The South African Grid Code

The Network Code

Version 9.0

This document is approved by the National Energy Regulator of South Africa (NERSA)

Issued by:

RSA Grid Code Secretariat
Contact: Mr. Bernard Magoro
Eskom Transmission Division, System Operator
P.O Box 103, Germiston 1400
Tell: +27 (0)11 871 2774
Fax: +27 (0)86 663 8418
Email: magorotb@eskom.co.za

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1. Introduction

(1) This code contains connection conditions for *generators*, *distributors* and end-use *customer*s, and the standards used to plan and develop the *Transmission System (TS).*

2. Applications for *transmission* connections

(1) A *customer* seeking connection to the *TS* or modifications to existing *TS* connections shall apply in writing to the *NTC* to the address specified in the Preamble. The *customer* shall provide all the relevant information requirements specified in the Information Exchange Code at time of application.

(2) The *NTC* shall provide quotes or cost estimates for new connections (or for upgrading existing connections) according to the approved tariff methodology as per the *Tariff Code* and within the following time frames (specified in working days):

		Project Cost	
		<R35million	**>R35million**
Quote Type	**Indicative Cost Estimate**	≤40	≤40
	Budget Quote	≤80	Negotiable
	Network Service (Budget Quote)	≤20	≤20

(3) *Customers* may request provisional quote information from the *NTC*, which shall be provided without commitment and without detailed studies.

(4) The time periods for contracting and for connecting/upgrading *customer* connections shall be negotiated and agreed upon upfront, between the relevant *TNSP* and the *customer* in every instance. Where the *NTC* determines that the *customer* is required to connect to the assets of an independent *TNSP*, the *NTC* shall come to an agreement with the relevant *TNSP* to provide the network connection service to the *customer*.

(5) The *NTC* shall use the standard application form attached as Appendix 3, for the processing of applications, which should be read in conjunction with the information provision requirements as specified in the Information Exchange Code.

(6) Where there is system development or where the provision of access to one *customer* will have a major cost impact on other *customers*, the *NTC* shall notify the affected parties well in advance. If a dispute arises regarding the funding of these expenses, the matter shall be referred and refer the matter to the *NERSA* for a decision. The *NERSA* shall decide on time frames as part of this decision-making process in consultation with the affected *participants*.

3. Connection conditions

(1) This section specifies the minimum technical and design requirements that *customers* shall adhere to when connected to or seeking connection to the *TS*, or for embedded *generators* or co-*generator*s.

3.1 *Generator* connection conditions

(1) This section defines minimum requirements for *units* of the *participants* that are connected to the *TS* and other *generators* defined in the *Governance Code*, section 4, which are required to comply with the *Grid Code*.

(2) Compliance with a *Grid Code requirement (GCR)* shall be applicable to a *unit*/*power station* depending on rated capacity as specified in tables 1(a) and (b). Where a *generator* is required to comply with a GCR, it shall comply with all the requirements as specified in the relevant section.

(3) The *System Operator* shall evaluate and specify the need for optional *IPS* requirements wherever indicated in tables 1(a) and (b). The *System Operator* shall on request make available the information pertaining to the decision.

Table 1(a) Summary of the requirements applicable to specific ratings of non-hydro *units*

Grid code requirement		*Units* other than hydro (MVA rating)					
		<20	**20 to <100**	**100 to <200**	**200 to <300**	**300 - <800**	**>=800**
GCR1	**Protection**						
	- Backup impedance	Yes	Yes	Yes	Yes	Yes	Yes
	- Loss of field	-	Depends on IPS Requirements	Yes	Yes	Yes	Yes
	- Pole slipping	-	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements
	- Trip to house load	-	-	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes
	- Gen trfr backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- HV breaker fail	Yes	Yes	Yes	Yes	Yes	Yes
	- HV breaker pole disagreement	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements
	- *Unit* Switch-onto-standstill protection	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes	Yes	Yes
	- Main protection only	Yes	Yes	Depends on IPS requirements	-	-	-
	- Main protection with monitoring system or main and backup	-	-	Depends on IPS Requirements	Depends on IPS Requirements	-	-
	- Main and backup protection with monitoring system	-	-	-		Depends on IPS Requirements	Yes
	- Reverse power	Depends on IPS Requirements	Yes	Yes	Yes	Yes	Yes
GCR2	Ability to island	-	-	Depends on IPS Requirements	Yes	Yes	Yes
GCR3	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power system stabiliser	Yes	Yes	Yes	Yes	Yes	Yes
	- Limiters	-	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR4	Reactive capabilities	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR5	*Multiple unit tripping*	If the total station output is greater than the single largest contingency as defined for instantaneous reserve					
GCR6	Governing	Depends on IPS Requirements	Yes	Yes	Yes	Yes	Yes
GCR7	Restart after station blackout	-	Depends on IPS Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 unit at station
GCR8	Black starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR9	External supply disturbance withstand capacity	Depends on IPS Requirements	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	**Deleted [2005/08]**						
GCR11	Emergency *unit* capabilities	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR12	Independent action for control in system island	-	-	Depends on IPS Requirements	Yes	Yes	Yes

Table 1(b) Summary of the requirements applicable to specific ratings of hydro *units*

***Grid code* requirement**		Hydro *units* (MVA rating)					
		<20	20 to <100	100 to <200	200 to <300	300 - <800	>=800
GCR1	**Protection**						
	- Backup impedance	]	Yes	Yes	Yes	Yes	Yes
	- Loss of field	-	Depends on IPS Requirements	Yes	Yes	Yes	Yes
	- Pole slipping	-	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements
	Trip to house load	-	-	-	-	-	-
	- Gen trfr backup earth fault	Yes	Yes	Yes	Yes	Yes	Yes
	- HV breaker fail	Yes	Yes	Yes	Yes	Yes	Yes
	- HV breaker pole disagreement	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements	Depends on IPS Requirements
	- *Unit* Switch-onto-standstill protection		Depends on IPS Requirements	Yes	Yes	Yes	Yes
	- Main protection only	Yes	Yes	Depends on IPS requirements	-	-	-
	- Main protection with monitoring system or main and backup	-	-	Depends on IPS Requirements	Depends on IPS requirements	-	-
	- Main and backup protection with monitoring system	-	-	-		Depends on IPS requirements	Yes
	- Reverse power	Depends on IPS Requirements	Yes	Yes	Yes	Yes	Yes
GCR2	Ability to island	-	-	-	-	-	-
GCR3	Excitation system requirements	Yes	Yes	Yes	Yes	Yes	Yes
	- Power system stabiliser	Yes	Yes	Yes	Yes	Yes	Yes
	- Limiters	-	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR4	Reactive capabilities	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR5	*Multiple unit tripping*	-	Depends on IPS Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR6	Governing	Depends on IPS Requirements	Yes	Yes	Yes	Yes	Yes
GCR7	Restart after station blackout	-	Depends on IPS Requirements	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR8	Black starting	-	If agreed	If agreed	If agreed	If agreed	If agreed
GCR9	External supply disturbance withstand capacity	Depends on IPS Requirements	If more than 5 *unit* at station	If the total station output is greater than the single largest contingency as defined for instantaneous reserve			If more than 1 *unit* at station
GCR10	**Deleted [2005/08]**						
GCR11	Emergency *unit* capabilities	Depends on IPS Requirements	Depends on IPS Requirements	Yes	Yes	Yes	Yes
GCR12	Independent action for control in system island	-	-	Depends on IPS Requirements	Yes	Yes	Yes

(4) The *TNSP* shall, subject to the signing of the necessary agreements as mentioned in section 2, make available a *point of connection* to any requesting *generator*.

(5) For new *units* >1000 MW special consideration shall be given to the impact of these risks on future *System Operator* costs, e.g. for *ancillary services*. The *System Operator* is to quantify these expected costs to the *NERSA* as an input to the licensing process.

(6) Applicability of each of the following GCR sections shall be as per tables 1(a) and (b).

3.1.1 Protection (GCR1)

(1) A *generator transformer*, *unit transformer*, associated *busbar* ducts and switchgear shall be equipped with well-maintained protection functions, to rapidly disconnect appropriate plant sections should a fault occur within the relevant protection zones that may affect the *TS*.

(2) The following requirements are associated with each of the protection functions mentioned in tables 1(a) and (b):

Backup impedance
An impedance facility with a reach greater than the impedance of the *generator transformer* shall be used. This shall operate for phase faults in the *unit*, in the *HV yard* or in the adjacent *transmission* lines, with a suitable delay for cases when the corresponding main protection fails to operate.

Loss of field
The *generator* shall provide a facility to detect loss of excitation on a *unit* and initiate a *unit* trip. The type of facility to be implemented shall be agreed with the *NTC*.

Pole slipping facility
*Unit*s shall be fitted with a facility protecting against pole slipping that matches the system requirements, where the *System Operator* determines that it is required.

Reverse power
This protection shall operate in the event of a *unit* inadvertently importing power from the *IPS*. The *unit* shall be disconnected from the *IPS.*

Trip to house load
All *units* built after the implementation of the *Grid Code* shall island when required. *Units* built before the implementation of the *Grid Code* that are equipped with an HP bypass facility shall island when required and must have this protection function installed.This protection shall operate in the event of a complete loss of connectivity, e.g. if all the feeder breakers open at a *power station*. Power flow into the system is cut off and the *generators* will accelerate. Protection schemes shall be provided to disconnect generating *units* from the *TS busbar* before the inter-unit power swings will trip *units*. The *units* shall island, feeding their own auxiliaries. When system conditions have been restored, the islanded *units* can be resynchronised to the system.

***Generator* transformer HV backup earth fault protection**
This is an *IDMT* facility that shall monitor the current in the *generator* transformer neutral connection. It can detect earth faults in the transformer *HV* side or in the adjacent network. The back-up earth fault facility shall trip the *HV* circuit breaker.

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

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

***Unit* switch onto standstill protection**
This protection shall be installed in the *HV yard substation* or in the *unit* protection panels. If this protection is installed in the *unit* protection panels then the *DC* supply for the protection and that used for the circuit breaker closing circuit shall be the same. This protection safeguards the *generator* against an unintended connection to the *TS* (back energisation) when at standstill, at low speed or when inadequately excited.

(3) In addition, should system conditions dictate, the *System Operator* shall determine other capital protection requirements in consultation with the *generator*. This equipment may be installed at the relevant *power station*, and be maintained by the relevant *generator*.

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

(5) Where *generator breakers* are provided (on the *LV* side), tripping and fault clearing times, including breaker interruption time, shall not exceed 120 ms plus an additional 30 ms for DC offset decay.

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

(7) The *System Operator* shall co-ordinate all protection interfaces between the *generator* and the *TNSP*.

(8) The settings of all the protection tripping functions on the *unit* protection system of a *unit*, relevant to *IPS* performance and as agreed with each *generator* in writing, shall be co-ordinated with the *transmission* protection settings. These settings shall be agreed between the *SO* and each *generator*, and shall be documented and maintained by the *generator*, with the reference copy, which reflects the actual plant status at all time, held by the *SO*. The *generator* shall control all other copies.

(9) A *unit* may be disconnected from the *TS* in response to conditions at the *point of connection* that will result in plant damage. Protection setting documents shall illustrate plant capabilities and the relevant protection operations.

(10) *Participants* shall ensure that competent persons shall carry out testing, commissioning and configuration of protection systems. Prototype and routine testing shall be carried out as defined in Appendix 2 A2.3.1.

(11) *Generators* shall communicate any work on the protection circuits interfacing with *transmission* protection systems (e.g. bus zone) to the *System Operator* before commencing the work. This includes work done during a *unit* outage.

3.1.2 Ability to perform *unit islanding* (GCR2)

(1) *Units* that do not have *black start* or self start capabilities must island when required except if the *unit* was constructed before the implementation of the *Grid Code* and without an *HP* bypass facility designed for *islanding*.

(2) *Unit islanding* shall be contracted as an *ancillary service*. The procedure for testing is given in Appendix 2, A2.3.2.

3.1.3 Excitation system requirements (GCR3)

(1) A *unit* shall have a continuously acting automatic excitation control system (*AVR*). The *AVR* shall provide constant terminal voltage control of the *unit* over the entire operating range of the *unit*. (Note that this does not include the possible influence of a power system stabiliser.) Excitation control systems shall comply with the requirements specified in IEC 60034, IEEE 421 or any other standard agreed to by the *System Operator*.

(2) The excitation system of each *unit* shall normally be operated under the control of a continuously acting *AVR*, which shall be set so as to maintain a constant terminal voltage. The *Generator* may not disable or restrict the operation of the *AVR*, unless the *System Operator* is informed.

(3) The excitation control system shall be equipped with a load angle limiter and flux limiter except for installed *AVR* equipment up to and including analogue electronic technology.

(4) The excitation system shall have a minimum excitation ceiling limit of 1,6 pu rotor current, where 1 p.u. is the rotor current required to operate the *unit* at rated load and at rated power factor as defined in IEC 60034, IEEE421 or any other standard agreed to by the *System Operator*.

(5) The *System Operator* shall determine the settings of the excitation system in consultation with each *generator*. These settings shall be documented, with the controlled copy held by the *System Operator*. The *generators* shall control all other copies. The procedure for this is shown in Appendix 2, A2.3.3.

(6) The *unit* shall be able to operate anywhere within its *effective capability diagram* supplied as part of the *Information Exchange Code* section 3. Test procedures are shown in Appendix 2, A2.3.3.

(7) *Units* shall be capable of delivering constant active power output under steady state conditions for voltage changes in the normal operating range (specified in the system operations code).

(8) All *units* built after the implementation of the *Grid Code* shall be equipped with power system stabilisers as defined in IEC 60034, IEEE421 or any other standard agreed to by the *System Operator.* The requirements for other excitation control facilities and *AVR* refurbishment shall be determined in conjunction with the *System Operator*.

