Companion Guide for Testing of Assets

SYSTEM OPERATOR

TRANSPOWER

Keeping the energy flowing

Table of Contents

Glossary of Terms

Acronym	Description
ACS	Asset Capability Statement
AOPO	Asset Owner Performance Obligations
AUFLS	Automatic Under Frequency Load Shedding
AVR	Automatic Voltage Regulator
CCGT	Combined Cycle Gas Turbine
CIGRE	International Council on Large Power Systems (Conseil International des Grands Réseaux Electriques)
Code	Electricity Industry Participants code
CT	Current Transformer
DAO	Distributor Asset Owner
FIR	Fast Instantaneous Reserve
GAO	Generator Asset Owner
GXP	Grid Exit Point
GIP	Grid Injection Point
HVDC	High Voltage Direct Current
PPO	Principal Performance Obligations
SIR	Sustained Instantaneous Reserve
SVC	State VAR Compensator
VT	Voltage Transformer

Version Control

Date	Version	Description
9/9/05	Release 1.0	Amended following Electricity Commission independent review
30/8/07	V01 Approved	Re written as Explanatory Guide after Rule Change. Split into three sections that are catergorised by Asset Owner category
01/11/10	V02	Amended to reflect change from 'Rule' to 'Code' references due to formation of the Electricity Authority

Acknowledgements

The System Operator, in preparing this document, wishes to acknowledge the valuable technical assistance and positive feedback from many asset owners, technical consultants and the Electricity Commission. It would have not been possible to produce this document without the active participation of industry stakeholders.

1 About this Document

1.1 Overview

1.1.1 Introduction

This 'Asset Testing Explanatory Guide' (Explanatory Guide) provides guidance on:

- test objectives and required test results for routine tests and commissioning tests for assets including those which are the subject of an ancillary services procurement contract
- types of tests that could be carried out to achieve the test objective
- relevant standards and codes to assist asset owners in formulating test plans specific to their assts and circumstances.

The Explanatory Guide has been produced based on the Electricity Commission's consultation paper on the Routine Testing of Assets, including the draft rule changes, published in March 2007..

1.1.2 Amendments to this Explanatory Guide

The rules relating to routine testing of assets have not been finalised. This Explanatory Guide will be updated on publication and gazetting of the final rules.

Thereafter, this Explanatory Guide will be formally reviewed as provided for in current and future Policy Statements for the currency and appropriateness of the technical information contained in the document. At the time of each review, the System Operator will seek industry feedback on the content of the Explanatory Guide.

1.1.3 Content of the Explanatory Guide

The Explanatory Guide sets out the tests considered appropriate by the system operator for asset owners to demonstrate asset compliance with the AOPOs and technical codes. It sets out:

- the type of test required for each type of asset
- the output required from each test

The guide does not set define the achievement criteria for the tests that are performed.

The tests and required output included in this document have been determined taking into account:

- the relative importance of various asset data to the system operator in meeting its PPOs
- the practicality of performing the required tests
- the impact performing the tests will have on the system operator's ability to meet its PPOs during such testing
- the impact performing the tests will have on the asset itself
- International standards and best practices, customised for New Zealand power system conditions as required.

