Preamble:

System Control is seeking to define the Northern Territory Generator Performance Standards (NT GPS) in light of foreseeable increasing applications for (and connection of) renewable generation sources in all three electricity networks (Darwin-Katherine, Tennant Creek, Alice Springs).

The System Control Technical Code (SCTC) and the Network Technical Code (NTC) primarily relate to the management of dispatchable synchronous generation and are outdated in terms of the rules required to ensure system security and reliability for a context that includes higher levels of intermittent renewable energy generation.

The Generator Performance Standards (GPS), akin to those incorporated in the National Electricity Rules but appropriate to NT context, are intended to support system security and reliability in an environment where there is a mix of synchronous/non-synchronous and dispatchable/intermittent generation.

The GPS will be incorporated into a regulatory instrument, yet to be determined. Once finalised, the updated regulatory instrument with the GPS will take precedence over relevant provisions in the existing Codes. It is proposed that the GPS will apply to all new synchronous/non-synchronous and dispatchable/non-dispatchable generators on a technology-neutral basis.

The GPS will undergo industry consultation prior to implementation. Feedback and comments on the draft GPS may be made prior to the consultation by email to Systemcontrol.Enquiryregistration@powerwater.com.au however feedback provided prior to (outside of) the formal industry consultation may not receive a formal response. The enclosed draft is intended to provide a framework of the type of technical requirements proposed for inclusion in the GPS.

Changes to this draft GPS (V0.8) from the previous (V0.7) include minor modifications throughout the document with the following sections containing more substantial changes:

5. Generating System Response to Voltage Disturbances
6. Generating System Response to Disturbances Following Contingency Events
7. Quality of Electricity Generated
12. Frequency Control
23. Inertia and fast contingency FCAS raise
24. Generator Modelling Provisions
26. Definitions

NT GPS

V0.8

Contents

1. Registration and Exemptions for Generator Registration

Standard:

Registration is required for any and all Generation sites above the thresholds determined with the Secure System Guidelines. Nominally these thresholds are based on a material step change to the power system (or subsystem) the connection point is based within.

Nominally these thresholds equate to a level equal to 2% of the system minimum demand.

Exemptions can be applied for with substantive reasoning being required. These exemptions will be reviewed on a case by case basis. Exemptions are not permanent and will be reviewed as and when required due to the dynamic nature of the power system.

2. Reactive Power Capability

Standard:

(a) A generating system or generating unit, while operating at:

Any level of active power output between its registered maximum and minimum active power output level at the connection point; and

Any voltage at the connection point within the range 0.9 to 1.1 per unit;

Shall be capable of:

(i) Continuously supplying at its connection point an amount of reactive power of at least the amount equal to the product of the rated active power of the generating unit(s) and 0.55; and

(ii) Continuously absorbing at its connection point an amount of reactive power of at least the amount equal to the product of the rated active power of the generating unit(s) and 0.55.

(b) Where a generator unit is unable to provide the required reactive power, additional dynamic reactive compensation must be provided such that equivalent capability can be achieved.

(c) Where necessary to meet the requirements of the Code, the Network Operator may require a generating system to be capable of supplying reactive power output coincident with rated active power output over a larger power factor range at the connection point than would be achieved from the combined required output from individual generating units. The need for such a requirement will be determined by power system simulation studies and any such requirement shall be included in the Access Agreement.

3. Quality of Electricity Generated

Standard:

A generating system when generating and when not generating must not produce at any of its connection points for generation:

Voltage Fluctuation:

Under normal operating conditions should be less than the “compatibility levels” defined in Table 1 of Australian Standard: AS/NZS 61000.3.7 (2001)

Harmonic Voltage Distortion:

Under normal operating conditions should be less than the “compatibility levels” defined in Table 1 of Australian Standard: AS/NZS 61000.3.6 (2001)

For non-integer harmonic distortion the emission levels shall be less than the levels defined in Section 9 of Australian Standard: AS/NZS 61000.3.6 (2001).

Voltage Unbalance:

Under normal operating conditions the average voltage unbalance measured over a 30 minute period at the connection point should not exceed the following:

For 132 kV and above:	1.0 %
For 66 kV and below:	1.5 %
For Low Voltage (e.g. 415 V):	2.0 %

4. Generating Unit Response to Frequency Disturbance

Standard:

The nominal operating frequency of the three regulated power systems is 50 Hz. Under normal operating conditions the frequency range for the Northern Territory regulated networks are:

Darwin – Katherine	50 Hz ± 0.2 Hz
Alice Springs	50 Hz ± 0.2 Hz
Tennant Creek	50 Hz ± 0.4 Hz

Under abnormal conditions the frequency will vary outside of the normal range. A generating system and each of its generating units must be capable of withstanding and remaining connected, for frequencies within in the following ranges:

- ≥47 Hz to ≤52 Hz continuously, and
- ≥45 Hz to <47 Hz for a minimum of 2 seconds,

Unless the rate of change of frequency (ROCOF) is outside the range of:

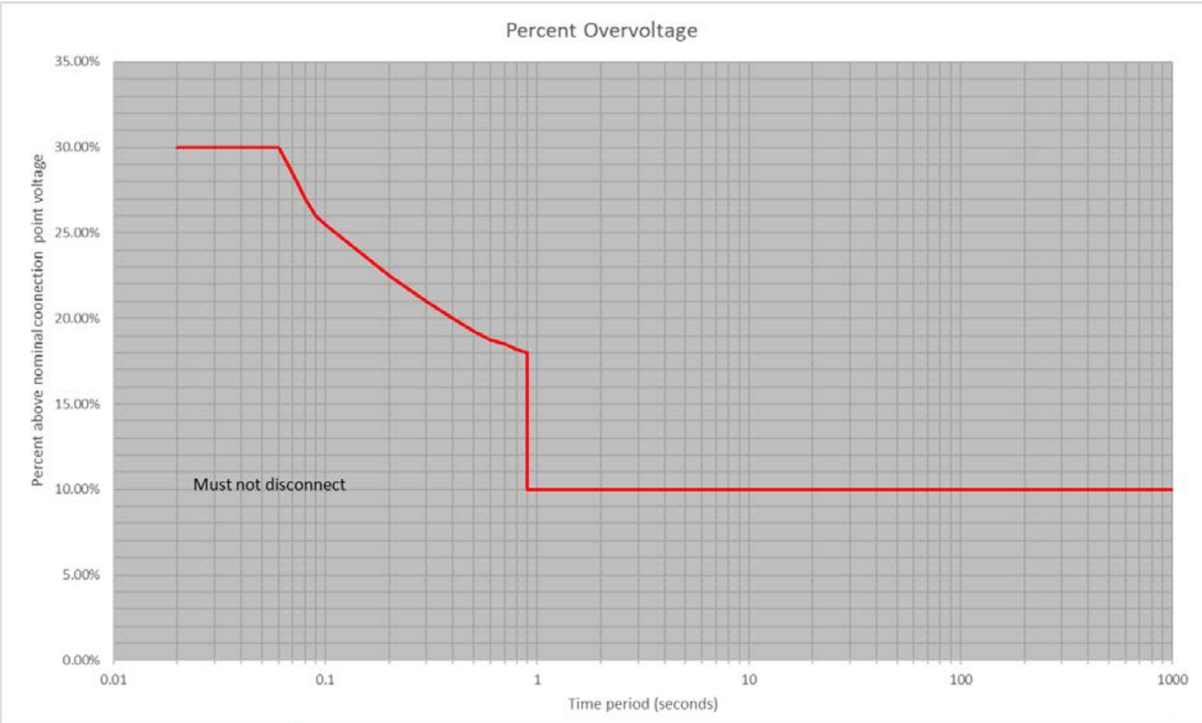
- -4 Hz/s to 4 Hz/s, for more than 0.5 seconds