(9) *Generators* shall carry out routine and prototype response tests on excitation systems as indicated in Appendix 2, and in accordance with IEC60034-16-3.

3.1.4 Reactive capabilities (GCR4)

(1) *Units* build after the implementation of the *Grid Code* shall be designed to supply rated power output (*MW*) for power factors ranging between 0.85 lagging and 0.95 leading or otherwise as agreed with the *System Operator* in the use-of-system agreement. Power factor readings refer to the *HV* side of the *unit step-up transformer*.

(2) Gas turbine *units* build after the *Grid Code implementation* shall be capable of SCO (synchronous condenser operation), unless otherwise agreed with the *System Operator* and approved by *NERSA*.

(3) Reactive output shall be fully variable between these limits under *AVR*, manual or other control.

(4) *Generators* shall carry out routine and prototype response tests to demonstrate reactive capabilities as indicated in Appendix 2, A2.3.4.

3.1.5 *Multiple unit tripping (MUT) risks* (GCR5)

(1) A *power station* and its *units* shall be designed, maintained and operated to minimise the risk of more than one *unit* being tripped from one common cause within the time window and load limits described below. Two categories of multiple *units* tripping are used to categorise the impact on the *IPS.*

- **Category 1:** Unplanned disconnection or tripping of more than one *unit* instantaneously or within a one hour window, where the total *maximum continuous rating* (*MCR)* of those *units* exceeds the largest credible multiple contingencies.
- **Category 2:** Unplanned disconnection or tripping more than one *unit* instantaneously or within ten minutes, where the total *MCR* of those *units* exceeds the largest single contingency.

(2) The *power station* shall be designed such that no *MUT* category 1 trip risk can occur and a *MUT category 2* trip will not occur more than once in ten years.

(3) The *power station* shall calculate the minimum number of *units* required to trip for each category and identify potential common elements in the *power station* that can cause an *MUT* category 1 or 2 trip. The *power station* shall inform the *System Operator* of these causes with corrective actions planned.

(4) Should the *System Operator* determine that a *power station* presents an unacceptable *MUT* risk for the network, the relevant *generator* and the *System Operator* shall agree on the corrective action required to reduce the *MUT* risk and time frames within which to comply.

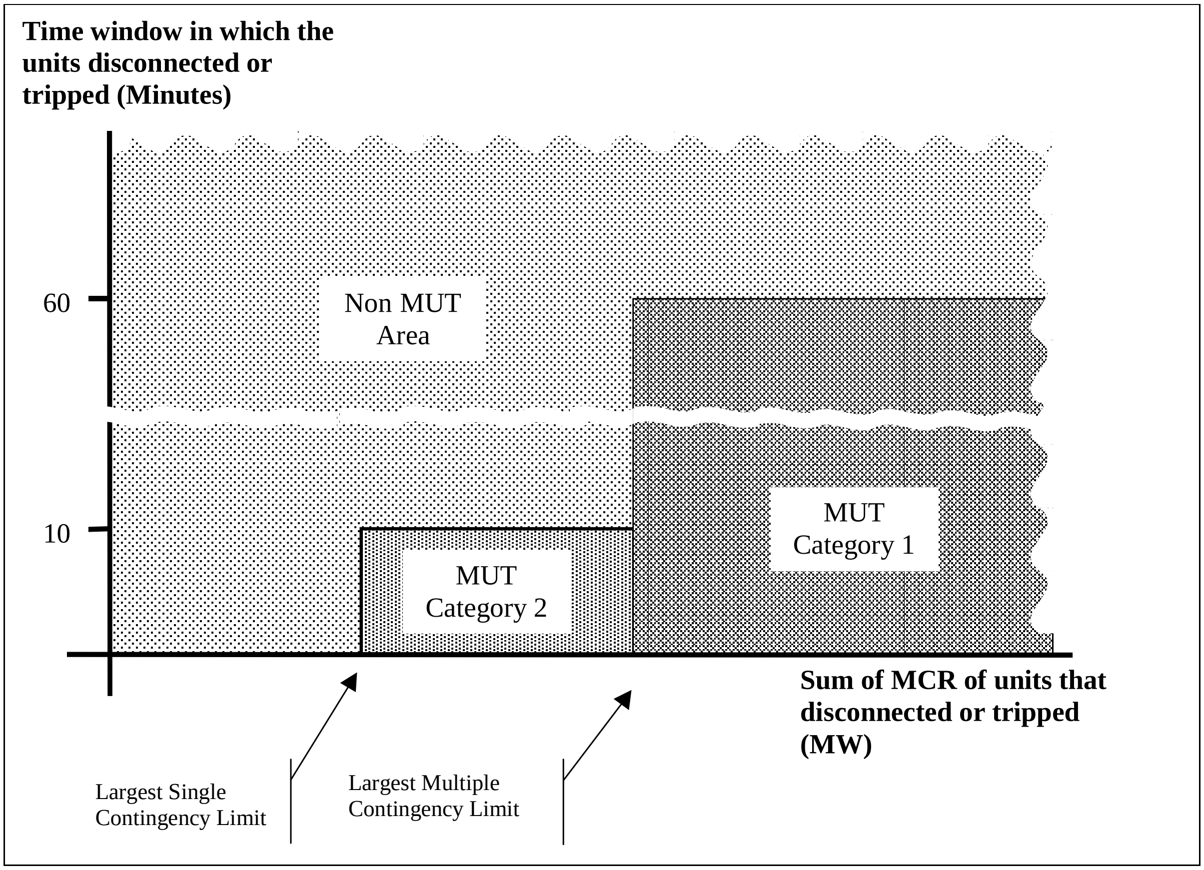

Figure 1: *MUT Zones*

3.1.5.1 System-induced trips

(1) Where a *unit* or *units* is or are disconnected or tripped from the *IPS* owing to sustained system abnormal conditions that exceed the withstand capability of the *unit* as defined and agreed in the *unit* protection setting documentation, such a disconnection or trip shall be considered a *Transmission* induced *MUT*. Such a *MUT* shall be analysed by the *TNSP* with assistance from the *generator*. A full report shall be produced within one month of the event identifying the necessary corrective actions and submitted to the relevant *generator*. Corrective actions with a time frame for implementation shall be agreed upon.

3.1.5.2 Assessing *MUT* trips and corrective action

(1) All category 1 and 2 *MUT* trips shall be analysed by the *generator* and a full report shall be produced within one month of the event to the *NTC*. The *NTC* shall investigate the *MUT* and compile a report in terms of the *System Operation Code*, section 12.

(2) Corrective action shall be implemented by the *participants* in terms of the investigation report of the *System Operator*.

(3) Typical areas of *MUT* are the following:

- Relaying and other equipment powered from a common *DC* supply that is sensitive to disturbances to the supply such as *AC* onto *DC*, which causes the tripping of a *unit* or *units*
- Relaying or other equipment supplied from a common *DC* supply that will malfunction and trip a *unit* or *units* in the event of a loss of *DC* supply
- The loss of *AC* supply for up to two hours to an *uninterruptible power supply (UPS*), leading to the malfunction of the *UPS* or its associated load equipment leading to the trip of a *unit* or *units*
- An earth mat with insufficient capacity or capability to successfully direct lightning or switching surges away from sensitive equipment leading to the trip of a *unit* or *units*
- The use of mercury-type Buchholz facilities that are sensitive to earth tremors leading to the tripping of *units*
- *DC* systems common to generating *units* without proper earth fault location equipment
- Common compressed air plant without proper provision of isolation, storage and non-return valve systems

(4) Routine and prototype response tests shall be carried out to demonstrate *MUT* withstand capabilities as indicated in Appendix 2, A2.3.5.

3.1.6 Governing (GCR6)

3.1.6.1 Design requirements

(1) All *units* above 50 *MVA* shall have an operational governor capable of responding according to the minimum requirements set out in this section.

3.1.6.2 System frequency variations

(1) The nominal *frequency* of the TS is *50 Hz* and is normally controlled within the limits as defined in the *System Operations Code*, section 9. The system frequency could rise or fall in exceptional circumstances and *turbo-alternator units* must be capable of continuous normal operation for the minimum operating range indicated in figure 2 and described in section 3.1.6.

(2) The design of *turbo-alternator units* must enable continuous operation, at up to 100% active power output, within this range.

(3) Tripping times for *units* in the range of 47.5Hz to 48.5Hz shall be as agreed with the *system operator*. Sections 3.1.6.3 to 3.1.6.5 shall be used as guidelines for these tripping times.

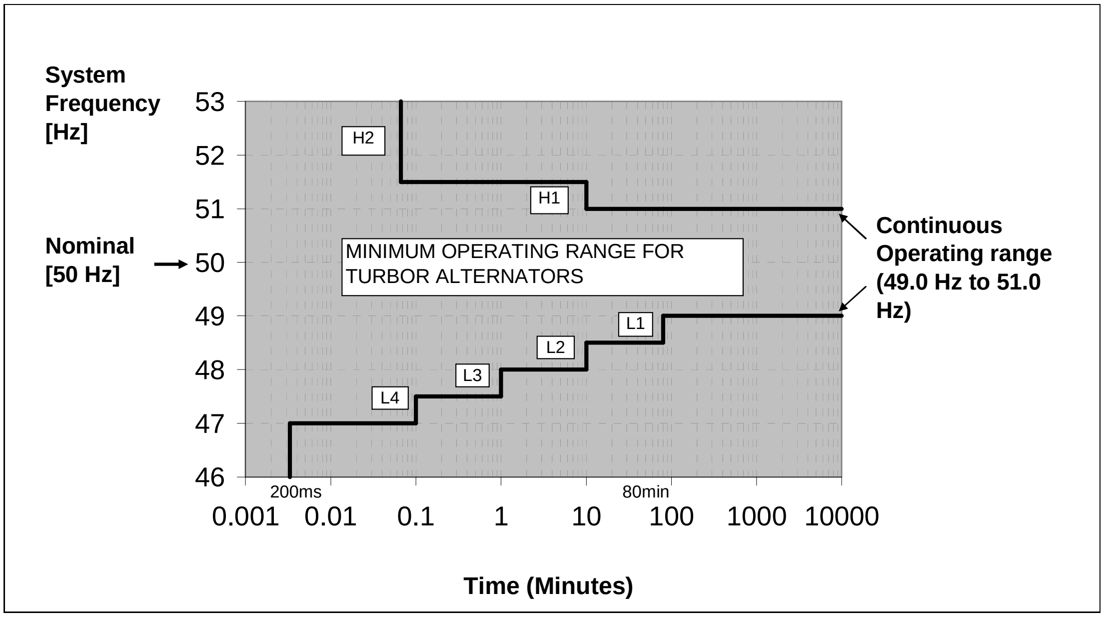

Figure 2: Time vs. system frequency plot, minimum operating range of a *unit*

(4) *Hydro-alternator units* must be capable of continuous normal operation for high *frequency* conditions described in section 3.1.6.4 and low frequency conditions as described in 3.1.6.6.

(5) The *unit* shall remain synchronised for the longest possible time taking into account the *unit's* technical limitations.

3.1.6.3 High frequency requirements for *turbo-alternators*

(1) Synchronised *units* shall respond by automatically reducing active power if the *frequency* is above 50.5 Hz. Governing shall be set to give a 4% *droop* characteristic. The response shall be fully achieved within 10 seconds and shall be sustained for the duration of the frequency excursion. The *unit* shall respond to the full designed minimum operational capability of the *unit* at the time of the occurrence and at least 15% of *MCR*. Those *units* that are contracted for Instantaneous Reserve low frequencies shall provide the capacity for Instantaneous Reserve for high frequencies between the applicable dead-band and 50.5 Hz. These *units* are required to respond at least the same contracted capacity for low frequencies and according to the agreed droop characteristic. The response is required fully within 10 seconds, to an increase in system frequency above the allowable. This response must be sustained for at least 10 minutes (see also figure 3).

(2) **Over-*frequency* conditions in the range 51.0 to 51.5 Hz (Stage H1)**
The *unit* shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes above 51.0 Hz but is less than 51.5 Hz. If the system frequency is greater than 51.0 Hz for 1 minute and the *unit* is still generating power it can be islanded or tripped to protect the *unit*. *Power station*s shall stagger the tripping of the *units* and the philosophy for tripping shall be approved by the *System Operator.*

(3) **Over-f*requency* conditions in the range above 51.5 Hz (Stage H2)**
The *unit* shall be designed to run for at least 1 minute over the life of the plant if the frequency is above 51.5 Hz. If the system *frequency* is greater than 51.5 Hz for 4 seconds and the *unit* is still generating power it can be islanded or tripped to protect the *unit*. *Power stations* shall stagger the tripping of the *units* and the philosophy for tripping shall be approved by the *System Operator.*

3.1.6.4 High *frequency* requirements for *hydro alternators*

(1) The *unit* shall be designed to run for at least 5 seconds over the life of the plant if the *frequenc*y goes above 54 Hz, hence the *hydro-alternator units* must be able to operate for at least 1 second in this range.

(2) If the system *frequency* increases to 54 Hz for longer than 1 second the *unit* can be tripped to protect the *unit*.

3.1.6.5 Low *frequency* requirements for *turbo-alternator units*

(1) *Units* shall be designed to be capable of a minimum response of 3% *of MCR* sent out within 10 seconds of a *frequency* drop over the range from minimum load to 97% *of MCR* sent out, as illustrated in figure 3. The response shall be sustained for at least 10 minutes. All low *frequency* conditions shall be limited to the over fluxing limits specified in the Information Exchange Code, Appendix 3.

(2) Low frequency in the range 49.0 to 48.5 Hz (Stage L1)
The *unit* shall be designed to run for at least 80 minutes over the life of the plant if the *frequency* goes below 49.0 Hz but greater than 48.5 Hz. The *System Operator* shall ensure the *frequency* is less than 80 minutes below 49.0 Hz but greater than 48.5 Hz over a period of 30 years. No automatic tripping of generators shall be allowed in this region.