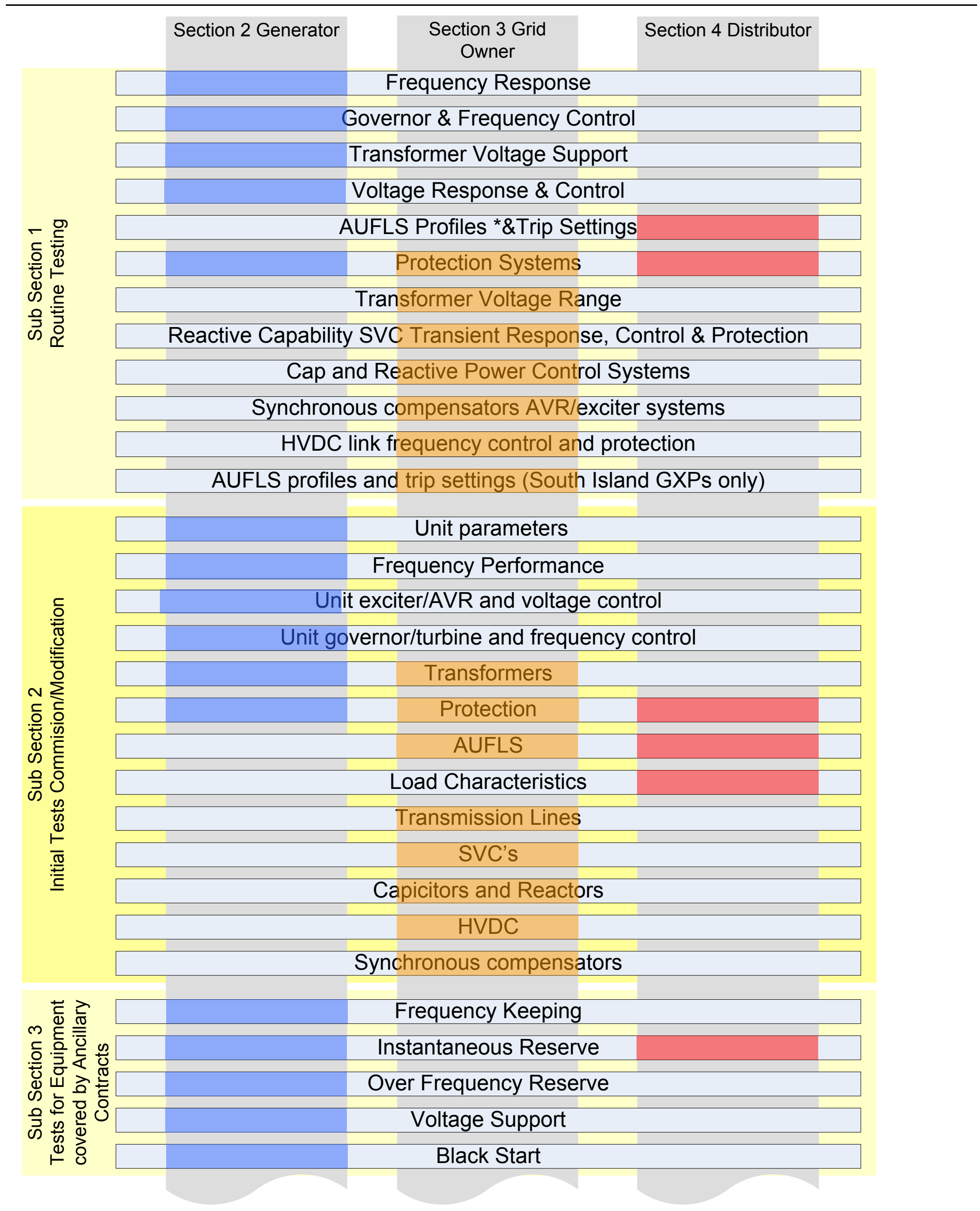
Assets with control functions such as AUFLS, AVRs, governors, SVC, and the HVDC link play a key role in the dynamic control and stability of the grid. The parameters and modelling techniques used to model these assets are therefore critical to the system operator's ability to comply with its PPOs. Therefore, they are subject to more detailed test requirements.

1.1.4 Test results

The proposed rule change requires an updated asset capability statement (ACS) following any tests. In a number of cases, the proposed rules require test results to be provided as part of the updated ACS. Therefore, the asset owner will need to provide an amended ACS that reflects the results of asset testing. The rules allow the system operator to ask for any other information that it reasonably requires to plan to comply and comply with the PPOs

1.1.5 Structure of Document

The document is arranged by Asset Owner Type then by test type, see below.