5. Generating System Response to Voltage Disturbances

Standard:

A generating system and each of its generating units must be capable of continuous uninterrupted operation where a power system disturbance causes the voltage at the connection point to vary within the following ranges:

(a) For voltages over 110% of nominal voltage for the durations indicated as a minimum:

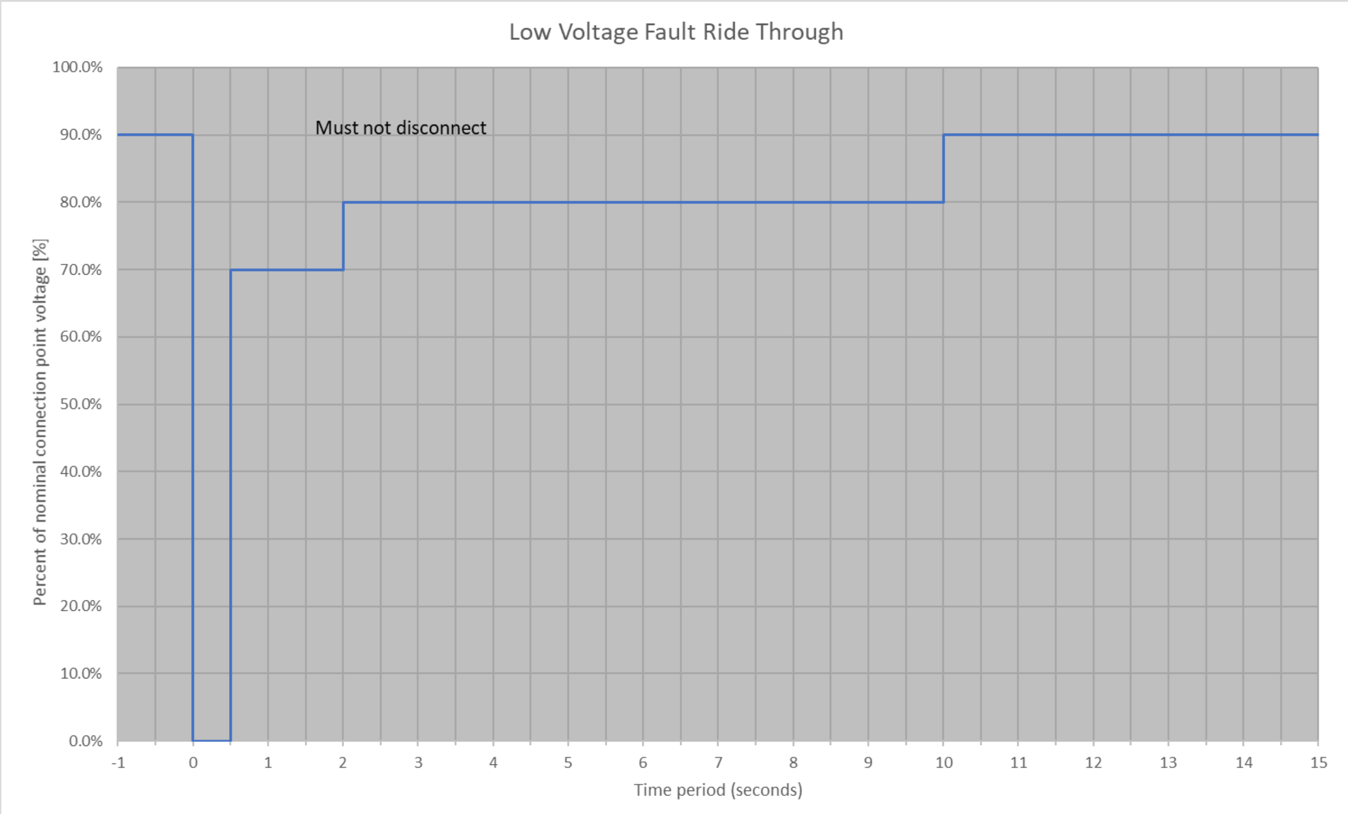


(b) For voltages between 90% - 110% of nominal voltage continuously, and when subjected to a disturbance of up to 10% of nominal voltage within this range not reducing active power due to current limitation or voltage control action;

(c) For voltages between 80% - 90% of nominal voltage for a period of at least 10 seconds;

(d) For voltages between 70% - 80% of nominal voltage for a period of at least 2 seconds, and;

(e) For voltages down to 0% of nominal voltage for up to 500 milliseconds in any one phase or combination of phases.


Low Voltage Fault Ride Through
Must not disconnect
Percent of nominal connection point voltage [%]
100.0%
90.0%
80.0%
70.0%
60.0%
50.0%
40.0%
30.0%
20.0%
10.0%
0.0%
-1
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
Time period (seconds)

6. Generating System Response to Disturbances Following Contingency Events

Standard:

(a) A generating system and each of its generating units must remain in continuous uninterrupted operation for up to fifteen disturbances within any five-minute period caused by any combination of the following events:

(i) Any non-protected credible contingency event;

(ii) Any three phase fault on the transmission system cleared by all relevant primary protection systems;

(iii) Any of the following fault types (2ph-e, ph-ph, ph-e) fault on the transmission system cleared in:
The longest time expected for relevant CBF protection to operate or;
if no CBF protection is installed the greater of 450 ms or the longest time expected for primary protection to clear the fault; and

(iv) Any fault on the distribution network cleared in:
The longest time expected for relevant CBF protection to operate; or
if no CBF protection is installed the greater of 1500 ms or the longest time expected for primary protection to clear the fault.

(b) Subject to any changed power system conditions or energy source availability beyond the Generator's reasonable control, a generating system and each of its generating units, in respect to the types of faults described above, must supply to or absorb from the power system,
to assist the maintenance of power system voltages from the time of the application of the fault, and maintained until the connection point voltage recovers to between 90% - 110% of nominal voltage following the disconnection of the faulted element:

(i) Capacitive reactive current, in addition to its pre-disturbance reactive current, of 2% of the maximum continuous current of the generating system including all operating generating units (in the absence of a disturbance) for each 1% reduction of connection point voltage below 90% of nominal voltage.