(3) **Low *frequency* in the range 48.5 to 48.0 Hz (Stage L2)**
The *unit* shall be designed to run for at least 10 minutes over the life of the plant if the frequency goes below 48.5 Hz but greater than 48.0 Hz. The *unit* shall be able to operate for at least 1 minute while the frequency is in this range.

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

(4) **Low *frequency* in the range 48.0 to 47.5 Hz (Stage L3)**
The *unit* shall be designed to run for at least 1 minute over the life of the plant if the *frequency* goes below 48.0 Hz but is greater than 47.5 Hz.

If the system *frequency* is less than 48.0 Hz for 10 seconds the *unit* can be islanded or tripped to protect the *unit*.

(5) **Low *frequency* below 47.5 Hz (Stage L4)**
If the system *frequency* falls below 47.5 Hz for longer than 6 seconds the *unit* can be *islanded* or tripped to protect the *unit*.

(6) Low frequency below 47.0 Hz
If the system *frequency* falls below 47.0 Hz for longer than 200 ms the *unit* can be islanded or tripped to protect the *unit.*

3.1.6.6 Low frequency requirements for *hydro-alternator units*

(1) All reasonable efforts shall be made by the *generator* to avoid tripping of the *hydro-alternator* for under *frequency* conditions provided that the system frequency is above or equal to 46 Hz.

(2) If the system *frequency* falls below 46 Hz for more than 1 second it can be tripped to protect the *unit*.

3.1.6.7 Dead band

(1) The maximum allowable dead band shall be 0.15 Hz for *governing* for *units* contracted for instantaneous reserve and 0.5 Hz for *units* not contracted instantaneous reserve. No response is required from the *unit* while the *frequency* is within the dead band.

(2) *Generators* shall carry out routine and prototype response tests on the governing systems as indicated in Appendix 2, A2.3.6.

(3) Coal-fired *units* not equipped with a dead band facility shall have a droop of 10% or less. At 49.75 Hz a *unit* that does not have a dead band and does not limit the response will respond two and a half times more if the *unit* is on a 4% droop. If the desired response from coal-fired *units* is 5% of MCR sent out at 49,75Hz, then this is equivalent to a 10% droop with no dead band. See figure 3 below. This means the effective requirements from the *units* are the same.

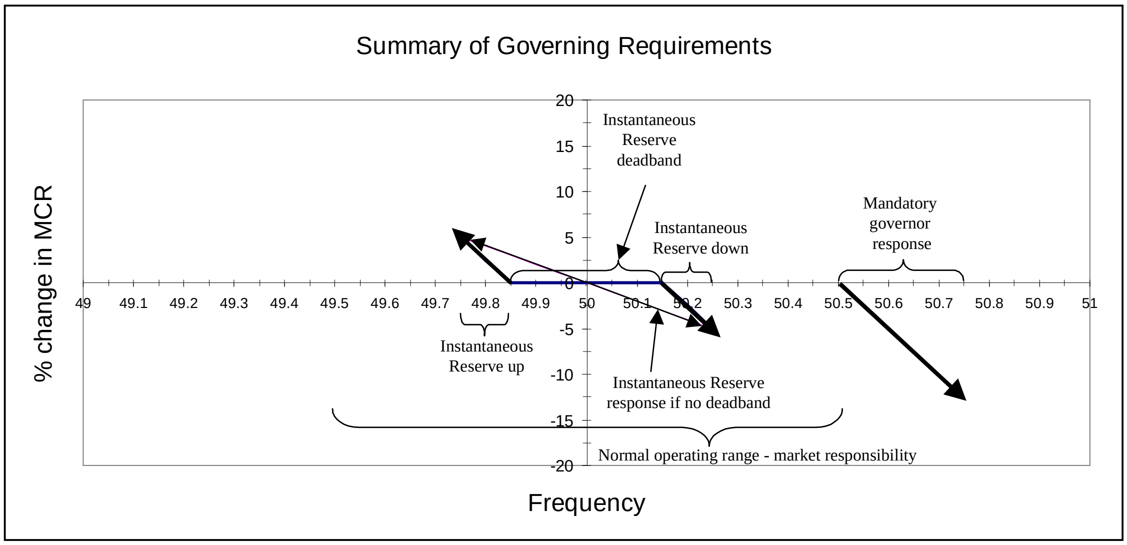

Figure 3: Graphical representation of governing requirements including responsibilities of *customer*s

3.1.6.8 Summary of governor requirements

Refer to section 9 of the *System Operations Code*.

3.1.6.9. Automatic Generation Control requirements

All thermal and hydro units with *MCR* greater than 50MW shall be capable of *AGC*, unless otherwise agreed with the *System Operator.* Refer to section 4 of the *System Operations Code* and the *Information Exchange Code* Appendix 5.

3.1.7 Restart after *power station* black-out (GCR7)

(1) A *unit* shall restart without unreasonable delay following a black-out and restoration of the external auxiliary *AC* supply to the *HV* yard provided that the following is maintained at the *point of connection* for the duration of the *unit* start-up process:

- a stable supply of at least 90% of nominal voltage for *units* with on-load tap changers on the *generator* transformers, and a stable supply of at least 95% nominal voltage for *units* without on-load tap changers on the *generator* transformers
- an unbalance between phase voltages of not more than 3% negative phase sequence
- a *frequency* within the continuous operating range as indicated in figure 2.

Generators shall reasonably co-operate with the *System Operator* in attempting to restart at lower voltage conditions.

(2) For the purposes of this code, examples of unreasonable delay in the restart of a *power station*, where the supply to the *power station* has been restored within 2 hours, are:

- restart of the first *unit* that takes longer than 4 hours after restart initiation
- restart of the second *unit* that takes longer than 2 hours after the synchronising of the first *unit*
- restarting of all other *units* that take longer than 1 hour, one after the other, after the synchronising of the second *unit*.
- delays not inherent in the design of the relevant start-up facilities and which could reasonably be minimised by the relevant *generator*.

(3) *Generators* shall carry out routine and prototype surveys to demonstrate capabilities as indicated in Appendix 2, A2.3.7.

3.1.8 *Black starting* (GCR8)

(1) *Generators* that have declared that they have a station *black start* capability shall demonstrate this facility by test as described in Appendix 2, A2.3.8. The procedure for the tests shall be determined by the *Generators*, in agreement with the *System Operator*.

3.1.9 External supply disturbance withstand capability (GCR9)

(1) Any *unit* or *power station* equipment shall be designed with anticipation of the following voltage conditions at the *point of connection*:

- A voltage deviation in the range of 90% to 110% of nominal voltage
- A 3-phase voltage drop to zero for up to 0.2 seconds, to 75% for 1 second, or to 85% for 60 seconds provided that during the 3 minute period immediately following the end of the 0.2 second, 2 second, or 60 second period the actual voltage remains in the range 90% to 110% of the nominal voltage
- Unbalance between phase voltages of not more than 3% negative phase sequence and/or the magnitude of one phase not lower than 5% than any of the other two for 6 hours
- A Volt/Hz requirement of less than 1.1 p.u.
- A requirement to withstand the following ARC cycle for single-phase faults on the *transmission* lines connected to the *power station:*

  <u>1ph fault</u> - 1ph trip - 1 second 1ph ARC dead time - 1ph ARC - <u>1ph fault</u> - 3ph trip - 3 seconds 3ph ARC dead time - 3ph ARC - 1ph fault - 3ph trip - lock out. This only applies where synchronism is maintained

- A requirement to withstand the following *ARC* cycle for multi-phase faults (phase-to-phase or 3-phase) on the *transmission* lines connected to the *power station*:

  <u>3ph fault</u> - 3ph trip - 3 seconds 3ph *ARC* dead time - 3ph ARC - 3ph fault - 3ph trip - lock out

Routine and prototype response tests shall be carried out to demonstrate capabilities as indicated in Appendix 2, A2.3.9.

3.1.10 Deleted [2005/08] (GCR 10)

3.1.11 Emergency *unit* capabilities (GCR11)

(1) All *generators* shall specify their *units'* capabilities for providing *EL1* support under abnormal power system conditions, as detailed in the *System Operation* Code.

3.1.12 Facility for independent *generator* action (GCR12)

(1) Frequency control under system island conditions shall revert to the *power stations* as the last resort, and *units* and associated plant shall be equipped to handle such situations. The *power stations* shall use reasonable endeavours to control the *frequency* between 49 and 51 Hz.

3.1.13 Automatic under-frequency starting

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

(2) Each gas turbine *unit* shall be equipped with an automatic frequency starting facility with frequency-level settings adjustable between 49Hz and 50Hz. The *System Operator* may enter into an agreement with the gas turbine *generator* to utilise this facility, as and when necessary.

3.1.14 Testing and compliance monitoring

(1) A *generator* shall keep records relating to the compliance by each of its *units* with each section of this code applicable to that *unit*, setting out such information that the *System Operator* reasonably requires for assessing power system performance (including actual *unit* performance during abnormal conditions).

(2) A *generator* shall review, and confirm to the *System Operator*, compliance by the *power station* or each of that *generator's units* with every *GCR* as specified in Appendix 2.

(3) A *generator* shall conduct tests or studies to demonstrate that each *power station* and each generating *unit* complies with each of the requirements of this code. Tests shall be carried out on new *units*, after every outage where the integrity of any *GCR* may have been compromised, to demonstrate the compliance of the *unit* with the relevant *GCR(*s). The *generator* shall continuously monitor its compliance in all material respects with all the connection conditions of the *Grid Code*.

(4) Each *generator* shall submit to the *System Operator* a detailed test procedure, emphasising system impact, for each relevant part of this code prior to every test.

(5) If a *generator* determines, from tests or otherwise, that one of its *units* or *power stations* is not complying in any material respect with one or more sections of this code, then the *generator* shall

- promptly notify the *System Operator* of that fact
- promptly advise the *System* Operator of the remedial steps it proposes to take to ensure that the relevant *unit* or *power station* (as applicable) can comply with this code and the proposed timetable for implementing those steps
- diligently take such remedial action as will ensure that the relevant *unit* or *power station* (as applicable) can comply with this code; the *generator* shall regularly report in writing to the *System Operator* on its progress in implementing the remedial action, and
- after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *System Operator* that the relevant *unit* or *power station* (as applicable) is then complying with this code.

(6) The *System Operator* may issue an instruction requiring a *generator* to carry out a test to demonstrate that the relevant *power station* complies with the *Grid Code requirements*. A *generator* may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.

3.1.15 Non-compliance suspected by the *System Operator*

(1) If at any time the *System Operator* believes that a *unit* or *power station* is not complying with *a GCR*, then the *System Operator* shall notify the relevant *generator* of such non-compliance by issuing a *non-conformance report* (as referred to in the *Governance Code*) specifying the *GCR* concerned and the basis for the *System Operator's* belief.

(2) *The System Operator* shall specify the remedial action required from the *generator* as well as the time frames within which to comply with this code.

(3) Any dispute arising out of such a *non-conformance report* shall be resolved in terms of the dispute resolution procedure described in the *Governance Code*.

3.1.16 *Unit* modifications

(1) If a *generator* proposes to change or modify any of its *units* in a manner that could reasonably be expected to either affect that *unit's* ability to comply with this code, or changes the performance, information supplied, settings, etc., then that *generator* shall submit a proposal notice to the *System Operator* which shall

- contain detailed plans of the proposed change or modification
- state when the *generator* intends to make the proposed change or modification, and
- set out the proposed tests to confirm that the relevant *unit* as changed or modified to operate in the manner contemplated in the proposal, can comply with this code.

(2) If the *System Operator* disagrees on reasonable grounds with the proposal submitted, it shall provide the relevant *generator* with reasons, and the *System Operator* and the relevant *generator* shall promptly meet and discuss the matter in good faith in an endeavour to resolve the disagreement.

(3) The *generator* shall ensure that an agreed change or modification to a *unit* or to a subsystem of a *unit* is implemented in accordance with the relevant proposal agreed to by the *System Operator.*

(4) The *generator* shall notify the *System Operator* promptly after an agreed change or modification to a *unit* has been implemented.

(5) The *generator* shall confirm that a change or modification to any of its *units* as described above conforms to the relevant proposal by conducting the relevant tests, in relation to the connection conditions, promptly after the proposal has been implemented.

(6) A *generator* shall provide the *System Operator* with a report in relation to any compliance test (including test results of that test, where appropriate), within 20 business days after such test has been conducted.

3.1.17 Equipment requirements

(1) Where the *generator* needs to install equipment that connects directly with *TNSP* equipment, e.g. in the high voltage yard of the *TNSP*, such equipment shall adhere to the *TNSP d*esign requirements as set out in this code.

(2) The *TNSP* may require *customers* to provide documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

3.2 Distributors and end-use customers

(1) This section describes connection conditions for *distributors* and *end-use customers.*

(2) The *TNSP* shall, subject to the signing of the necessary agreements as mentioned in section 2, make available a *point of connection* to any requesting *customer*.

3.2.1 Protection

(1) Each *participant* shall take all reasonable steps to protect its own plant.

(2) All plant connected directly to a *TS* substation shall comply with the *Grid Code* protection requirements described in section 5. This shall include busbars supplied directly from *TNSP*

transformers, and lines, transformers and shunt capacitor banks directly connected to that busbar. Further detailed protection applications, insofar as the equipment of one *participant* may have an impact on another, shall be agreed to in writing by the relevant *participants*. *Distributors* that have *customers* connected directly to the *TS substations* are responsible for ensuring that such *customer*s comply with the relevant protection standards.

(3) The *participants* shall co-operate to ensure adequate protection co-ordination.

(4) *Customer's* protection dependability shall not be less than 99% and the *customer* shall ensure that *QOS* standards are adhered to.

