortion current injection allowed by each customer connected at the PCC, assuming a linear supply impedance. It shall, however, be emphasized that whenever capacitor banks or long underground cables are present on either side of the supply transformer, great care should be taken in applying the above equations, as possible resonant conditions can exist at characteristic harmonic frequencies which would cause the supply impedance to be extremely non-linear at that frequency.

NOTE: The harmonic number at which a capacitor bank is in resonance with the supply (series or parallel) is approximately given by:

$$h \approx \sqrt{\frac{MVA_{sc}}{Mvar_{cap}}}$$  \hspace{1cm} (F5)

with MVA$_{sc}$ being the different network three-phase operating fault levels and Mvar$_{cap}$ the capacitor bank three-phase rating.
If this frequency is close to frequencies of existing harmonics or harmonics of the proposed installation, specialist analysis is required, rather than a simplistic approach. The above equations may, however, be used to give an indication of proportional projection but an in-depth system impact study would be required to ensure proper operation.

Where the specific nature of distorting loads is known, the above proportioning can be relaxed under some circumstances by dividing $I_{h,p}$ by the factor in the table F.4 below. The resulting current can be used in supply contracts.

### Table F.4 – Diversity factors

<table>
<thead>
<tr>
<th>1</th>
<th>2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Type and operating conditions of multiple harmonic generators</td>
<td>Typical diversity factors</td>
</tr>
<tr>
<td>Controlled or uncontrolled converters when a single converter provides 60 % or more of the arithmetic total of the harmonic currents of all the equipment in the installation</td>
<td>1,00</td>
</tr>
<tr>
<td>Uncontrolled converters (rectifiers)</td>
<td>0,90</td>
</tr>
<tr>
<td>Controlled converters operating on co-ordinated duty cycles (fair probability of coincidence)</td>
<td>0,75</td>
</tr>
<tr>
<td>Controlled converters operating independently with unco-ordinated duty cycles (low probability of coincidence)</td>
<td></td>
</tr>
<tr>
<td>(a) ≤ 3 converters</td>
<td>0,60</td>
</tr>
<tr>
<td>(b) ≥ 4 converters</td>
<td>0,50</td>
</tr>
<tr>
<td>A single arc-furnace providing more than 60 % of the arithmetic total harmonic current of the installation</td>
<td>1,00</td>
</tr>
<tr>
<td>Multiple arc-furnaces each providing less than 60 % of the arithmetic total harmonic current of the installation</td>
<td>0,75</td>
</tr>
</tbody>
</table>

### F.3.1.2 Harmonics – Stage 3 assessment

In the case where

a) the customer supply voltage is greater than 132 kV and equal to 132 kV, or  
b) the size of the customer load is bigger than 25 MVA, or  
c) long cables or capacitor banks are absent from either side of the supply transformer,  
a linear supply impedance can no longer be assumed.

From the actual system impedance that is obtained by system simulation studies, the current injection levels are calculated by:

$$I_{h,p} = \frac{V_{h,p}}{X_h}$$  \hspace{1cm} (F6)

where

- $I_{h,p}$ is the allowable apportioned harmonic current of number $h$ at the PCC (in amperes);  
- $V_{h,p}$ is the percentage harmonic voltage emission of number $h$ at the PCC allocated to the new customer (in volts);  
- $X_h$ is the maximum supply impedance of number $h$ at the PCC for any normal operating condition (in ohms).
The maximum supply impedance of number \( h \) at the PCC for any normal operating condition, such as a line out of service, is determined by system simulations at all the applicable harmonic orders. A set of curves is produced for various normal operation conditions. From this set of curves the highest impedance value for each harmonic order is selected.

Figure F.3 shows an example of a network harmonic impedance simulation.

![Figure F.3 – Example of a harmonic impedance plot](image)

**F.3.2 Unbalance**

The emission levels \( B_A \) for a specific customer are calculated using the following equation:

\[
B_A = \sqrt{(UB_{\text{limit}}^2 - UB_{\text{background}}^2) \times \frac{S_{MD}}{S_{\text{installed}}}} \quad (F7)
\]

where

- \( UB_{\text{limit}} \) is the planning limit;
- \( UB_{\text{background}} \) is the existing background unbalance level in the supply network;
- \( S_{MD} \) is the customer notified maximum demand in MVA;
- \( S_{\text{installed}} \) is the installed capacity of the network in MVA.
F.3.3 Flicker

F.3.3.1 Rapid voltage changes

Although no minimum standards for limiting rapid voltage changes are given in NRS 048-2, the concept is introduced in this part of NRS 048 because the flicker emission requirements for customers do not sufficiently limit the possible larger changes in voltage magnitude at lower rates of change. In order to introduce limits on large rapid voltage changes emission limits can be introduced at the PCC.

Figure F.4 shows the definition of a rapid voltage change.

![Figure F.4 – Definition of a rapid voltage change](image)

NOTE A decrease in voltage is illustrated. The voltage could also increase as a result of a rapid voltage change.

where

\[ \Delta U_c \] is the steady state r.m.s. voltage change;

\[ \Delta U_{\text{dyn}} \] is the dynamic r.m.s. voltage change.

The r.m.s. voltages are calculated using a 20 ms window and sliding this 20 ms window at 10 ms intervals.

The emission limits for rapid voltage changes are given in table F.3.