(ii) Inductive reactive current, in addition to its pre-disturbance reactive current, of 4% of the maximum continuous current of the generating system including all operating generating units (in the absence of a disturbance) for each 1% increase of connection point voltage above 110% of nominal voltage

(iii) From 100 milliseconds after disconnection of the faulted element, active power of at least 95% of the level existing just prior to the fault except;

a. where electromechanical power swings would result in this not being achieved, and;
b. where a frequency event has occurred that the generator is required to respond to.

For the purposes of (b),

(i) The reactive current response must have a rise time of no greater than 30 milliseconds after initiation of fault.

(ii) the reactive current contribution described may be measured at the applicable low voltage terminals of the generating units or reactive plant within a generating system;

(iii) the reactive current contribution required may be calculated using phase to phase, phase to ground, or sequence components of voltage. When using sequence components, the ratio of negative-sequence to positive-sequence current injection must be agreed with the System Controller and the Network Owner for various types of voltage disturbances.

7. Quality of Electricity Generated

Standard:

A generating system including each of its operating generating units and reactive plant, must not disconnect from the power system as a result of voltage fluctuation, harmonic voltage distortion and voltage unbalance conditions at the connection point within the levels specified:

(a) Voltage Fluctuations

The voltage fluctuation of supply should be less than the “compatibility levels” defined in Table 1 of Australian Standard: AS/NZS 61000.3.7 (2001).

To facilitate the application of this standard Power and Water will establish “planning levels” for the network(s) as provided for in the Australian Standard.

(b) Harmonic Voltage Distortion:

Harmonic voltage distortion level of supply should be less than the “compatibility levels” defined in Table 1 of Australian Standard: AS/NZS 61000.3.6 (2001).

For non-integer harmonic distortion the emission levels shall be less than the levels defined in Section 9 of Australian Standard: AS/NZS 61000.3.6 (2001).

To facilitate the application of this standard Power and Water will establish “planning levels” for the network(s) as provided for in the Australian Standard.

(c) Voltage Unbalance:

The average voltage unbalance measured over a 30 minute period at the connection point should not exceed the following:

For 132 kV and above:	1.0%
For 66 kV and below:	1.5%
For Low Voltage (e.g. 415 V):	2.0%

(d) When operating unsynchronised, a synchronous Generation Unit shall generate a constant voltage level with balanced phase voltages and harmonic voltage distortion equal to or less than permitted in accordance with Australian Standard AS/NZS 1359.102.3:2000 “Rotating Electrical Machines - General Requirements”.

8. Partial Load Rejection

Standard:

The generating system shall be capable of continuous uninterrupted operation during and following a power system load reduction or separation event that forms an island, provided that the load reduction is less than 50% of the Generation Unit’s nameplate rating and the load remains above minimum load.

Actual performance of the Generating Unit is to be recorded within a compliance document.

9. Protection of Generating Units from Power System Disturbances

Standard:

A Generation Unit shall be automatically disconnected from the power system in response to conditions at the relevant connection point that are not within the agreed engineering limits for operating the Generation Unit or where the conditions may impact on other Users. If reasonably required by the Network Operator or the Power System Controller, these abnormal conditions will include and are not necessarily limited to:

Loss of synchronism (out-of-step protection/pole-slip protection may need to be located on the network; this should be determined by performing power system simulation studies);
Sustained high or low frequency outside the power system frequency range 47 Hz to 52 Hz (in the case of operation below 47 Hz but at or above 45 Hz, all Generators shall remain connected to the Network Operator's network for a period of at least two seconds);
Sustained excessive Generation Unit stator current that cannot be automatically controlled;
Excessive high or low stator voltage;
Excessive voltage to frequency ratio;
Excessive negative phase sequence current;
Loss of excitation; and
Reverse power.

The actual settings of the protection equipment installed on a Generation Unit determined by the User to satisfy requirements above shall be consistent with power system performance requirements specified elsewhere in this document, and shall be approved by the Power System Controller and the Network Operator in respect of their potential to reduce power system security. They shall be such as to maximise plant availability, to assist the control of the power system under emergency conditions and to minimise the risk of inadvertent disconnection consistent with the requirements of plant safety and durability.

Neither the Network Operator nor the Power System Controller shall bear any responsibility for any loss or damage incurred by the User as a result of a fault on either the power system, the User's facility or within the Generation Unit itself.

Protection shall be provided to detect and clear faults, without system instability and without causing equipment damage.

The protection installed is required to discriminate with the Network Operator's protection on the power system.

Specific requirements and the interface point to which alarms shall be provided will be mutually decided during the detailed design phase. These alarms will be brought back to the Power System Controllers control centre via the installed SCADA system supplied by the User, as agreed to by the Network Operator.

In addition, any failure of the User's tripping supplies, protection apparatus and circuit breaker trip coils shall be alarmed within the User's installation and operating procedures put in place to ensure that prompt action is taken to remedy such failures.

Unless otherwise agreed by the Network Operator and Power System Controller, a User shall ensure that islanding of its Generation plant together with part of the Network Operator power system, cannot occur upon loss of supply from the Network Operator's power system. This should not preclude a design that allows a User to island its own Generation and plant load, thereby maintaining supply to that plant, upon loss of supply from the Network Operator's power system. Islanding shall only occur in situations where the power system is unlikely to recover from a major disturbance.

Special Protection Schemes may be detailed by the Power System Controller and the Network Operator to cater for specific islanding scenarios which will take precedence to the above paragraph.

Unless otherwise agreed by the Network Operator and Power System Controller, the User shall provide facilities to initiate islanding in the event of their system drawing more than the agreed MW/MVAr demands from the power system for a specified time.

Users shall co-operate to agree with the Network Operator the type of initiating signal and settings to ensure compatibility with other protection settings on the network and to ensure compliance with the requirements of the Network Operator

Users shall regularly maintain their protection systems at intervals of not more than 3 years. Records shall be kept of such maintenance and the Power System Controller and the Network Operator may review these. Each scheduled routine test, or any unscheduled tests that become necessary, shall include both a calibration check and an actual trip operation of the associated circuit breaker. All maintenance and testing of User owned protection shall be carried out by personnel suitably qualified and experienced in the commissioning, testing and maintenance of primary plant and secondary plant and equipment.

10. Protection Systems that Impact on Power System Security

Standard:

It is the User's responsibility to provide adequate protection (at the User's discretion) of all User owned plant to ensure the safety of the public and personnel, and to minimise damage to plant.

The Network Operator and Users shall ensure that any new equipment connected to any part of the system is protected in accordance with this requirement.