3.2.2 Power factor

(1) *Distributors* and *end-use customers* shall take all reasonable steps to ensure that the power factor at the point of supply is at all times 0.9 lagging or higher, unless otherwise agreed to in existing contracts. This requirement applies to each point of supply individually for *customers* with more than one point of supply. A leading power factor shall not be acceptable, unless specifically agreed to in writing with the *System Operator*.

(2) Should the power factor be less than the said limit during any ten demand-integrated half-hours in a single calendar month, the *participants* shall co-operate in determining plans of action to rectify the situation. Overall lowest cost solutions shall be sought and implemented.

3.2.3 Fault levels

(1) The *customer* shall ensure his equipment is capable of operating at the specified *fault levels* as published by the *System Operator*, from time to time.

(2) If *customer* equipment fault level ratings are or will be exceeded, the *customer* shall promptly notify the *NTC*. The *NTC* shall seek overall lowest cost solutions to address fault level problems. Corrective action shall be for the cost of the relevant asset owner and per the implementation plan agreed to.

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

3.2.4 *Distributor* or *end-use customer* network performance

(1) The *participants* shall negotiate in good faith and agree on the details of acceptable levels of performance for *distributor* or *end-use customer* networks. Acceptable network performance principles shall include

- performance comparable with benchmarks for similar networks
- performance within the design or *OEM* specifications of the *customer* and *transmission* equipment
- performance at the *point of connection* that complies with the *TNSP* operating procedures
- performance consistent with the outcomes of the investment criteria as described in section 7.7
- performance that does not negatively impact on agreed levels of performance with other *customers.*

(2) If the *distributo*r or *end-use customer* network performance falls below acceptable levels and affects the quality of supply to other *customer*s or causes damage (direct or indirect) to the *TNSP* equipment, the process for dispute resolution as described in the *Governance Code* shall be followed.

(3) The *NERSA* shall determine criteria for the contracting of acceptable levels of performance.

(4) If *distributors* or *end-use customers* are aware that their network performance could be unacceptable as described above, they shall take reasonable steps at their own cost to overcome

the shortcomings, e.g. by improving their line maintenance practices, improving protection and breaker operating times, if necessary replacing the said equipment, installing additional network breakers, changing operating procedures, installing fault-limiting devices if the number of faults cannot be reduced, etc. These changes to their networks should be effected in consultation with the *TNSP* regarding both the technical scope and the time frame.

(5) Where *QOS* standards are not met, the parties shall co-operate and agree in accordance with *NERSA* power quality directives in determining the root causes and plans of action.

3.2.5 Equipment requirements

(1) Where the *distributor* or end-use *customer* needs to install equipment that connects directly with *TNSP* equipment in *transmission substations*, such equipment shall adhere to the *TNSP* design requirements as set out below in section 4. (These can be at any voltage level.)

(2) The *TNSP* may require *customer*s to provide documentary proof that their connection equipment complies with all relevant design requirements, both by design and by testing.

(3) Any *TNSP*, *distributo*r or *end-use customer* wishing to install a new series capacitor or modify the series reactance of an existing series capacitor shall, at its expense and in accordance with the *NTC's* reasonable requirements, arrange for sub-synchronous resonance, harmonic and protection co-ordination studies to be conducted to ensure that sub-synchronous resonance will not be excited in any *generator*. *SSR* becomes a potential problem if a series capacitor is installed between a generating *unit* and its load or interconnection with the grid. The closer the series compensated line is to the *unit*, the greater the risk because of reduced damping by the resistance of intervening lines and loads.

(4) Any *TNSP*, *distributor* or end-use *customer* wishing to install a new shunt capacitor or modify the shunt capacitance of an existing shunt capacitor shall, at its expense and in accordance with the *NTC's* reasonable requirements, arrange for harmonic resonance studies to be conducted to ensure that harmonic voltage levels do not exceed the limits specified in *NRS048*.

(5) If the studies specified in 3.2.5 (3) or (4) indicate that a risk exists of subsynchronous resonance affecting one or more *units* or harmonic resonance having an impact on the *TS*, the party mandating the studies shall inform the *System Operator* before proceeding with the installation or modifications contemplated.

3.2.6 Additional reinforcement

(1) A *customer* may request additional reinforcements to the *TS* over and above that which could be economically justified as described in section 7. The *TNSP* shall provide such reinforcements if the *customer* agrees to bear the costs, which shall be priced according to the provisions of the *Tariff Code*.

4. *Service provider* design and service level requirements

(1) This section documents the design and other technical standards to which the service providers shall adhere.

(2) The *TNSP* shall offer to connect and, subsequent to the signing of the relevant agreements, make available a *point of connection* to the *TS* to any requesting *distributor or end-use customer*.

4.1 Equipment design standards

(1) Primary *substation* equipment shall comply with relevant IEC specifications. Application shall cater for local conditions, e.g. increased pollution levels, and should be determined by or in consultation with the relevant *customer*. The *TNSP* shall develop and maintain applicable standards for *transmission substation* equipment, details of which shall be supplied to *customers*

upon request. The *TNSP* shall design, install and maintain equipment in accordance with the standards developed.

(2) In the case of equipment operated at *transmission substations* at voltages of 132 kV and below, the relevant *participants* may agree to use standards applicable to the *distributor system*.

(3) The *TNSP* shall ensure that the agreed design standards at the interfaces with *customer* equipment be documented. This documentation shall address the interface for the primary equipment and secondary circuits. Consideration shall also be given to possible common *DC* supplies, *AC* supplies, compressed air systems and fencing.

(4) The *TNSP* shall provide, upon *customers*' request, documentary proof that their connection equipment complies with all relevant standards, both by design and by testing.

(5) The *TNSP* shall ensure that switching devices at or near a *power station* are adequate rated and capable of switching loads and fault currents without generating undue switching surges. Particular attention shall be paid to the correct switching of the generating *unit HV Breaker*. The *TNSP* shall ensure that adequate switching surge protection is provided to the generating *unit* as specified in table 2. Adequate safety margins shall be provided.

4.2 Clearances

(1) Clearances shall comply with at least the requirements of the *Occupational Health and Safety Act*.

4.3 *CT* and *VT* ratios, accuracies and cores

(1) *CT* and *VT* ratios and cores shall be determined by the asset owner in consultation with the other relevant *participants*.

(2) A *TNSP* or a *customer* connected to the *TS* shall ensure that measurement equipment complies with the following accuracy classes for the purposes of operating and control of the *IPS.* Details of equipment, location etc., shall be contained in the operating agreement.

Measurement equipment	**Accuracy class**
Current transformer (CT)	0,2
Voltage transformer (VT)	0,2
Transducer	0,5
Analogue to digital conversion, i.e. *RTU*	0,01

4.4 Standard *busbar* arrangements and *security* criteria

(1) *Substations* on the *TS* shall be configured in accordance with the principles described in this section.

(2) The standard *substation* arrangement shall be based on providing one *busbar* zone for every main transformer/line normally supplying that *busbar*. The *TNSP* shall, however, consider local conditions, type of equipment used, type of load supplied and other factors in the assessment of the required *busbar* redundancy. The *TNSP* shall also adhere to the system reliability criteria as described in section 7.

(3) A *circuit breaker* bypass facility with single *busbar* selection shall be used at 275 kV on single line radial feeds to provide continuity of supply when the line breakers are being maintained.

(4) A double busbar with a circuit breaker bypass facility configuration or a *breaker-and-half configuration* shall be used on all lines above 132kV built after the *Grid Code implementation date*, where justified in accordance with section 7. *HV* busbar configuration at *power stations* will be agreed upon with *generators*.

(5) All *customers* shall be connected via a dedicated and fully equipped bay including circuit breaker, links, earth switches, CTs and VTs (where required), with the capability to link to both busbars, in case of double busbar arrangement. This equipment shall belong to the *TNSP*.

4.5 Motorised isolators

(1) The provision of motorised isolators by the *TNSP* at new *substations* shall be based on the following:

- All 765 kV, 400 kV, 275 kV and 220 kV isolators at new *substations* shall be motorised
- Isolators of 132 kV and below shall be specified on individual merit in consultation with the relevant *customer*

4.6 Earthing and surge protection

(1) The *TNSP* shall ensure adequacy of all earthing installations to provide for

- the safety of personnel and the public
- the correct operation of all protection systems
- agreed design and performance levels.

(2) Earthing isolators shall be provided at new *substations* where the fault level is designed for 20 kA and above.

(3) The *TNSP* shall provide adequate protection to limit lightning surges at the connection point to the limits listed below using the best technology methods. Note that protection has to be placed as close as possible to the *point of connection*. The protection shall be adequate to protect the *generator unit* to the rating levels specified in table 2 below. Adequate safety margins shall be provided.

Table 2 *TNSP* surge protection rating levels requirement

System nominal voltage Un (kV rms)	Lightning impulse voltage at sea level (kV peak)		Switching impulse withstand at sea level (phase-to-neutral) (kV peak)	Switching impulse withstand at sea level (phase-to-phase) (kV peak)	Sixty second power frequency withstand test at sea level (phase-to-neutral) (kV rms)	
	Line terminal	Neutral terminal	Line terminal	Line terminal	Line terminal	Neutral terminal
88	380	250x		450	150	95x
132	550	110+		650	230	38+
220	850	110+		1050	350	38+
275	1050	110+	850	1300	300/260°	38+
330	1300	110+	950	1425	362/314°	38+
400	1425	110+	1050	1530	420/364°	38+
500	1550	110+	1175	1675	525/455°	38+
765	1950	110+	1425	2400	800/693°	38+
Non-uniform insulation			+ Fully graded insulation x Partially graded insulation ° Method II testing to IEC 76-3 (U1/U2)			
Bushing insulation: All bushings shall have insulation levels 10% in excess of transformer's requirement. If transformer ≥5 MVA, the minimum rating for bushings is 33 kV						

4.7 Telecontrol

(1) All *participants* shall be permitted to have telecontrol equipment in the *substations*, yards or buildings of the other *participants*, to perform agreed monitoring and control. The asset owner shall provide access to such equipment.

4.8 Transformer tap change

(1) The *TNSP* shall install automatic tap changing facilities on all new transformers.

(2) Transformers used on the *TS* at 220kV and above are normally not on automatic tap change. Transformers supplying a *customer* are usually on automatic tap change. Voltage levels, sensitivity and time settings and on/off auto tap changing shall be determined by the *System Operator* in consultation with the *customer* and the *TNSP* considering the impact on *customer* investment.

(3) The Volts/Hertz or flux levels (Φ) at the *point of connection* shall meet the following requirements:

Volts/Hertz (pu)	1.1	1.125	1.15	1.175	1.2	1.225	1.25	1.275	1.3
Time (seconds)	continuous	3000	600	180	72	42	30	24	18

4.9 *NTC* obligations towards nuclear *power stations*

(1) The *System Operator* shall provide secure off-site supplies, as requested and specified by the relevant nuclear *generators* and facilities in accordance with the *National Nuclear Regulatory Act* (Act 47 of 1999), to all *TS*-connected nuclear *power stations* and facilities. A written agreement, as per section 2.1.3 of the *System Operation* Code, shall be drawn up and indicators of performance are to be developed and implemented to illustrate the integrity of supply.

4.10 *Substation* drawings

(1) The following set of drawings shall be made available for all points of supply by the respective asset owners, if required by the other party for purposes of connection:

- Station electric diagram
- Key plan
- Bay layout schedules
- Foundation, earth mat and trench layout
- Steelwork marking plan
- *Security* fence layout
- Terrace, road and drainage layout
- Transformer plinth
- General arrangement
- Sections
- Slack span schedule
- Barrier fence layout
- *Security* lighting
- Floodlighting parameter sketch
- Protection details
- Contour plan

(2) All drawings shall use the standard electrical symbol set defined in Appendix 1.

4.11 Recorders

(1) The *TNSP* shall install *QOS* recorders as stipulated by *NRS048* at the points of supply or points of connection, as agreed with the *customers*.

(2) The *TNSP* shall, in consultation with *customers*, install disturbance recorders at locations in the network that shall enable the *System Operator* to adequately analyse system disturbances.

(3) Access to the records shall be as specified in the *Information Exchange Code*, section 5.3.4.

4.12 *HV* yard breaker operating times and synchronisation facilities

(1) Maximum permitted *unit HV breaker* tripping and fault clearance times, including breaker operating times, depend on system conditions and shall be defined by the *NTC*. Guidelines for operating times are:

- 80 ms where the *point of connection* is 400kV or above
- 100 ms where the *point of connection* is 220 kV or 275 kV
- 120 ms where the *point of connection* is 132 kV and below.

(2) All new HV yards at *power stations* shall be equipped with synch-check relays.

4.13 Fault levels

(1) The *TNSP* shall maintain contracted minimum fault levels at each point of supply under normal operating conditions.

(2) The *System Operator* shall calculate maximum fault levels, before and after mitigating actions to reduce fault levels.

(3) The *NTC* shall liase with *customers* as per the process defined in section 7 on how *fault levels* are planned to change and on the best overall solutions when equipment ratings become inadequate. Overall lowest cost solutions shall be sought and a joint impact assessment, covering all aspects, shall be done. Implementation shall be done by the relevant asset owners. The *TNSP* shall communicate the potential impact on the safety of people when equipment ratings are exceeded.

4.14 The *TNSP*'s delivered *QOS*

(1) The *TNSP* shall agree in writing with its *customers*, for every point of supply, on the *QOS* parameters. The *participants* shall negotiate in good faith and agree on the details of acceptable levels of *QOS*. The performance shall

- comply with *NRS048-2 2007* as a minimum
- enable *distributors* to comply with *NRS048-2 2007* standards.