Flicker is typically caused by a.c. arc-furnaces or welding equipment that are remotely connected, i.e. one arc-furnace customer per specific PCC.

For a.c. arc-furnace operation, \( P_{st} \) is linear with respect to the magnitude of the voltage depressions giving rise to it.

The summation of flicker from independent sources is as follows:

\[
P_{st,\text{tot}} = \left( P_{st,\text{background}}^3 + P_{st,\text{new}}^3 \right)^{\frac{1}{3}}
\]

where

\( P_{st,\text{background}} \) is the existing flicker at the PCC;

\( P_{st,\text{new}} \) is the new furnace predicted flicker.
Where existing remotely connected customers are in dispute over their proportional contributions at a specific PCC, the following equation can be used to determine the contribution using fault levels at the respective PCCs, for example, the effect of a furnace at B on the PCC where furnace A is connected, as shown in figure F.5.

\[
P_{st_{cont}} = P_{st_B} \times \left[ \frac{F_{I_{B from A}}}{F_{L_A} - F_{I_{A from B}}} \right]
\]  

(F9)

where

- \( P_{st_{cont}} \) is the contribution of furnace B at A;
- \( P_{st_B} \) is the effect of furnace B acting alone at PCC B;
- \( P_{st_A} \) is the effect of furnace A acting alone at PCC A;
- \( F_{I_{B from A}} \) is the three-phase fault level infeed at B from A;
- \( F_{L_A} \) is the three-phase fault level at A;
- \( F_{I_{A from B}} \) is the three-phase fault level infeed at A from B.

This equation will provide the apportioned flicker (\( P_{st} \)) contribution of furnace B at PCC A. \( P_{st_A} \) and \( P_{st_{cont}} \) can then be summated as given in equation F8 to determine the total PCC \( P_{st} \).
Annex F
(continued)

F.3.3.2 Flicker – Stage 2 assessment

The emission levels $P_{stA}$ for a specific customer are calculated using the following equation:

$$P_{stA} = \frac{3}{V} P_{stlimit}^3 - P_{stbackground}^3 \times \frac{3}{S_{MDA}}$$

where

- $P_{stA}$ is the effect of furnace A acting alone at PCC A;
- $P_{stlimit}$ is the planning limit;
- $P_{stbackground}$ is the existing background flicker level in the supply network;
- $S_{MDA}$ is the customer notified maximum demand in MVA;
- $S_{installed}$ is the installed capacity of the network in MVA.

The minimum short-term flicker level apportioned to any individual MV or HV customer is $P_{st95}$ (daily) = 0.35.

F.3.3.3 Flicker – Stage 3 assessment

F.3.3.3.1 The following technically justifiable considerations exist:

a) for EHV and HV networks where it can be shown that the HV/LV attenuation ratio $R_{LV/HV} = \frac{P_{stLV}}{P_{stHV}}$ is smaller than 1.0, the HV planning level can be increased to

$$P_{stlimit} = \frac{0.8}{R_{LV/HV}}$$

with a maximum planning level of 1.0; and

where

- $R_{LV/HV}$ is the HV/LV attenuation ratio;
- $P_{stLV}$ is the short term flicker level on the LV network;
- $P_{stHV}$ is the short term flicker level on the HV network;
- $P_{stlimit}$ is the maximum value for the HV planning level for short term flicker.

b) where a customer contributes directly to the cost of increasing the fault level of the network, for example, by the installation of a new line which is only built for the purpose of reducing flicker levels and increasing supply reliability. In this case the installed capacity does not change in equation F10. The flicker emission level stays the same, but is related to a higher fault level. If the utility in future uses this line for further load growth, the additional loads might not substantially contribute to the flicker levels. In this case the customer has already paid for the right to the flicker capacity.
Annex F
(concluded)

F.3.3.3.2 The following concessionary considerations exist:

a) where a large customer (B) with low flicker emission levels exists at the PCC (and the probability of this customer becoming a flicker-producer is low), the flicker allocation of the customer can be distributed across the other customers on a basis of:

\[
P_{stA} = \sqrt{P_{stlimit}^3 - P_{stbackground}^3} \times \left( \frac{S_{MDA} + S_{MDB}}{S_{installed}} \right)
\]  \hspace{1cm} (F11)

where

- \( P_{stA} \) is the short term flicker allocation for customer A;
- \( P_{stlimit} \) is the short term flicker planning limit;
- \( P_{stbackground} \) is the background short term flicker level in the supply network;
- \( S_{MDA} \) is the notified maximum demand of customer A in MVA;
- \( S_{MDB} \) is the notified maximum demand of customer B in MVA;
- \( S_{installed} \) is the installed capacity of the network in MVA.

b) where it can be shown that the attenuation ratio \( R_{LVHV} = \frac{P_{stLV}}{P_{stHV}} \) is smaller than 0.8, a higher planning level than 1.0 may be considered. The risk of new MV and LV networks being established with higher attenuation ratios shall be transferred to the customer;

c) where a known long-term risk exists of a power station being closed, the customer may be allowed emission levels based on the higher fault levels with the power station in operation. The risk of the closure of the station shall be transferred to the customer; and

d) at the initial stage of furnace commissioning, problems might be experienced with the furnace or the SVC compensator, or the type of product that initially needs to be processed results in higher flicker emission levels than later “normal” operation. Where network conditions allow, the customer may be allocated higher flicker levels for a specific period of time, for example, 6 months after start-up.