Where the connection of new equipment would affect critical fault clearance times, the protection of both new and existing equipment throughout the power system shall meet the new critical fault clearance times. Where existing protection would not meet the new critical fault clearance times, the identified protection shall be upgraded. Fault clearance time requirements may not be established until all new plant data is available and the detailed design of a User's connection or network reinforcement has commenced.

All faults of any type shall be cleared within the times specified, unless it can be established by the Network Operator that a longer clearance time would not result in the network failing to meet the performance standards set out in this document.

Protection systems shall be designed, installed and maintained in accordance with good electricity industry practice. In particular, the Network Operator shall ensure that all new protection apparatus including that installed on User's equipment complies with IEC Standard 60255 and that all new current transformers and voltage transformers comply with Australian Standard AS 60044.1 (2007) and Australian Standard AS 60044.2 (2007).

All primary equipment on the network shall be protected so that if an equipment fault occurs, the faulted equipment item is automatically removed from service by the operation of circuit breakers or fuses. Protection systems shall be designed and their settings coordinated so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in power transfer capability or in the level of service provided to Users is minimised. Protection systems shall remove faulted equipment from service in a timely manner and ensure that, where practical, those parts of the network not directly affected by a fault remain in service.

To implement a "one out of two" arrangement, complete secondary equipment redundancy is required. This includes CT and VT secondaries, auxiliary supplies, cabling and wiring, circuit breaker trip coils and batteries and inter-tripping arrangements.

For equipment connected at voltages of 66 kV and above:

Primary equipment shall be protected by a main protection system that shall remove from service only those items of primary equipment directly affected by a fault. The main protection system shall comprise two fully independent protection schemes of differing principle, connected to operate in a “one out of two” arrangement. To maintain the integrity of the two protection schemes, no electrical cross connections shall be made between them.

Primary equipment shall also be protected by a back-up protection system in addition to the main protection system. The back-up protection system shall isolate the faulted primary equipment if a circuit breaker fails to operate.

One of the independent protection schemes shall include earth fault protection.

The design of the main protection system shall make it possible to test and maintain either protection scheme without interfering with the other. It shall be possible to test and maintain either protection scheme independently without affecting the other.

Where both protection schemes require end-to-end communications, independent tele-protection signalling equipment and communication channels shall be provided. Where failure of the tele-protection signalling would result in the failure of both protection schemes to meet these requirements, independent communication bearers shall be provided.

For equipment connected at voltages of 33 kV and below:

Each item of primary equipment shall be protected by two independent protection systems. One of the independent protection systems shall be a main protection system that shall remove from service only the faulted item of primary equipment. The other independent protection system may be a back-up protection system.

At least one of the protection schemes shall include earth fault protection so as to give additional coverage for low level earth faults and to provide some remote backup.

Where a part of the distribution system may potentially form a separate island the protection system that provides protection against islanding shall comprise two fully independent protection schemes of differing principle.

Where appropriate, and with the approval of the Network Operator, a single set of high rupturing capacity (HRC) fuses may be used as a protection scheme for plant at 33 kV and below, in which case a second protection scheme would not be required to satisfy this requirements

All protection schemes on the network, including any back-up or circuit breaker failure protection scheme and associated inter-tripping, shall be kept operational at all times except when maintenance is required.

The maximum total fault clearance times are laid out below. These apply to short circuit faults of any type on primary equipment at nominal system voltage. Where critical fault clearance times exist, these times may be lower and take precedence over the times stated

For primary equipment operating at transmission system voltages the maximum total fault clearance times below apply to the nominal voltage of the circuit breaker that clears a particular fault for both minimum and maximum system conditions. For primary equipment operating at distribution system voltages the maximum total fault clearance times specified below may be applied to all circuit breakers required to clear a fault for maximum system conditions, irrespective of the nominal voltage of the circuit breaker.

Table 5 – 132 kV and 66 kV *maximum total fault clearance times* (msec)

		No CB Fail	CB Fail
132 kV and 66 kV	Local	150	400
	Remote	200	450

Table 6 – 33 kV and below *maximum total fault clearance times* (msec)

		No CB Fail	CB Fail
33 kV and below	Local	1160	1500
	Remote	Not defined	Not defined

For primary equipment operating at 132 kV and 66 kV:

Both of the protection schemes of the main protection system must operate to achieve a total fault clearance time no greater than the “No CB Fail” time given in Table 5. The backup protection system must achieve a total fault clearance time no greater than the “CB Fail” time in Table 5, except that the second protection scheme that protects against small zone faults must achieve a total fault clearance time no greater than 400 msec. For a small zone fault coupled with a circuit breaker failure, maximum total fault clearance times are not defined.

The term "local" refers to the circuit breaker(s) of a protection system where the fault is located:

Within the same substation as the circuit breaker;

For a transmission line between two substations, at or within 50% of the line impedance nearest to the substation containing the circuit breaker, provided that the line is terminated at that substation; or

For a transmission line between more than two substations, on the same line section as the substation containing the circuit breaker, provided that the line is terminated at that substation.

The term "remote" refers to all circuit breakers required to clear a fault.

For primary equipment operating at nominal voltage of 33 kV and below, the term "local" refers only to faults located within the substation in which a circuit breaker is located.

One of the major factors affecting the transient stability of the network is the fault clearance time. The critical fault clearance time is the longest time that a fault can be allowed to remain on the power system to ensure that transient instability does not occur. Critical fault clearance times are established for the various fault types at key locations. Protection then shall be set to ensure that the critical fault clearance times are achieved.

Where a critical fault clearance time to preserve system stability has been established by the Network Operator in a portion of the network:

For plant operating at voltages of 66 kV or higher, each of the two independent protection schemes shall be capable of detecting and clearing plant faults within the critical fault clearance time.

Where a critical fault clearance time exists for plant operating at 33 kV and below:

One protection scheme shall be capable of detecting and clearing plant faults within the critical fault clearance time; and

The second protection scheme is required to meet the maximum acceptable fault clearance times set out by the Network Operator

Other critical fault clearance time requirements may be imposed by the Network Operator to limit system voltage and/or frequency disturbances resulting from faults.

Protection schemes must be sufficiently sensitive to detect fault currents in the primary equipment taken into account the errors in protection apparatus and primary equipment parameters under the following system conditions:

For minimum and maximum system conditions, all protection schemes must detect and discriminate all primary equipment faults within their intended normal operating zones.

For abnormal equipment conditions involving two primary equipment outages, all primary equipment faults must be detected by one protection scheme and cleared by a protection system. Backup protection systems may be relied on for this purpose. Fault clearance times are not defined under these conditions.

Where loss of power supply to its secondary circuits would result in protection scheme performance being reduced, all protection scheme secondary circuits must have trip supply supervision. All protection scheme secondary circuits that include a circuit breaker trip coil must have trip circuit supervision, which monitor the health of the trip coil under both circuit breaker opened and closed positions.