(2) The *participants* shall review the agreed *QOS* performance levels in accordance with the *NERSA* power quality directive, as updated from time to time. If the delivered *QOS* affects the *customer*'s processes or causes damage (direct or indirect) to the *customer's* equipment, the process for dispute resolution as described in the *Governance Code*, section 6, shall be followed

(3) Where the *TNSP* fails to meet the agreed *QOS* parameters due to shortcomings in its own network, it shall take reasonable steps at its own cost to overcome the shortcomings. These changes shall be effected in consultation with the *customer* regarding both the technical scope and the time frame.

5. Service provider protection requirements

(1) This section specifies the minimum protection requirements for *TNSP*s as well as typical settings, to ensure adequate performance of the *TS* as experienced by the *customers*.

(2) *TNSP*'s shall at all times ensure that the protection installations comply with the provisions of this section.

(3) *TNSP's* shall ensure that competent persons shall carry out testing, commissioning and configuration of protection systems. Prototype and routine testing shall be carried out as defined Appendix 2, A2.3.1.

(4) *TNSP'*s shall conduct periodic testing of equipment and systems to ensure and demonstrate that these are performing to the design specifications. Tests procedures shall be according to the manufacturer's specifications or procedures developed by the *NTC.*

(5) *TNSP*'s shall comply with all reasonable requests to make available to *customers* the results of tests performed on equipment.

(6) Protection schemes are divided into

- equipment protection and
- system protection.

5.1 Equipment protection requirements

5.1.1 Feeder protection: 220kV and above

5.1.1.1 Protection design standards

(1) New feeders shall be protected by two equivalent protection systems – Main 1 and Main 2. The Main 1 and Main 2 protection systems shall be fully segregated in secondary circuits.

(2) An additional earth fault function shall be incorporated in the main protection relays or installed separately to alleviate possible deficiencies of distance relays in the detection of high-resistance faults.

5.1.1.2 Protection settings

(1) The protection relays shall provide reliable protection against all possible short-circuits and shall provide remote and/or local backup for *busbar* faults that have not been cleared and shall not be set to provide overload tripping.

(2) Where specifically required, the feeder protection may be set, if possible, to provide remote backup for other faults as agreed upon with other *participants*.

5.1.1.3 Automatic reclosing (ARC)

(1) *Automatic reclosing (ARC)* facilities shall be provided on all feeders.

(2) The *System Operator* shall decide, in consultation with *customers*, *on ARC* selection. This selection shall be based on the real-time behaviour of the system, *generator* impact minimisation, environmental constraints and equipment capabilities. All *ARC* settings and methodology shall be implemented by the *TNSP* and shall be made available to *customers* on request.

ARC cycles
The following *ARC* cycles can be selected for a single-phase fault:

- Double attempt *ARC* cycle for persistent fault:

  <u>1ph fault</u> – 1ph trip – 1ph *ARC* – 3ph trip – 3ph *ARC* – 3ph trip – lockout

- Single attempt *ARC* cycle for persistent fault:

  <u>1ph fault</u> – 1ph trip – 1ph *ARC* – 3ph trip – lockout

  1ph fault – 3ph trip – 3ph *ARC* – 3ph trip – lockout.

The ARC cycle for a multi-phase (mph) fault:

  <u>mph fault</u> – 3ph trip – 3ph *ARC* – 3ph trip – lockout

On some lines the *ARC* shall be switched off according to the following operational needs:

- Sporadically, when a high risk of line fault is recognised, for live line work or to reduce the breaker duty cycle where the condition of breakers is questionable
- Periodically, during a season of high fault frequency
- Permanently, on selected lines with unduly high fault frequency or at the request of *customers*

Single-phase *ARC*
The dead time of single-phase *ARC* shall be selected to one second. The closing of the breaker shall be performed without synchronisation as the synchronism is maintained via the remaining phases that are closed during the whole incident.

Three-phase *ARC*
<u>Fast *ARC*</u>
Fast *ARC*, i.e. fast closing of the breaker without checking synchronism, shall be used only in exceptional circumstances to avoid stress to the rotating machines at the *power stations* and at the *customer*'s plant.

<u>Slow *ARC*</u>
The *dead line charging (DLC)* end is selected in line with table 3 based on *the fault level (FL*) at the connected *substations* A and B.

Table 3 Selection of dead line charging end of the line

End A End B	*Substation FL*<10kA	*Substation FL*>10kA	*Power Station*
Substation FL<10kA	*Substation* with	*Substation* A	*Substation* B

	higher *FL*		
Substation FL>10kA	*Substation* B	*Substation* with lower FL	*Substation* B
Power Station	*Substation* A	*Substation* A	*Power station* with lower *FL*

In most applications the dead time of slow *ARC* is set to three seconds at the *DLC* end of the line. At the synchronising end of the line the *ARC* dead time is usually set to four seconds. The close command will be issued only after synch-check is completed. This may take up to two seconds if synchronising relays are not equipped with direct slip frequency measurement. The breaker may take longer to close if its mechanism is not ready to close after initial operation at the time when the close command is issued.

On the line between two *power stations* the dead time at the *DLC* end should be extended to 25 seconds to allow *units'* rotor oscillations to stabilise. The dead time on the synchronising end is then accordingly extended to 30 seconds

The synchronising relays shall be installed at both ends of the line to enable flexibility in *ARC* cycles and during restoration.

5.1.1.4 Power swing blocking

(1) The *NTC* shall ensure that all unwanted operations of distance relays during power swing conditions are blocked on the *TS*. The *TNSP* shall ensure that all new distance relays on the *TS* shall be equipped with power swing blocking (*PSB*) facilities.

5.1.2 Feeder protection: 132kV and below

5.1.2.1 Design standards

(1) Feeders from 44kV up to and including 132kV

The *network service provider* shall ensure that these *feeders* shall be protected by a single or dual main protection system, incorporating either distance or differential protection. The single main protection system shall have a separate backup protection system for both phase–to-phase and phase-to-earth faults. The criteria used to select between a dual main protection systems versus a single main with back-up will be based on the system and *customer* requirements

(2) Feeders from 1kV to 44kV

The *network service provider* shall ensure that these *feeders* shall be protected by a single protection system, for both phase–to-phase and phase-to-earth faults unless otherwise agreed with the *customer*.

(1) The protection shall be equipped with automatic reclosing. Synchronising relays shall be provided on feeders that operate in "ring supplies" and are equipped with line voltage transformers.

5.1.2.2 Protection settings

(1) Protection relays shall provide reliable protection against all possible short-circuits, shall provide remote and/or local backup for uncleared *busbar* faults and shall not be set to provide overload tripping where measurements and alarms are provided on the *SCADA* system. In isolated applications where the *SCADA* system is not available, overload tripping shall be provided. Where overload conditions are alarmed at control centres, it is the control centre's responsibility to reduce load to an acceptable level as quickly as possible.

5.1.2.3 Automatic reclosing

(1) The *customer* shall determine *ARC* requirements. The *System Operator* may specify additional *ARC* requirements for system *security* reasons, which could extend beyond the *TNSP substations*.

5.1.3 Teleprotection requirements

(1) New distance protection systems shall facilitate instantaneous tripping for faults anywhere on the protected line, either by making use of teleprotection facilities or by using over reaching zones.

5.1.4 Transformer and reactor protection

(1) The standard schemes for transformer protection comprise a number of systems, each designed to provide the requisite degree of protection for the following fault conditions:
Faults within the tank
Faults on transformer connections
Overheating
Faults external to the transformer

(2) The *TNSP* shall consider the application and where necessary implement the following relays in the design of the protection system:

Transformer *IDMT E/F*
The *MV* (transformer secondary voltage) *E/F* protection shall discriminate with the feeder *B/U E/F* protection for feeder faults.

Transformer *HV/MV IDMT O/C*
The *System Operator* requires that the IDMT O/C does not operate for twice transformer full load. Overloading of the transformer is catered for by the winding and oil temperature protection.

Transformer *HV/MV* instantaneous *O/C*
This backup protection is to cater for flash-overs external to the transformer on the *HV* side or *MV* side and should operate for minimum fault conditions (possibly also for an *E/F* condition). However, the overriding requirement is that it shall not operate for through faults or for magnetising inrush current.

Transformer *LV* (tertiary) *IDMT*/instantaneous *O/C*
This protection is to operate for external faults between the main delta winding of the transformer and the auxiliary transformer, but not for faults on the secondary side of the auxiliary transformer. The auxiliary transformer is protected by Buchholz and temperature protection.

Transformer current differential protection
This is the main transformer protection for *E/F* and phase-to-phase faults. Maximum sensitivity is required, while ensuring no incorrect operation for load, for through fault conditions or for magnetising inrush current, with its attendant decaying offset.

Transformer high impedance restricted *E/F*
This protection is an additional protection for the transformer differential relay to cater for earth faults close to the star point of the transformer winding, where phase–to-phase faults are most unlikely to occur.

Transformer thermal overload
Winding temperature and oil temperature relays, supplied by the manufacturer, are used to prevent transformer damage or lifetime reduction owing to excessive loading for the ambient temperature or during failure of the cooling system.

5.1.5 *Busbar* protection

(1) All Transmission substation busbars with voltages above 22kV and all busbars at *power stations' HV* yards shall be equipped with appropriate busbar (Bus Zone) protection systems.

(2) Where more than one *participant* is affected, the design of busbar protection shall be agreed between affected *participants*.

5.1.6 Bus coupler and bus section protection

(1) Bus coupler and bus section panels shall be equipped with *O/C* and *E/F* protection.

5.1.7 Shunt capacitor protection

(1) All the new capacitor banks shall be equipped with sequence switching relays to limit inrush current during capacitor bank energisation. Inrush reactors and damping resistors shall also be employed to limit inrush current.

(2) The following protection functions shall be provided for all types of protection schemes:
- Unbalanced protection with alarm and trip stages
- Over-current protection with instantaneous and definite time elements
- Earth fault protection with instantaneous and definite time-sensitive function
- Overload protection with *IDMT* characteristic
- Over-voltage with definite time
- Circuit breaker close inhibit for 300 seconds after de-energisation
- Ancillary functions as indicated in 5.1.9 below

5.1.8 Over-voltage protection

(1) Primary protection against high transient over-voltages of magnitudes above 140% (e.g. induced by lightning) shall be provided by means of surge arrestors. To curtail dangerous, fast-developing over-voltage conditions that may arise as a result of disturbances, additional over-voltage protection shall be installed on shunt capacitors and feeders.

(2) The *NTC* shall provide suitable over-voltage protection system for shunt capacitor banks.

(3) Over-voltage protection on the feeders is set to trip the local breaker at a voltage level of 120% with a delay of one to two seconds.

5.1.9 Ancillary protection functions

(1) Protection systems are equipped with auxiliary functions and relays that enable adequate co-ordination between protection devices and with bay equipment. The *TNSP* shall consider and implement where appropriate the following functions for all new protection system designs:

Breaker fail/Bus strip
Each individual protection scheme is equipped with a breaker fail/bus strip function to ensure fast fault clearance in the case of circuit breaker failure to interrupt fault current.

Breaker pole discrepancy
Breaker pole discrepancy protection compares, by means of breaker auxiliary contacts, the state (closed or opened) of breaker main contacts on each phase. When the breaker on one phase is in a different position from the breakers on the remaining phases, a trip command is issued after a time delay.

Breaker anti-pumping
To prevent repeated closing of the breaker in the case of a fault in closing circuits, the standard protection schemes provide breaker anti-pumping timers. Circuit breakers are often equipped with their own anti-pumping devices. In such cases anti-pumping function is duplicated.

Pantograph isolator discrepancy
The pantograph isolator discrepancy relay operates in the same manner as breaker pole discrepancy and is used to issue local and remote alarm signals.

Master relay
Transformer and reactor protection schemes are equipped with latching master relay that requires manual resetting before the circuit breaker is enabled to close. The master relay is operated by *unit* protection that indicates the possibility of internal failure. Resetting of the master relay and closing of the circuit breaker are permitted only after inspection of the transformer/reactor and after sanctioning has been obtained from the responsible person.

5.2 System protection requirements

5.2.1 Under-frequency *load shedding*

(1) The actions taken on the power system during an under-frequency condition are set out in section 9 of the *System Operation* Code.

(2) Under-frequency *load shedding* relays shall be installed as determined by the *System Operator* in consultation with the *customers*. Where such equipment is installed in *customer* plant, this shall be done in agreement with the *customer*. The respective *distributor* or *TNSP* shall pay for the installation and maintenance of these relays.

(3) Under-frequency protection schemes comprising analogue or solid state protection relays shall be tested at least once every two years while those comprising numerical protection relays shall be tested at least once every five years. *Distributors* and *end-use customers* shall submit to the *System Operator* a copy of the written report on each such test, within a month of the test being done, in the format specified in section 5.3 of the Information Exchange Code. The testing shall be done by isolating all actual tripping circuits, injecting a frequency to simulate a frequency collapse and checking all related functionality.

5.2.2 Out-of-step tripping

(1) The purpose of the out-of-step tripping protection is to separate the *IPS* in a situation where a loss of synchronous operation takes place between a *unit* or *units* and the main power system. In such a situation system separation is desirable to remedy the situation. Once the islanded system has been stabilised, it can be reconnected to the main system.

(2) The *System Operator* shall determine and specify the out-of step tripping functionality to be installed at selected locations on the *TS* by the *TNSP*.

5.2.3 Under-voltage *load shedding*

(1) Under-voltage *load shedding* protection schemes are used to prevent loss of steady-state stability under conditions of large local shortages of reactive power (voltage collapse). Automatic *load shedding* of suitable loads is carried out to arrest the slide.

(2) The *System Operator* shall determine and specify the under-voltage *load shedding* functionality to be installed at selected locations on the *TS* by the *TNSP*.