All protective devices supplied to satisfy the protection requirements must contain such indicating, flagging, fault and event recording as is sufficient to enable the determination, after the fact, of which devices caused a particular trip. Any failure of the tripping supplies, protection apparatus and circuit breaker trip oils must be alarmed and operating procedures must be put in place to ensure that prompt action is taken to remedy such failures.

11. Protection to Trip Plant for Unstable Operation

Standard:

All Generation Units connected to the power system shall remain in synchronism following a credible contingency event.

System oscillations originating from system electromechanical characteristics, electromagnetic effect or non-linearity of system components, and triggered by any small disturbance or large disturbance in the power system, shall remain within the small disturbance rotor angle stability criteria and the power system shall return to a stable operating state following the disturbance. The small disturbance rotor angle stability criteria are set out below:

All electromechanical oscillations resulting from any small or large disturbance in the power system shall be well damped and the power system shall return to a stable operating state.

For electromechanical oscillations as a result of a large disturbance the damping ratio of the oscillation shall be at least 0.1;

For electromechanical oscillations as a result of a small disturbance, the damping ratio of the oscillation shall be at least 0.5; and

the halving time of any electromechanical oscillations shall not exceed 5 seconds

If oscillations do not comply then appropriate measures shall be taken to change the power system configuration and/or Generation dispatch and/or Generation Unit configuration so as to eliminate such oscillations. Such measures shall be taken by automatic means.

Users who may cause sub-synchronous or super-synchronous resonance oscillations shall provide appropriate measures at the planning and design stage to prevent the introduction of this problem to the power system or other Users' systems.

Short term voltage stability is concerned with the power system surviving an initial disturbance and reaching a satisfactory new steady state. Stable voltage control shall be maintained following the most severe credible contingency event.

The Network Operator and Power System Controller shall use their reasonable endeavours to ensure that all necessary calculations associated with the stable operation of the power system as described above, and for the determination of settings of equipment used to maintain that stability are carried out and to co-ordinate these calculations and determinations. The Network Operator shall facilitate establishment of the parameters and endorse the installation of power system devices that are approved by the Network Operator and Power System Controller to be necessary to assist the stable operation of the power system.

12. Frequency Control

Standard:

A generating system's power transfer to the power system must not:

Increase in response to a rise in power system frequency at the connection point; or
Decrease in response to a fall in power system frequency at the connection point;

A generating system must automatically provide a proportional:

Decrease in active power transfer to the power system in response to a rise in power system frequency at the connection point; and
Increase in active power transfer to the power system in response to a fall in power system frequency at the connection point (subject to energy source availability); and
According to a droop characteristic, able to be set between 1% and 6% droop, and
Provide this response sufficiently rapidly and sustained for a sufficient period for the Generator to be demonstrably accredited for being able to provide Frequency Control Ancillary Services.

In certain circumstances the Power System Controller may require a generating system to operate in a non-frequency responsive mode, so this capability must be provided.
The Power System Controller will determine the droop setting of all Generating Units within the Power System.

The steady state dead-band of a Generation Unit (sum of increase and decrease in power system frequency before a measurable change in the Generation Unit's active power output occurs) shall be less than 0.05 Hz.

The frequency and active power control schemes of a Generation Unit shall be adjusted for stable performance under all operating conditions, and be adequately damped.

Any control parameter used within these control schemes must not be altered without prior approval of both the Network Operator and the Power System Controller.

13. Impact on Network Capability

Standard:

The generating system has plant capabilities and control systems that are sufficient so that when connected to the power system it does not reduce any network elements power transfer capability below the level that would apply if the generating system were not connected.

If the Network Operator or Power System Controller considers that power transfer capabilities of its network would be increased through provision of additional control system facilities to a generating system (such as a power system stabiliser), the Network Operator or Power System Controller, and the Generator may negotiate for the provision of such additional control system facilities as a commercial arrangement.

14. Voltage and Reactive Power Control

Standard:

The overriding objective of a Generation Unit's voltage control system is to maintain the specified voltage range at the connection point. Each Generator must therefore provide sufficient reactive power injection into, or absorption from, the power system to meet the reactive power requirements of its loads, plus all reactive power losses required to deliver its real power output at system voltages within the ranges specified for normal operation and contingency conditions.

A generating system must have plant capabilities and control systems sufficient to ensure that:

Power system oscillations, for the frequencies of oscillation of the generating unit against any other generating unit, are adequately damped;

Operation of the generating system does not degrade the damping of any critical mode of oscillation of the power system; and

Operation of the generating system does not cause instability (including hunting of tap-changing transformer control systems) that would adversely impact other Registered Participants;

A control system used to achieve this must have:

For the purposes of disturbance monitoring and testing, permanently installed and operational, monitoring and recording facilities for key variables including each input and output; and

Facilities for testing the control system sufficient to establish its dynamic operational characteristics;

All generating systems must have a voltage control system that:

Regulates voltage at the connection point or another agreed location in the power system (including within the generating system) to within 0.5% of the set-point;

Regulates voltage in a manner that helps to support network voltages during faults;

Allows the voltage set-point to be continuously controllable in the range of at least 95% to 105% of normal voltage at the connection point or agreed location on the power system, without reliance on a tap-changing transformer; and

Has limiting devices to ensure that a voltage disturbance does not cause the system or any of its generating units to trip at the limits of its operating capability.

Each generating unit must have an excitation control system that:

Is able to operate the stator continuously at 105% of nominal voltage with rated active power output;

Has an excitation ceiling voltage of at least 2.0 times the excitation required to achieve generation at the nameplate rating for rated power factor, rated speed and nominal voltage;

Has settling times for a step change of voltage set-point of 2.5 seconds for a 5% voltage disturbance when unsynchronised for (voltage), of 5.0 seconds for a 5% voltage disturbance when synchronised for (voltage, active power, reactive power) not causing any limiting devices to operate

Is able to increase field voltage from rated field voltage to the excitation ceiling voltage in less than 50ms for static excitation, or in less than 500ms for all other excitation control systems

Has a power system stabiliser with sufficient flexibility to enable damping performance to be maximised, with characteristics as described in paragraph (c)

Has reactive current compensation settable for boost or droop

Performance Item	Units	Static Excitation	A.C. Exciter or Rotating Rectifier	Notes
Sensitivity: A sustained 0.5% error between the *voltage* reference and the sensed *voltage* will produce an excitation *change* of not less than 1.0 per unit.	Open loop gain (ratio)	200 minimum	200 minimum	1
Field *voltage* rise *time*: *Time* for field *voltage* to rise from rated *voltage* to excitation ceiling *voltage* following the application of a short duration impulse to the *voltage* reference.	second	0.05 maximum	0.5 maximum	2
Settling *time* with the *Generator synchronised* following a disturbance equivalent to a 5% step *change* in the sensed *Generator* terminal *voltage*.	second	2.5 maximum	5 maximum	3
Settling *time* with the *Generator unsynchronised* following a disturbance equivalent to a 5% step *change* in the sensed *Generator* terminal *voltage*. Shall be met at all operating points within the *Generator* capability.	second	1.5 maximum	2.5 maximum	3
Settling *time* following any disturbance that causes an excitation limiter to operate.	second	5 maximum	5 maximum	3

Notes:

1. One per unit is that field *voltage* required to produce nominal *voltage* on the air gap line of the *Generator* open circuit characteristic (Refer IEEE Standard 115-1983 – Test Procedures for Synchronous Machines).
2. Rated field *voltage* is that *voltage* required to give nominal *Generator* terminal *voltage* when the *Generator* is operating at its maximum continuous rating. Rise *time* is defined as the *time* taken for the field voltage to rise from 10% to 90% of the increment value.
3. Settling time is defined as the time taken for the Generator terminal voltage to settle and stay within an error band of ±10% of its increment value.

Any power system stabiliser that is utilised within the power system must have:

For a synchronous generating unit, measurements of rotor speed and active power output of the generating unit as inputs, and otherwise, measurements of power system frequency at the connection point and active power output of the generating unit as inputs;

Two washout filters for each input, with ability to bypass one of them if necessary;

Sufficient (and not less than two) lead-lag transfer function blocks (or equivalent number of complex poles and zeros) with adjustable gain and time-constants, to compensate fully for the phase lags due to the generating plant;

An output limiter, which for a synchronous generating unit is continually adjustable over the range of –10% to +10% of stator voltage;

Monitoring and recording facilities for key variables including inputs, output and the inputs to the lead-lag transfer function blocks; and

Facilities to permit testing of the power system stabiliser in isolation from the power system by injection of test signals, sufficient to establish the transfer function of the power system stabiliser.

Before commissioning of any power system stabiliser, its preliminary settings shall be agreed by the Network Operator and Power System Controller. The User shall propose these preliminary settings that should be derived from system simulation studies and the study results reviewed by the Network Operator and the Power System Controller.

Excitation limiters shall be provided for under excitation and over excitation and may be provided for voltage to frequency ratio. The Generation Unit shall be capable of stable continuous operation for indefinite periods while under the control of any excitation limiter. Any limiting device must not detract from the performance of any power system stabiliser, and must be coordinated with all protection systems.

The Network Operator and the Power System Controller may require that the design and operation of the control systems of a generating unit or generating system be coordinated with the existing voltage control systems within the Power System, in order to avoid or manage interactions that would adversely impact the Power System or other Users.

The Network Operator and the Power System Controller shall approve the structure and parameter settings of all components of the excitation control system, including the voltage regulator, power system stabiliser, power amplifiers and all excitation limiters. The structure and settings of the excitation control system shall not be changed, corrected or adjusted in any manner without prior written notification to the Network Operator and the Power System Controller. The Network Operator and the Power System Controller may require Generation Unit tests to demonstrate compliance with the performance requirements. The Network Operator or the Power System Controller may witness such tests.

Settings may require alteration from time to time as advised by the Network Operator or the Power System Controller. The cost of altering the settings and verifying subsequent performance shall be borne by the User, provided alterations are not made more than once in each 12 months for each Generation Unit. If more frequent changes are requested the person making that request shall pay all costs on that occasion.

15. Active Power Control

Standard:

The generating system must have an active power control system capable of:

For a scheduled generating unit or generating system:

Maintaining and changing its active power output in accordance to dispatch instructions unless responding to a network frequency deviation

Ramping its active power output linearly at a rate not less than 5% of nameplate rating per minute.

Receiving and automatically responding to AGC signals as updated (nominal update rate of once per four seconds)

Subject to energy source availability, for a non-scheduled generating unit or generating system:

Automatically adjust its active power output at a constant rate, to within 5% of the level specified in an instruction issued by a control centre

Automatically limiting its active power output to below the level instructed by a control centre

Not change its active power output within 15 minutes by more than the raise/lower commands specified in any instructions issued by a control centre unless responding to a network frequency deviation

Subject to energy source availability, for a semi-scheduled generating unit or generating system:

Automatically adjust its active power output at a constant rate, to within 5% of the level specified in an instruction issued by a control centre

Automatically limiting its active power output to below the level instructed by a control centre

Not change its active power output within 15 minutes by more than the raise/lower commands specified in any instructions issued by a control centre unless responding to a network frequency deviation

Ramping its active power output linearly at a rate approved by the Power System Controller

Receiving and automatically responding to AGC signals as updated (nominal update rate of once per four seconds)

Any and all control system used to satisfy these requirements must be adequately damped.

16. System Strength

Standard:

A generating system and each of its generating units must be capable of continuous uninterrupted operation for any short circuit ratio down a minimum of 2.0 at the connection point.

17. Remote Monitoring

Standard:

A generating system must have remote monitoring equipment and control equipment to transmit to, and receive from, the Power System Controller's control centres in real-time, the quantities that the Power System Controller reasonably requires to discharge its power system security functions, to remotely monitor performance of a Generation Unit (including its dynamic performance) where this is reasonably necessary in real time for control, planning or security of the power system; and upgrade, modify or replace any RME already installed in a power station provided that the existing RME is, in the reasonable opinion of the Network Operator or the Power System Controller, no longer fit for purpose and notice is given in writing to the relevant Users.

Any RME provided, upgraded, modified or replaced (as applicable) shall conform to an acceptable standard as agreed by the Network Operator and shall be compatible with the Network Operator's SCADA system and the nomenclature standards of the Network Operator and as agreed to by the Power System Controller

Input information to RME may include, but not be limited to, the following:

- Status indications of:
  - Circuit Breaker Open/Closed
  - Remote Generation Load Control
  - Generating Unit Operating Mode
  - Generating Unit Operating Status
  - Governor Mode
  - Governor Limiting Operation
  - Network Connection
  - Voltage Control Mode and Setpoint
- Alarms of:
  - Circuit Breaker Tripped by Protection
  - Communications Failure
  - Protection Failure
- Measure Values:
  - Gross active power output of each Generation Unit
  - Net station active power import or export at each connection point
  - Gross reactive power output of each Generation Unit
  - Net station reactive power import or export at each connection point
  - Generation Unit stator voltage
  - Generation Unit stator current
  - Generation Unit Auxiliary Active and Reactive Power

Generation Unit transformer tap position and voltage
Net station output of active energy (impulse)
Generation Unit remote Generation control high limit value
Generation Unit remote Generation control low limit value
Generation Unit remote Generation control rate limit value
For energy storage devices the available energy (in MWh)

Any other parameter or value as reasonably required.