5.2.4 *Sub-synchronous resonance* protection

(1) The *sub-synchronous resonance (SSR)* condition may arise on the *IPS* where a *unit* is connected to the *IPS* through long series compensated *transmission* lines. The potential for unstable interaction is related to system topology and is greater where higher degrees of compensation and if larger thermal *units* are employed. The *SSR* condition is addressed through either protection or mitigation. In the case of protection, a suitable relay shall be deployed as part of the *unit* protection that will lead to the *unit* disconnecting on detection of the *SSR* condition. The protection does not reduce or eliminate the torsional vibration, but rather detects it and acts to remove the condition leading to the resonance. Mitigation, on the other hand, acts to reduce or eliminate the resonant condition. Mitigation is needed only where it is desirable or essential to continue operation when the power system is at or near a resonant condition.

(2) New *generators* shall liase with the *NTC* regarding *SSR* protection studies. Least-cost solutions shall be determined by the *NTC* in accordance with section 7 and implemented by the relevant asset owner.

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

5.3 Protection system performance monitoring

(1) To maintain a high level of protection performance and long-term sustainability, the *TNSP* shall monitor protection performance on the *TS*. The *TNSP* shall ensure that the protection performance is adequate at all times.

(2) Each protection operation shall be investigated by the *TNSP* for its correctness based on available information. The *TNSP* shall provide *customers* affected by a protection operation with a report when requested to do so.

6. Nomenclature

(1) All safety terminology shall be determined by the *NTC* in compliance with the Occupational Health and Safety Act.

(2) Engineering drawings relating to connecting equipment shall use the standard *NTC* symbol set and layout conventions as defined in Appendix 1.

7. *TS* planning and development

(1) This section specifies the criteria and procedures to be applied by the *NTC* in the planning and development of the *TS.* It furthermore provides for accountability for *TS* planning and development and sets the required standards and targets. It also specifies the reciprocal obligations and interactions between *participants*.

(2) The *TS* shall be developed in accordance with the prevailing *NERSA* regulatory framework, as being implemented from time to time.

(3) The development of the *TS* may occur for a number of reasons, including but not limited to

- changes to *customer* requirements or networks
- the introduction of a new *transmission substation* or *point of connection* or the modification of an existing connection between a *customer* and the *TS*
- the cumulative effect of a number of developments as referred to above
- the need to reconfigure, decommission or optimise parts of the existing network.

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

7.1 Planning process

(1) The *NTC* shall follow a planning process divided into major activities as follows:

- Identification of the problem
- Formulation of alternative options to meet this need
- Study of these options to ensure compliance with agreed technical limits and justifiable reliability and quality of supply standards
- Costing of these options on the basis of approved procedures
- Determination of the preferred option
- Building of a business case for the preferred option using the approved justification criteria

- Request for approval of the preferred option and initiation of execution.

7.2 Identification of the need for *TS* development

(1) The *NTC* shall source relevant data from the National Integrated Resource Plan, the National Integrated Energy Plan, specific *customer* information, system performance statistics, *TS* load forecast, and government and *customer* development plans to establish the need for network strengthening.

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

(3) The *NTC* shall annually conduct a planning review with parties to co-ordinate *TS* and *distributor* network development needs.

7.3 Forecasting the demand

(1) The *NTC* shall annually produce a *TS* demand forecast for the next ten years by end August of each year.

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

(3) To forecast the maximum demand *(MW)* for each *transmission substation*, the *NTC* shall use *distributor* and end-use *customer* load forecasts.

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

(5) All *distributors* and end-use *customers* (or their retailer) shall supply their ten-year-ahead load forecast data to the *NTC* as detailed in the *Information Exchange Code* annually, by the end of July. All *customers* shall inform the *NTC* of any changes in excess of 50 *MW* to this forecast when this information becomes available.

7.4 *TS* development plan

(1) The *NTC* shall annually publish a minimum five-year-ahead *TS* development plan by end October, indicating the major capital investments planned (but not yet necessarily approved). The plan shall include at least

- the acquisition of servitudes for strategic purposes
- a list of planned investments including costs
- diagrams displaying the planned changes to the *TS*
- an indication of the impact on *customers* in terms of service quality and cost
- any other information as specified by the *NERSA* from time to time.

(2) The *TS* development plan shall be based on all *customer* requests received at that time, as well as *NTC* initiated projects based on load forecasts and changes in generation.

(3) The *NTC* shall engage in a consultative process with *customers* and the *NERSA* on the *TS* development plan. The consultation process shall include

- an annual public forum to disseminate the intended *TS* development plan
- regular interfacing and joint planning with *participants* regarding *TS* development.

(4) Disputes arising from the above process shall be decided in terms of the dispute resolution mechanism in the Governance Code.

(5) The *NTC* shall provide a five-year statement of opportunities to render *ancillary services* for the mitigation of network constraints.

(6) The *NTC* shall also provide other *IPS* development plans as defined in the licence and/or market rules.

7.5 Development investigation reports

(1) Before any development of the network proceeds in terms of section 7.7, the *NTC* shall compile a detailed development investigation report. The report shall be used as the basis for the investment decision and shall as a minimum contain the following elements:

- A description of the problem/request and the objectives to be achieved
- Alternatives considered (including non-transmission or capital) and an evaluation of the long-term costs/benefits of each alternative
- Detailed techno-economic justification of the alternative selected in accordance with the approved investment criteria, with consideration of relevant scenarios and appropriate risk analysis
- Diagrams, sketches and relevant technical study results
- Clear statement and analysis of the assumptions used.

7.6 Technical limits and targets for long-term planning purposes

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

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

7.6.1 Voltage limits and targets

(1) Technical and statutory limits are reflected in table 4.

Table 4 Voltage limits for planning purposes

Nominal continuous operating voltage on any bus for which equipment is designed	U_N
Maximum continuous voltage on any bus for which equipment is designed Note: To ensure voltages never exceed Um, the highest voltage used at sending end *busbar*s in planning studies should not exceed 0.98 Um	U_M
Minimum voltage on *PCC* during motor starting	0.85 U_N
Maximum voltage change when switching, capacitors, reactors, etc. (system healthy)	0.03 U_N (healthy)
Statutory voltage on bus supplying *customer* for any period longer than 10 consecutive minutes (unless otherwise agreed in Supply Agreement)	U_N + OR -5%

Table 5 Standard voltage levels

U_N (kV)	U_M (kV)	$(U_M-U_N)/U_N$ %
765	800	4,58
400	420	5,00
275	300	9,09
220	245	11,36
132	145	9,85
88	100	13,63

66	72,5	9,85
44	48	9,09
33	36	9,09
22	24	9,09
11	12	9,09

(2) Target voltages for planning purposes at Distribution voltages are specified in the Distribution Code, target voltages for planning purposes at *Transmission* voltages are as in Table 6:

Table 6 Target voltages for planning purposes at *Transmission* voltages

Minimum steady state voltage at bus supplying *customer* load unless otherwise specified in the *customer*'s supply agreement	0.95 U_N
Minimum and maximum steady state voltage on any controlled bus, unless otherwise specified in the *customer* supply agreement: system healthy: after designed contingency (before control actions): (after control actions):	 0.95 – 1.05 U_N 0.90 U_N – 0.98 U_M 0.95 – 1.05 U_N
Maximum steady state voltage at bus supplying *customer* load unless otherwise specified in the *customer* supply agreement	1.05 U_N
Maximum harmonic voltage caused by *customer* at *PCC*: Individual harmonic: total (square root of sum of squares):	 0.01 U_N 0.03 U_N
Maximum negative sequence voltage caused by *customer* at *PCC*: Continuous single-phase load connected phase-to-phase: Multiple, continuously varying, single-phase loads:	 0.01 U_N 0.015 U_N
Harmonic voltage limits:	As defined in NRS048
Maximum voltage change owing to load varying N times per hour:	$(4.5 \log_{10} N)\%$ of U_N
Maximum voltage decrease for a 5% *(MW)* load increase at receiving end of system (without adjustment):	0.05 U_N

7.6.2 Other targets for long-term planning purposes

7.6.2.1 *Transmission* lines

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

7.6.2.2 Transformers

(1) Standard transformer ratings shall be determined and updated from time to time using IEC specifications. The permissible overload of a specific transformer depends on load cycle, ambient temperature and other factors. If target loads are exceeded, the specific situation shall be assessed, as it may be possible to defer adding extra transformers.

7.6.2.3 Series capacitors

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

7.6.2.4 Shunt reactive compensation

(1) Shunt capacitors shall be able to operate at 30% above their nominal rated current at Un to allow for harmonics and voltages up to Um.

7.6.2.5 Circuit breakers

(1) The *TNSP* shall specify and install circuit breakers that meet system fault levels and other conditions considered important for the safe and secure operation of the *TS*. Ratings are to be according to international circuit breaker standards such as IEC.

7.6.3 Reliability criteria for long-term planning purposes

(1) The *NTC* shall develop the *TS* on the basis of the justifiable redundancy. With one line or transformer or reactive compensation device out of service (n-1), it shall be possible to supply the entire load under all credible system operating conditions. The (n-1) minimum redundancy requirement shall also apply to transformers installed at transmission substations supplying equipment rated at 66kV or above.

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

(3) An unfirm *transmission* infeed to an underlying distribution network is acceptable, as long as the underlying distribution network can supply the entire load without *load shedding* or load curtailment and without violating the technical planning limits on either the *transmission* or *Distribution systems* on loss of the *transmission* infeed.

(4) A system cannot be made 100% reliable, as planned and forced outages of components will occur and multiple outages are always possible, despite having a very low probability of occurrence.

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

(6) Additional equipment shall be provided if it can be justified to be included in the rate base in terms of the least economic cost and/or cost reduction investment criteria (sections 7.7.1 and 7.7.2) or the cost is recoverable from a *customer* or group of *customers* in accordance with the *Transmission Tariff Code* or section 7.9.

(7) A connection that does not meet n-1 requirement is still acceptable to a dedicated customer, provided that it is specified as such in the customer's connection agreement

7.6.4 Contingency criteria for long-term planning purposes

(1) A system meeting the n-1 (or n-2) contingency criterion must comply with all relevant limits outlined in section 7.6.1 (voltage limits) and the applicable current limits, under all credible system conditions.

(2) For contingencies under various loading conditions it shall be assumed that appropriate, normally used generating plant is in service to meet the load and provide spinning reserve. For the more probable n-1 network contingency, the most unfavourable generation pattern within these limitations shall be assumed, while for the less probable n-2 network contingency an average pattern shall be used. More details of load and generation assumptions for load flow studies are given in section 7.6.5.

(3) The generation assumptions for the n-1 and n-2 network contingencies do not affect the final justification to proceed with investments, but merely define what is meant by the statement that the system has been designed to meet an n-1 or n-2 contingency.

7.6.5 Integration of *power stations*

(1) When the integration of *power stations* is planned, the following network redundancy criteria shall apply:

Power stations **of less than 1 000 MW**

- With all connecting lines in service, it shall be possible to transmit the total output of the *power station* to the system for any system load condition. If the local area depends on the *power station* for voltage support, the connection shall be made with a minimum of two lines.
- Transient stability shall be maintained following a successfully cleared single-phase fault.
- If only a single line is used, it shall have the capability of being switched to alternative *busbars* and be able to go onto bypass at each end of the line.

Power stations **of more than 1 000 MW**

- With one connecting line out of service (n-1), it shall be possible to transmit the total output of the *power station* to the system for any system load condition.
- With the two most onerous line outages (n-2), it shall be possible to transmit the total output of the *power station* less its smallest *unit* to the system.
- Smallest *unit* installed at the *power station* shall only include *units* that are directly connected to the *transmission system* and are centrally dispatched.

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

- A three-phase line or *busbar* fault, cleared in normal protection times, with the system healthy and the most onerous *power station* loading condition; or
- A single-phase fault cleared in "bus strip" times, with the system healthy and the most onerous *power station* loading condition; or
- A single-phase fault, cleared in normal protection times, with any one line out of service and the *power station* loaded to average availability.

(3) The cost of ensuring transient stability shall be carried by the *generato*r if the optimum solution, as determined by the *NTC*, results in *unit* or *power station* equipment being installed. In other cases, the *TNSP* shall bear the costs and recover these as per the approved tariff methodology.

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

(5) The *busbar* layout shall ensure that no more than one *unit* with rated output 500MW or more, or generation totalling not more than the greater of the *largest single contingency limit* or 1 000 MW is lost as a result of a single contingency.

(6) To enable the *NTC* to successfully integrate new *power stations*, detailed information is required per *unit* and *power station*, as described in the Information Exchange Code.

(7) When the integration of a nuclear facility or off-site power supply to a nuclear facility is planned, the levels of redundancy and/or reliability of the *TS* and off-site power supply requirements specified in its nuclear operating license or by the *National Nuclear Regulator* shall apply.

7.7 Criteria for network investments

(1) The *NTC* shall invest in the *TS* when the required development meets the technical and investment criteria specified in this section, or if the investment is in response to a *customer* request for *transmission* service and the cost is recoverable from the *customer* or group of *customer*s concerned in accordance with the *NERSA* approved connection charges guidelines.

(2) The *NTC* shall communicate all impacts timeously such that provision can be made for budgeting and implementation of related changes at the *customer* installation.

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

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

(5) The following key economic parameters shall have an *NERSA*-approved process of establishment:

- Discount rate
- *COUE*
- Other parameters as specified by the *NERSA* from time to time.

7.7.1 Least economic cost criteria

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

- When new *customers* are to be connected
- When investments are made in terms of improved supply reliability and/or quality to attain the limits or targets determined in section 7.6
- To determine and/or verify the desired level of network or equipment redundancy

(2) The methodology for determining the value of load or generation in neighbouring countries shall be approved by the *NERSA.*

(3) The methodology requires the cost of poor network services to be determined. These include the cost of

- interruptions
- *load shedding*
- network constraints
- poor quality of supply *(QOS).*

(4) The least-cost investment criterion equation to be satisfied can be expressed as follows:
"Value of improved QOS to *customers* > cost to the service provider to provide improved *QOS"* – (1)

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

(6) This implies that for the criteria to be satisfied:
"COUE annual value (R/kWh) x annual reduction in *EENS* to consumers (kWh) > annual cost to the service provider to reduce *EENS* (R)" - (2)

(7) The reduction in *EENS* (expected energy not served) is calculated on a probabilistic basis based on the improvements derived from the investments.