A User is required to install remote control equipment (RCE) that is adequate to enable the Power System Controller to remotely control:

The active power output of any Generation Unit;
The reactive power output of any Generation Unit;
The voltage set-point of any Generation Unit;
The voltage control mode (where applicable); and
AGC control (where applicable);

Where a User does not provide RCE, the User shall satisfy the Network Operator and the Power System Controller that adequate arrangements are in place to allow the Power System Controller to give directions to the User for the control of the Users' Generation Units in a system emergency, and to allow the User to respond appropriately to those directions. These arrangements shall include the control of active power and reactive power.

Unless agreed otherwise, the relevant User will be responsible for the following actions at the request of the Network Operator or the Power System Controller:

Activating and de-activating RCE installed in relation to any Generation Unit; and

Setting the minimum and maximum levels to which, and a maximum rate at which, the Power System Controller will be able to adjust the performance of any Generation Unit using RCE

18. Communications Equipment

Standard:

A User shall provide electricity supplies for the RME and RCE installed in relation to its Generation Units capable of keeping these facilities available for at least eight hours following total loss of supply at the connection point for the relevant Generation Unit.

A User shall provide communications paths (with appropriate redundancy) between the RME and RCE installed at any of its Generation Units to a communications interface at the relevant power station and in a location reasonably acceptable to the Network Operator. Communications systems between this communications interface and the relevant control centre shall be the responsibility of the Network Operator unless otherwise agreed. The User shall meet the cost of the communications systems, unless otherwise determined by the Network Operator.

The Network Operator shall be responsible for radio system planning and for obtaining radio licenses for equipment used in relation to the Network Operator networks.

Telecommunications between the Power System Controller and Generators shall be established in accordance with the requirements set down below for operational communications:

Each User shall provide and maintain equipment by means of which routine and emergency control telephone calls may be established between the Users's responsible Engineer/Operator and the Power System Controller.

The facilities to be provided, including the interface requirement between the Power System Controller's equipment and the User's equipment shall be specified by the Network Operator.

Where the Network Operator or Power System Controller advises a User that a back-up speech facility to the primary facility is required, the Network Operator will provide and maintain a separate telephone link or radio installation. The costs of the equipment shall be recovered through the charge for connection.

19. Power Station Auxiliary Supplies

Standard:

In cases where a generating system takes its auxiliary supplies via a connection point through which its generation is not transferred to the network, the standards must be established as if the Generator were a load User.

20. Fault Current

Standard:

The contribution of the generating system to the fault current on the connecting network through its connection point must not exceed the contribution level that will ensure that the total fault current can be safely interrupted by the circuit breakers of the connecting network and safely carried by the connecting network for the duration of the applicable breaker fail protection system fault clearance times.

A generating system's connected plant must be capable of withstanding fault current through the connection point up to the higher of:

- The level specified by the Network Operator; or
- The highest level of current at the connection point that can be safely interrupted by the circuit breakers of the connecting network and safely carried by the connecting network for the duration of the applicable breaker fail protection system fault clearance times, as specified by the Network Operator.

A circuit breaker provided to isolate a generating unit or generating system from the network must be capable of breaking, without damage or restrike, the maximum fault currents that could reasonably be expected to flow through the circuit breaker for any fault in the network or in the generating unit or generating system.

21. Forecasts

Standard:

A generator must supply to the Power System Controller a forward forecast of the ability for each of its generating units to supply energy into the regulated power systems.

This forecast must include the following:

A month ahead forecast for availability
A week ahead forecast for availability and energy production that is within 30% of actual production
A day ahead forecast for availability and energy production that is within 10% of actual production

A 1 hour ahead forecast that is continuously updated (1 minute updates) for capacity and capability that is within 5% of actual
A 30 minute ahead forecast that is continuously updated (1 minute updates) for capacity and capability that is within 5% of actual
A real time forecast for capacity and capability that is within 5% of actual, if a generating unit is not operating at maximum rated power.

These forecasts must be provided to the Power System Controller in a format that is agreed to between parties. For forecasts external to the current day the timeliness must be within the timelines of the Market.

22. Dispatchability

Standard:

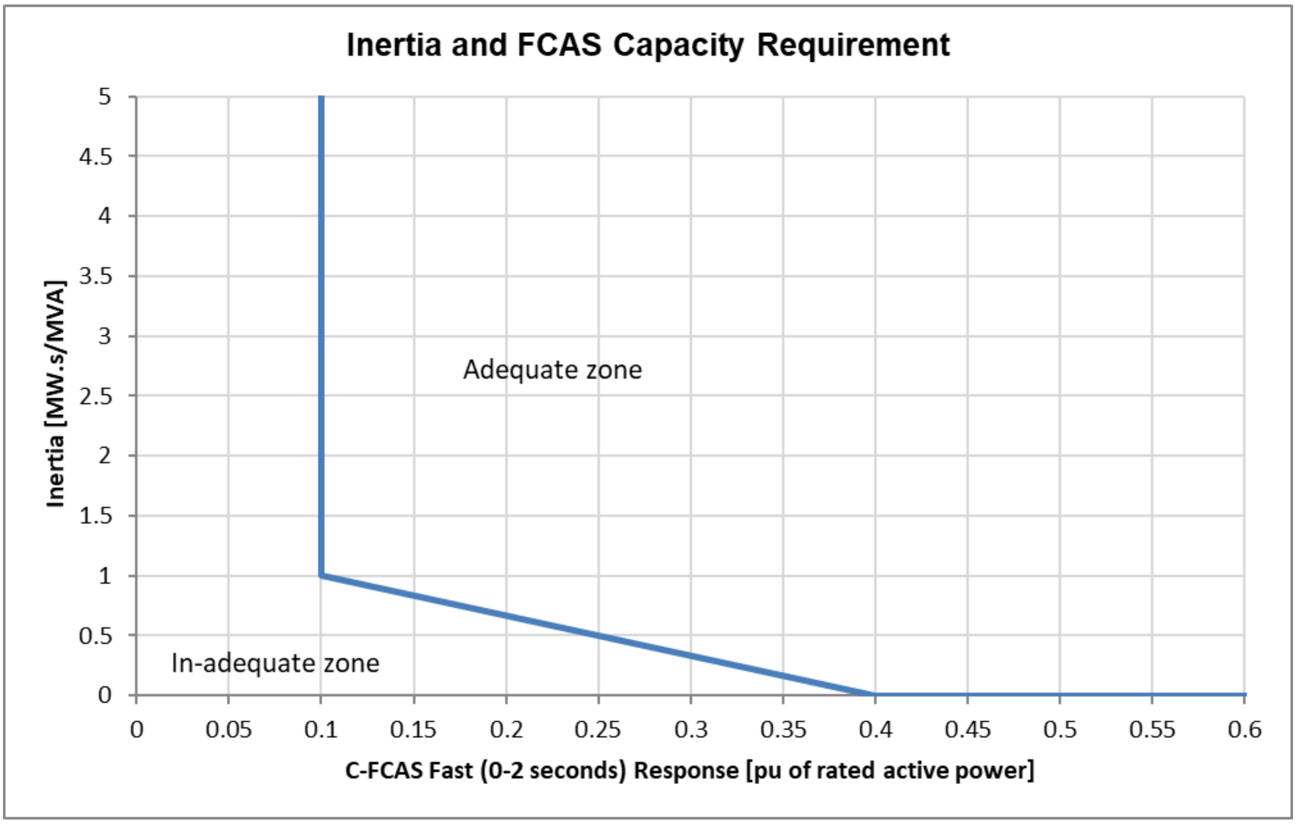
23. Inertia and fast contingency FCAS raise

Standard:

A generator system must have an adequate inertia and fast contingency FCAS (0-2 seconds) raise capability as defined by the characteristic below. The capability must be able to be dispatched up to a point within the adequate zone as shown, and can be achieved by any combination of partially loaded generator unit(s), and/or additional plant (e.g. synchronous condensers, energy storage system, etc), to achieve the required capability.

Inertia offered or provided from non-synchronous (emulated) sources needs to be assessed and accepted by the Power System Controller and Network Operator.

The Power System Controller will dispatch inertia and FCAS to enable a secure operating state in a system normal state and in the event of a credible contingency.
Minimum system inertia requirements are set by the Power System Controller and are detailed in the Secure System Guidelines. Inertia requirements are set at a system level requirement to achieve/maintain a maximum allowable RoCoF. These levels are specific to each of the three regulated power systems.



Future work for this section:

- C-FCAS capability required to be provided for 30 minutes
- C-FCAS capability to be automatically provided
- C-FCAS capability to be accredited as a trapezium relationship between dispatched output of generating system.
- Fast C-FCAS determined by time integral of response to injected frequency signal (define signal) over two seconds.
- Explain C-FCAS relationship with increase in output of generating system (0.4 C-FCAS does not necessarily require an increase to 0.4 p.u. of the rated active power).

24. Generator Modelling Provisions

Standard:

A generating unit or generating system is to have a verified dynamic model provided to both the Power System Controller and the Network Operator. The Generator is responsible for the costs of developing such a model.

In general, the modelling requirements used by AEMO have been adopted for the Northern Territory regulated networks. These can be found at: www.aemo.com.au

Specific requirements for the Northern Territory are:

- The model is to be provided in a format suitable to be used in the software suite utilised by the Power System Controller and the Network Operator (as of publication this is PSS/E v33 for RMS studies; PSCAD for EMT studies). For RMS type models the source code must be provided.
- The model should accurately represent the dynamic performance of the generating unit over the full operating range and at a minimum involve the frequency control, active power control, voltage control and reactive power control, as well as any limiters and relevant protection.
- The requirement for a PSCAD model will be determined on a case by case basis by the Power System Controller or Network Operator.
- Where both an RMS and EMT type model is provided these models are expected to deliver the same performance for balanced disturbances from an identical equivalent system. The PSCAD models are expected to more accurately represent generator performance for unbalanced disturbances, and this will be verified through either staged fault tests or actual network fault events.
- All generating units are to participate in routine periodic interval testing to demonstrate compliance with all performance standards and validate all models.
- Full modelling and validation is required for all generator units and generator systems with rated active power greater than a minimum defined by the Power System Controller.

In the case of new installations:

A model (with intended design parameters) should be provided to allow both the Network Operator and the Power System Controller to carry out any requisite studies to determine impact the network.

The model must demonstrate that performance standards can be met.

At commissioning time testing to validate the model is to be carried out to verify model performance, and alignment with expected response. Any significant discrepancies between model response and tested response are to be resolved prior to commercial operation.

A fully verified generating system and generator unit model should be provided within 3 months of commissioning. This modelling should draw on the results of any and all testing and commissioning activities and be reflective of the as left state.

In the case of existing installations:

Prior to any plant or controls upgrade/modification an updated model and parameters shall be provided representing the proposed changes and demonstrating that performance standards will be met.

This model and parameters will be provided 3 months before the planned commissioning date, so that the impact on the power system can be assessed by the Network Operator and the Power System Controller.

A fully verified site and machine specific model should be provided as within 3 months of any substantive control system changes or major upgrades which fundamentally change the existing plant. This modelling should draw on the results of any and all testing and commissioning activities and be reflective of the as left state.

25. System Integration Studies

Standard:

System Integration Studies must be performed upon any significant changes proposed by any System Participant. These studies must focus on what is required to be procured or included in the design to integrate the change into the system without negatively impacting any other System Participant or end consumers.

The scope of these studies will be negotiated with the Power System Controller and the Network Operator, and must include but is not limited to:

An assessment of the impact that the generating system will have on the power system if operated in an unconstrained manner as explicitly detailed in the preliminary design details.

An assessment of what technologies or ancillary services are required to support an unconstrained operation approach of the generating system to maintain or improve the existing state of system security and system reliability.

Identification of enabling technologies or services as options that meet the above criteria.

The cost of these studies will be borne by the System Participant or Proponent introducing the changes, and will either be carried out by the Power System Operator or Network Operator, or be undertaken by an independent third party that is mutually acceptable to all parties.

26. Definitions

adequately damped

In relation to a *control system*, when tested with a step change of a feedback input or corresponding reference, or otherwise observed, any oscillatory response at a *frequency* of:

(a) 0.05 Hz or less, has a damping ratio of at least 0.4;

(b) between 0.05 Hz and 0.6 Hz, has a halving time of 5 seconds or less (equivalent to a damping coefficient –0.14 nepers per second or less); and

(c) 0.6 Hz or more, has a damping ratio of at least 0.1.

Connection point
Either, the high voltage side of the generating system transformer(s) that connects the generating system to the transmission network, or
Where a generation collector system is directly connected to the transmission network, the generation collector bus, or
Where a generator is directly connected to the transmission network, the generator connection bus.

Continuous uninterrupted operation
In respect of a generating system or generating unit operating immediately prior to a power system disturbance:

(a) not disconnecting from the power system except under its performance standards established in clause 9 & 10;
(b) during the disturbance contributing reactive current as required by its performance standard established under clause 6; and
(c) after clearance of any electrical fault that caused the disturbance, not varying active power or reactive power unless required by its performance standards established under clauses 12, 14, and 15,

with all essential auxiliary and reactive plant remaining in service, and responding so as to not exacerbate or prolong the disturbance or cause a subsequent disturbance for other connected plant.

Generating system
A system comprising one or more generating units, and includes auxiliary or reactive plant that is located on the Generator’s side of the connection point and is necessary for the generating system to meet its performance standards.

Collector system
Network to aggregate a number of generator units to a common bus.

RoCoF
Abbreviation for “rate of change of frequency”.