(8) The cost of unserved energy (*COUE)* is a function of the types of loads, the proportion of the total load contributed by each different type of load, the duration and *frequency* of the interruptions, the time of the day they occur, whether notice is given of the impending interruption, the indirect damage caused, the start-up costs incurred by the *customers*, the availability of *customer* backup generation and many other factors.

7.7.2 Cost reduction investments

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

- First, it is necessary to calculate the *NPV* of the proposed investment using the *DCF* methods. This shall be done by considering all cost reductions (e.g. savings in system *losses*) as positive cash flows, off-setting the required capital expenditure. Once again, sensitivity analysis with respect to the amount of capital expenditure (estimated contingency amount), the *AAICOG* (when appropriate) and future load growth scenarios is required. As before, a resulting positive *NPV* indicates that the investment is justified over the expected life of the proposed new asset.
- However, a positive *NPV* does not always indicate the optimal timing for the investment. For this reason, the second portion of the cost reduction analysis is necessary – ascertaining whether the annual extra costs incurred by the service provider for owning (levelised) and operating the proposed asset is less than all cost reductions resulting from the new asset in the first year that it is in commission.

7.7.3 Statutory investments

(1) This category of projects comprises investments that the service provider is legally required to make, irrespective of whether any economic benefit is likely to accrue, including the following:

- Investments formally requested in terms of published government policy
- Investments formally required by the National Nuclear Regulator
- Projects necessary to meet environmental legislation, e.g. the construction of oil containment dams or *EIA* and procurement of an uncontested Record of Decision prior to construction of a new line
- Expenditure to satisfy the requirements of the Occupational Health and Safety Act of 1993. This classification is intended to ensure the safety of operating and maintenance personnel who are exposed to possible danger when busy with activities related to electricity *transmission* and the safety of the general public
- Expenditure required to comply with other applicable legislation
- Expenditure required to comply with court orders
- Possible compulsory contractual commitments

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

7.7.4 Strategic investments

(1) This category of investments comprises discretionary investments made by the service provider to ensure the long term sustainability of the service provider, including:

- Site and servitude acquisition

- Expenditure, except for network expansion, required to ensure the longer term sustainability of the *service provider* which cannot be justified in terms of the least economic cost and cost reduction investment criteria (sections 7.7.1 and 7.7.2) or recovered from a *customer* or group of *customers* as a connection charge in terms of the *Transmission Tariff Code* or section 7.9 of this code. In this case, the motivation as to why the investment is genuinely needed to ensure the longer term sustainability of the *service provider* must be clearly stated, and the results of the least economic cost and/or cost reduction analyses must be documented, or reasons given why such analysis is not possible or practical. These shall include purchasing of capital spares to minimise outage duration following major plant failure, purchase of specialised vehicles and equipment to transport transformers and reactors, or implementation of industry restructuring.

- Asset replacements forming part of an asset lifecycle management plan compiled in accordance with asset management practices approved by the *NERSA.*

- Network expansion projects which can not be justified in terms of n-1 redundancy or can not be recovered from a *customer* or group of *customers* as a connection charge in terms of the

Transmission Tariff Code or section 7.9 of this code, but will provide flexibility, and avoid network redundancy in the future.

- Any other investments considered by the service provider to be justified as strategic on grounds other than those covered in this section are to be submitted to the *NERSA* for consideration on a case by case basis prior to commitment to expenditure. The results of the least economic cost and/or cost reduction analyses should still be documented to demonstrate the financial impact on the business.

7.8 Mitigation of network constraints

(1) The *NTC* has the obligation to resolve network constraints.

(2) Network constraints ("congestion") shall be regularly reviewed by the *NTC*. Economically optimal plans shall be put in place around each constraint, which may involve investment, the purchase of the constrained generation, *ancillary service* or other solutions.

7.9 Special *customer* requirements for increased reliability

(1) Should a *customer* require a more reliable or safer connection than the one provided for by the *NTC*, and the *customer* is willing to pay the total cost of providing the increased reliability in the form of an additional connection charge, the *TNSP* shall meet the requirements at the lowest overall cost.

8. Network maintenance

(1) *Participants* shall operate and maintain the equipment owned by them. The cost of such operation and maintenance shall be borne by the respective *participants* unless such equipment is proved to have been damaged by a negligent act or omission of a *participant* other than the owner, its agents or employees, in which case the responsible *participant* shall be liable for the costs of repairing such damage.

(2) *Participants* shall monitor the performance of their plant and take appropriate corrective action where deteriorating trends are detected.

(3) Maintenance scheduling shall be done in accordance with the *System Operation Code*.

(4) The *TNSP* shall agree in writing with its *customers*, details of any special maintenance requirements as well as maintenance co-ordination requirements per *transmission substation*. The *TNSP* shall provide *customers* with details of its maintenance plans and practices upon request, if these affect the quality of the connection.

APPENDIX 1: Electrical drawing symbols set and layout conventions

NRS 002 “Graphical Symbols for Electrical Diagrams” shall be used as the standard for electrical drawings, unless otherwise agreed between a service provider and a *customer*.

APPENDIX 2: Surveying, monitoring and testing for *generators*

A2.1 Introduction

This section specifies the procedures to be followed in carrying out surveying, monitoring or testing to confirm the

- compliance by *generators* with the *Grid Code*
- provision by *generators* of *ancillary services* that they are required or have agreed to provide.

A2.2 Ongoing monitoring of a *unit*'s performance

Generators shall monitor each of their *units* during normal service to confirm ongoing compliance with the applicable parts of this code. Any material deviations detected must be reported to the *System Operator* within five working days.

Generators shall keep records relating to the compliance by each of their *units* with each section of this code applicable to that *unit*, setting out such information as the *System Operator* or *TNSP* reasonably requires for assessing power system performance (including actual *unit* performance during abnormal conditions).

Within one month after the end of June and December, *generators* shall provide the *System Operator* with a report detailing the compliance or non-compliance in any material respect by each of their *units* with every section of the Network Code during the previous six-month period. The template for this appears as Appendix 3 in the Information Exchange Code.

A2.3 Procedures

<table>
<tr><th colspan="3">A2.3.1 Unit protection system GCR1</th></tr>
<tr><th>Parameter</th><th>Reference</th><th></th></tr>
<tr><td>Protection function and setting integrity study</td><td>3.1.1</td><td>APPLICABILITY AND FREQUENCY
Prototype study: All new power stations coming on line or power stations at which major refurbishment or upgrades of protection systems have taken place.

Routine review: All generators to confirm compliance every six years.

PURPOSE
To ensure that the relevant protection functions in the power station are co-ordinated and aligned with the system requirements.

PROCEDURE
Prototype:
1. Establish the system protection function and associated trip level requirements from the System Operator.
2. Derive protection functions and settings that match the power station plant, transmission plant and system requirements.
3. Confirm the stability of each protection function for all relevant system conditions.
4. Document the details of the trip levels and stability calculations for each protection function.
5. Convert protection tripping levels for each protection function into a per unit base.
6. Consolidate all settings in a per unit base for all protection functions in one document.
7. Derive actual relay dial setting details and document the relay setting sheet for all protection functions.
8. Document the position of each protection function on one single line diagram of the generating unit and associated connections.
9. Document the tripping functions for each tripping function on one tripping logic diagram.
10. Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers’ information into one document.
11. Submit to the System Operator for its acceptance and update.
12. Provide the System Operator with one original master copy and one working copy.
Review:
1. Review Items 1 to 10 above.
2. Submit to the System Operator for its acceptance and update.
3. Provide the System Operator with one original master copy and one working copy.

ACCEPTANCE CRITERIA
All protection functions are set to meet the necessary protection requirements of the transmission and power station plant with a minimal margin, optimal fault clearing times and maximum plant availability.</td></tr>
</table>

		Submit a report to the *System Operator* one month after commissioning for a prototype study or six-yearly for routine tests.
Parameter	**Reference**	
Protection integrity tests	3.1.1.	**APPLICABILITY** **Prototype test**: All new *power stations* coming on line and all other *power stations* after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified. **Routine test:/Reviews:** All *units* on: item 1 below: Review and confirm every 6 years item 2, and 3 below: at least every 12 years. . **PURPOSE** To confirm that the protection has been wired and functions according to the specifications. **PROCEDURE** 1. Apply final settings as per agreed documentation to all protection functions. 2. With the *unit* off load and de-energised, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV breaker). Document all trip test responses. 4. Apply short-circuits at all relevant protection zones and with *generator* at nominal speed excite *generator* slowly, record currents at all relevant protection functions and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short-circuits. 5. With the *unit* at nominal speed, excite *unit* slowly, recording voltages on all relevant protection functions. Confirm correct operation and correct calibration of all protection functions. Document all readings and

		responses. **ACCEPTANCE CRITERIA** All protection functions are fully operational and operate to required levels within the relay *OEM* allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard. Submit a report to the *System Operator* one month after test.

A2.3.2 ***Unit* Islanding capability GCR2**		
Parameter	**Reference**	
Unit islanding	3.1.2	**APPLICABILITY** **Prototype test:** All new *power stations* that do not have *black start* capability must test one *unit*. The prototype test shall be done from full output for the minimum required two hours. Where population of identical *units* exist at a single *power station* without *black start* capability, only one *unit* must undergo the prototype test to prove the ability, while the other *units* in such a population require only routine testing. **Routine test:** The *unit* must island from at least 60% of *MCR*, and must be sustained for at least 20 minutes, for routine tests, without tripping of the turbine, boiler, excitation system or other systems critical to sustaining an islanding condition. The *Generator* will compile a report illustrating that all the key criteria were met after 20 minutes indicating that the *unit* stabilised, giving the assurance that the *unit* would have stayed stable for a minimum of 2 hours. The *unit* shall be re-synchronised and be loaded to normal output. Routine tests need to be repeated at least every six years or following a major outage. **Continuous monitoring:** A *unit islanding* test shall be considered to be successful where, in the day-to-day running of the plant, a real condition arises in which a generating *unit* is required to island, and the islanding takes place successfully, and the islanding condition is sustained as specified under Acceptance Criteria below or is called to synchronise and completes the synchronisation successfully. **PURPOSE** To confirm that a generating *unit* that has specified it is able and/or contracted to provide an islanding service complies with the requirements. *Unit islanding* is the ability of a generating *unit* suddenly to disconnect from the *TS* by opening the *HV* breaker and to control all the necessary critical parameters automatically to a sufficient degree to maintain the turbine *generator* at speed and excited and supplying its own auxiliary load. **PROCEDURE** • The *unit* shall run at steady state conditions above 60% full load. • All protection and control systems in normal operating conditions. • No special modifications to the plant for the purpose of the test are allowed, except the installation of monitoring equipment. • The *unit* supplies all its own auxiliary load during the test. • The *unit* is disconnected from the system by opening the HV circuit breaker. • All operating within the first 2 minutes has to be noted and the *System Operator* informed for approval. • Equipment is connected to the generating *unit* that records critical parameters. The following minimum parameters are recorded:

		(a) Turbine speed (b) *Alternator* load (c) *Alternator* voltage and current (d) Exciter voltage and current (e) *Unit board* voltage (f) Anticipatory device position (where installed) (g) System *frequency* • *Unit islanding* is initiated by opening the HV Breaker. **ACCEPTANCE CRITERIA** The turbine shall settle at or close to its nominal speed and the excitation system shall remain in automatic channel, supplying all the *unit's* auxiliary load. The islanding condition shall be sustained for the agreed period. The *unit* shall successfully re-synchronise and load to contracted output.

A2.3.3 Excitation system GCR3		
Parameter	**Reference**	
Excitation and setting integrity study	3.1.3	**APPLICABILITY AND FREQUENCY** **Prototype study:** All new *power stations* coming on line or *power stations* at which major refurbishment or upgrades of excitation systems have taken place. Also, where localised changes or modifications are done, only affected part or parts shall be covered. **Routine review:** All *power stations* to confirm compliance every six years. **PURPOSE** To ensure that the excitation system in the *power station* is co-ordinated and aligned with the system requirements. **PROCEDURE** **Prototype:** 1. Establish the excitation system performance requirements from the *System Operator*. 2. Derive a suitable model for the excitation system according to IEEE 421.5 or IEC 60034.16.2. Where necessary, non-standard models (non-IEC or IEEE) shall be created. This may require *frequency* response and bode plot tests on the excitation system as described in IEEE 421.2.1990. 3. Submit the model to the *System Operator* for their acceptance. 4. Derive excitation system settings that match the *power station* plant, *transmission* plant and system requirements. This includes the settings of all parts of the excitation system such as the chop-over limits and levels, limiters, protection devices and alarms. 5. Confirm the stability of the excitation system for relevant excitation system operating conditions. 6. Document the details of the trip levels, stability calculations for each setting and function. 7. Convert the settings for each function into a per unit base and produce a high-level dynamic performance model with actual settings in p.u. values. 8. Derive actual card setting details and document the relay setting sheet for all setting functions. 9. Produce a single line diagram/block diagram of all the functions in the excitation system and indicate the signal source. 10. Document the tripping functions for each tripping on one tripping logic diagram. 11. Consolidate the detailed setting calculations, model, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant protection relay manufacturers' information into one document. 12. Submit to the *System Operator* for its acceptance and update. 13. Provide the *System Operator* with one original master copy and one working copy. **Review:**

		Review items 1 to 10 above. Submit to the *System Operator* for its acceptance and update. Provide the *System Operator* with one original master copy and one working copy update if applicable. **ACCEPTANCE CRITERIA** The excitation system is set to meet the necessary control requirements in an optimised manner for the performance of the *transmission* and *power station* plant. The excitation system operates stable both internally and on the network. Submit a report to the *System Operator* one month after commissioning for a prototype study or five to six-yearly for routine tests, within one month after expiry of the due date.

Parameter	Reference	
Excitation response tests	3.1.3	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. Also, after localised modifications or works have been carried out to the plant that will affect this performance. **Routine test:** All *generators* to perform tests on each *unit* 6-yearly after a major overhaul of plant. **PURPOSE** To confirm that the excitation system performs as per the specifications. **PROCEDURE** • With the *unit* off line, carry out *frequency* scan/bode plot tests on all circuits in the excitation system critical to the performance of the excitation system. • With the *unit* in the open circuit mode, carry out the large signal performance testing as described in IEEE 421.2 of 1990. Determine time response, ceiling voltage and voltage response. • With the *unit* synchronised and loaded, carry out the small signal performance tests according to IEE 421.2 of 1990. Also carry out power system stabiliser tests and determine damping with and without power system stabiliser. • Document all responses. **ACCEPTANCE CRITERIA** The excitation system meets the necessary control requirements in an optimised manner for the performance of the *transmission* and *power station* plant as specified. The excitation system operates stably both internally and on the network. The power system stabilisers are set for optimised damping.

A2.3.4 *Unit* reactive power capability GCR4		
Parameter	**Reference**	
Reactive power capability	3.1.4	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the reactive power capability specified is met. **PROCEDURE** The *unit* will be required to regulate the voltage on the HV *busbar* to a set level. **ACCEPTANCE CRITERIA** The *unit* shall maintain the set voltage within ±5% of the capability registered with the *System Operator* for at least one hour. Submit a report to the *System Operator* one month after the test.

A2.3.5 *Multiple-unit trip* GCR5		
Parameter	**Reference**	
Multiple- unit tripping (MUT) tests, study and survey	3.1.5	**APPLICABILITY** **Prototype tests/study/survey:** • New *power stations* coming on line: items 1 to 5 below. • *Power stations* at which major modifications or changes have been implemented on plant critical to *multiple-unit tripping*: applicable item(s) listed 1 to 5 below. **Routine assessment:** All *power stations*: item 5 below every 6 years **Routine testing**: All *power stations*. Review and confirm the status every 6 years, and test if required. **PURPOSE** To confirm that a *power station* is not subjected to unreasonable risk of *MUT* as defined in the Network Code, section 3.1.5. **PROCEDURE AND ACCEPTANCE CRITERIA** **1. Emergency supply isolation test:** On all emergency supplies (e.g. *DC* supplies) common to more than one *unit*, isolate the supply for at least one second, with the *unit* running at full load under normal operating conditions. Tests are carried out on one *unit* at a time. Where two supplies feed one common load, isolation of one supply at a time will be sufficient. Confirm that the *unit* or part of the *unit* plant does not trip. No change in the *unit* output shall take place. Document results. This test does not apply to nuclear plant. **2. Disturbance on *DC* supply survey:** On all *DC* supplies common to more than one *unit*, carry out a survey of the immunity of all devices that are part of tripping circuits, to supply voltage according to IEC specifications. All devices on *DC* supplies common to more than one *unit* that form part of tripping circuits or that can cause tripping or load reduction on a *unit* must comply with IEC specification. Document findings. **3. *Uninterruptible power supplies (UPS)* integrity testing:** On all *UPS'*s supplying critical loads that can cause tripping of more than one *unit* within the time zones specified in 3.1.5, isolate the *AC* supply to the *UPS* for a period of at least one minute. Where two *UPS'*s supply one common load, one *UPS* at a time can be isolated. Load

		equipment must resume normal operation. Document results. This test does not apply to nuclear plant. **4. Earth mat integrity inspection and testing:** Carry out an inspection and tests on all parts of the *power station* earth mat that is exposed to lightning surge entry and in close proximity to circuits vulnerable to damage that will result in tripping of more than one *unit* within the time zones specified in 3.1.5 (e.g. chimney on fossil fuel power *stations* or penstock on hydro *power stations*) Confirm that all the earthing and bonding are in place, and measure resistances to earth at bonding points. Document findings and results. **5. *MUT* risk assessment:** Identify all power supplies, air supplies, water supplies and other supplies/systems common to more than one *unit* that are likely to cause the tripping of more than one *unit* within the *MUT* categories specified in section 3.1.5. Calculate the probability of all the *MUT* risk areas for the *power station.* Document all findings, listing all risks and probabilities. No unreasonable *MUT* items as listed in 3.1.5 shall be present. Report to be submitted to the *System Operator* one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.

A2.3.6 Governing system GCR6		
Parameter	**Reference**	
Governing response tests	3.1.6	**APPLICABILITY** **Prototype test:** All new *power stations* coming on line and all other *power stations* after major modifications or refurbishment of protection or related plant. **Routine test:** All *units* to be monitored continuously. Additional tests may be requested by the *System Operator*, acting reasonably but not more than 2-yearly. **PURPOSE** To prove that the *unit* is capable of the minimum requirements for governing. **PROCEDURE** 1. *Frequency* or speed deviation to be injected on the *unit* for ten minutes. 2. Real power output of the *unit* to be measured and recorded. **ACCEPTANCE CRITERIA** Minimum requirements of the *Grid Code* are met.

A2.3.7 *Unit* restart after station blackout capability GCR7		
Parameter	**Reference**	
Restart after station blackout survey	3.1.7	**APPLICABILITY** **Prototype survey:** New *power stations* or *power stations* at which modifications have been carried out on plant critical to multiple-unit restarting. **PURPOSE** To confirm that a *power station* can restart *units* simultaneously, according to the criteria outlined in section 3.1.7, after a station blackout condition. **PROCEDURE** **1. Plant capacity survey:** • Identify all supply systems common to two or more systems (e.g. power supplies, crude oil, air, demin water). • Determine the quantity and supply rate required to simultaneously restart the number of *units* specified in section 3.1.7. • Document critical systems, required stock, study details and findings. **2. Survey of available stock:** For each of the applicable critical systems identified, document the average stock for the year, minimum stock and duration below critical stock levels. **ACCEPTANCE CRITERIA** More than 95% of the time over the year, all stocks are above critical levels. Report to be submitted to the *System Operator* one month after commissioning. Routine survey reports to be submitted one month after expiry of the due date.

A2.3.8 *Black start* capability GCR8		
Parameter	**Reference**	
*Black start*ing	3.1.8	**APPLICABILITY** **Routine test:** *Power stations* that have contracted under the *ancillary services* to supply *black start* services. Once every three years for a *partial* test and once every six years for a *full* test. **PURPOSE** To demonstrate that a *black start power station* has such capability. **PROCEDURE** • The relevant *unit* of the *power station* shall be disconnected from the system and shut down. • All external auxiliary supplies to the relevant *unit* shall be disconnected. • In the case of a station *black start*, the designated *unit*, shall be started with the relevant *unit* board being energised from an independent *auxiliary supply* within the *power station*. This *auxiliary supply* has to be in shutdown mode until the *alternator* is at a standstill. • The *unit* shall be re-synchronised to the *IPS*. **ACCEPTANCE CRITERIA** The *unit* shall be able to re-synchronise to the *IPS* within 4 hours from the start of the test. A *partial* test shall involve: • Isolation of the *unit* • Starting up of the *unit* from an independent source and • Energizing a defined portion of the *transmission* / *distribution system*. A *full* test shall involve: • Isolation of the *unit* • Starting up of the *unit* from an independent source • Energizing a defined portion of the *transmission* / *distribution system* and • The subsequent loading of the unit to prove blackstart capability. Submit a report to the *System Operator* one month after the test. The *System Operator* may request a full re-test in the event of a failed test or to re-test functions that did not meet test requirements.

A2.3.9 External supply disturbance withstand capability GCR9		
Parameter	**Reference**	
Voltage and *frequency* deviation	3.1.9	**APPLICABILITY** **Prototype survey/test:** New *power stations* coming on line or *power stations* in which major modifications have been made to plant that may be critical to system supply *frequency* or voltage magnitude deviations: item 2 for plants using dip proofing inverters (*DPI).* **Routine testing and survey:** All *power stations*: review items 1 to 3 every six years. Carry out item 3 every six years. **PURPOSE** To confirm that the *power station* and its *auxiliary supply* loads conform to the requirements of supply *frequency* and voltage magnitude deviations as specified in section 3.1.9. **SCOPE OF PLANT OR SYSTEMS** **Critical plant:** Equipment or systems that are likely to cause tripping of a *unit* or parts of a *unit* or that are likely to cause a *multiple-unit trip (MUT).* **PROCEDURE AND ACCEPTANCE CRITERIA** **1. *Frequency* deviation survey:** Carry out a survey on the capability of critical plant confirming that it will resume normal operation for *frequency* deviations as defined in section 3.1.6. A *unit* or *power station* shall not trip or unduly reduce load for system *frequency* changes in the range specified in section 3.1.6. **2. Voltage magnitude deviation survey:** Carry out a survey on the capability of critical plant confirming that it will resume normal operation for voltage deviations as defined in section 3.1.7. Document findings. Also consider protection and other tripping functions on critical plant. Document all findings. A *unit* or *power station* must not trip or unduly reduce load for system voltage changes in the range specified in section 3.1.7. **3. *Dip proofing inverter (DPI)* integrity testing:**

		DPIs or / and any other equipment must be tested according to the *OEM* requirements. Document all results. Report to be submitted to the *System Operator* one month after the testing. Routine studies and survey reports to be submitted one month after expiry of the due date.

APPENDIX 3: *Transmission* service application form

CUSTOMER'S APPLICATION FORM

Note: Where indicated, shaded areas are for completion by the Service Provider. Please provide any additional detail in the areas designated for notes.

Customer Contact Person 1 Title:

Customer's preferred form of address

Customer Contact Person 1 Initials, Surname and Job Title:

Customer Contact Person 2 Title:

Customer's preferred form of address

Customer Contact Person 2 Initials, Surname and Job Title:

Company Name:

As per Company or Closed Corporation registration document issued in Pretoria

Co/CC Reg No:

Issued by Registrar of Companies or Closed Corporations in Pretoria

Person 1 Telephone 1:	Person 1 Tele Ext:
Customer's contact no Dialling code Tele number	
Person 1 Telephone 2/Cell:	Person 1 Fax:
Alternative contact no Dialling code Tele number	Dialling code Fax/Telephone number
Person 2 Telephone 1:	Person 2 Tele Ext:
Customer's contact no Dialling code Tele number	
Person 2 Telephone 2/Cell:	Person 2 Fax:
Alternative contact no Dialling code Tele cumber	Dialling code Fax/Telephone number
Person 1 e-mail Address:	Person 2 e-mail Address:

Customer's Physical Address:

Code

Customer's personal physical location

Postal Address:

Code

Customer's preferred postal contact address

Physical connection to the *Transmission* System required? (Y/N):

If not, indicate nature of business (e.g. trader, retailer, etc.):

Type of quote required (please tick):	Feasibility:	Firm:

Notes:

Additional *customer* information

The following fields will be completed by the Service Provider

Customer ID (G)	*Customer* Type	Existing *Customer*:
***Transmission*-generated unique *customer* number**	**Indicate individual/company/partnership/other**	

Parent *Customer* ID	Credit Indicator
Indicates if *customer* is subsidiary to existing *customer*	**Indicate if other account(s) outstanding**

Application Date:	Connection Voltage (kV):	MVA:
Customer's initial application date ccyymmdd		Indicate Capacity of Connection Required

Requested Completion Date:	Estimated Monthly Consumption/Generation: MWh
When *customer* wants supply available ccyy mmdd	*Customer's* projected usage/generation for this POS

Temporary Connection:	Owner or Tenant:
If short term: period (months) for which connection required	*Customer* owns/rents property for this application

POS/Physical Connection Address:	
Longitude:	**Latitude:**

Full description of the property/title deed where supply is required: street addr, lot no, etc. No postal addresses

Usage Category (Please tick):

Industrial:	Commercial:	Distribution:	
Generation:	International:		
Other (please specify):			

Nearest Existing *Transmission* System Connection:

Transmission substation closest to POS

Other *Transmission* System Connections:

Does *customer* have other *transmission* connections/points of supply?

Standard or Enhanced Reliability Connection:

Special Instructions:

Customer's additional information regarding application

Cancel Date & Reason:

Details of why application no longer required ccyymmdd

Note that further information may be required before a quote can be provided, as described in the *Grid code*

The following fields will be completed by the Service Provider

Application ID	POS ID
Unique no for current application	**Unique no applicable to point-of-supply**

Application Type ID	NEW	INCR	DECR	CHNGE	LINES	
	New POS/ Connection:	Increase of Connec. to:	Decrease of Connec. to:	Change of Cust only	Existing lines To be moved	
	MVA	MVA	MVA	*MVA	*MVA	
	Size supply req	Size supply req	Size supply req	Current supply	Current supply	Size supply req

Note: Only 1 (one) application type ID per application

Priority Request Indicator	Priority Request Reason
High/Medium/Low	Motivation required for "high" or "low" indicators

Customer Major Activity:	File Ref	Project ID
	For special file reference only	

Grid Region:	No of Stands
	How many stands at POS address

Application Remarks:

Additional information regarding application

Ref No(s):

Details of any other *transmission* POS's linked to this *customer*

Quotation Date	Agreement Date:
Date on which application completed ccyymmdd	Date agreement completed ccyymmdd
Connection Fee Amount	Conn Fee Rect No
	Unique no
Conn Fee Payment Date	
Date of receipt of cust's payment ccyymmdd	