Section 2 Generator
Section 3 Grid Owner
Section 4 Distributor
Sub Section 1
Routine Testing
Frequency Response
Governor & Frequency Control
Transformer Voltage Support
Voltage Response & Control
AUFLS Profiles *&Trip Settings
Protection Systems
Transformer Voltage Range
Reactive Capability SVC Transient Response, Control & Protection
Cap and Reactive Power Control Systems
Synchronous compensators AVR/exciter systems
HVDC link frequency control and protection
AUFLS profiles and trip settings (South Island GXPs only)
Sub Section 2
Initial Tests Commision/Modification
Unit parameters
Frequency Performance
Unit exciter/AVR and voltage control
Unit governor/turbine and frequency control
Transformers
Protection
AUFLS
Load Characteristics
Transmission Lines
SVC's
Capicitors and Reactors
HVDC
Synchronous compensators
Sub Section 3
Tests for Equipment covered by Ancillary Contracts
Frequency Keeping
Instantaneous Reserve
Over Frequency Reserve
Voltage Support
Black Start

2 Generator Tests

2.1 Routine Testing

2.1.1 Overview

2.1.1.1 Overview	This section details the tests required from Generators to meet the requirements clause 8 of Part 8, Schedule 8.3 Technical Code A of the 'Code'.
2.1.1.2 Required Outcome	Generator tests are carried out to provide sufficient information (as determined by control system and plant settings and parameters) to verify: ▪ operational ranges and limits of the generating plant ▪ steady-state and dynamic performance of the plant ▪ over/under frequency performance as well as trip settings ▪ compliance of protection systems with the protection related AOPOs and Technical Codes.
2.1.1.3 Type Testing	Where two or more generating units at one generating station are completely identical, including all settings and parameter values, the system operator and the asset owner may agree that only one set of test results is required. A simplified set of tests will need to be carried out to verify that the generating units are identical before type testing is agreed to.
2.1.1.4 Structure	This part consists of the following sections

2.1.2 Generating Unit Frequency Response

2.1.2.1 Content	This section describes the outcome and test/information requirements for the under/over frequency relay tests.
2.1.2.2 Application	This section applies to all generators, except for owners of excluded generating stations, unless the Electricity Authority has issued a directive under Part 8 clause 8.21 of the 'Code'.
2.1.2.3 Purpose of tests	The frequency response testing is required to provide the system operator with frequency performance data to enable it to manage the frequency of the transmission system. An accurate representation of frequency performance: ▪ demonstrates asset owner compliance with part 8 clause 8.17 and the relevant technical codes ▪ allows the system operator to model the generating station's contribution to frequency support by remaining synchronised and sustaining at least pre-event output, when subjected to disturbances on the system.
2.1.2.4 Test outcome	The testing is required to produce a set of under and over frequency trip settings and time delays.
2.1.2.5 ACS reference	The information is required in the ACS

2.1.2.6 Tests that will achieve required outcome

Item	Description
Under Frequency Settings	Under frequency relay trip settings and time delays are verified by: ▪ injection testing; or ▪ according to the individual asset owner's standard protection equipment test procedures.
Over Frequency Settings	Over frequency tests shall be verified by: ▪ conducting un-synchronised turbine over-speed tests if this is the nature of the over frequency trip; or ▪ according to the individual Asset Owner's standard protection equipment test procedures.

2.1.3 Generating Unit Governor and Frequency Control

2.1.3.1 Content

This section describes the purpose and outcome for the generating unit governor and frequency control system tests and details of tests that will achieve required outcome.

2.1.3.2 Application

All generators except for owners of excluded generating stations unless the Electricity Authority has issued a directive under Part 8 clause 8.21 of the 'Code'.

2.1.3.3 Purpose of test

The required outcome of generating unit governor and frequency control testing is to provide the system operator with a mathematical model which describes the steady state and dynamic behaviour of the governors/turbines or frequency control systems. An accurate representation allows the system operator to model the interactions with the system and other generating units, when subjected to disturbances, and thereby control and manage the frequency of the system within the defined stability limits.

2.1.3.4 Test outcome

The testing is required to produce:

- a block diagram showing the mathematical representation of the particular manufacturer's model of governor installed or frequency control system on the generating unit
- a block diagram showing the mathematical representation of the turbine dynamics including non-linearity (e.g. gate or valve versus turbine power tabular relationship), and applicable fuel source (e.g. steam, gas, hydraulic, wind) dynamics
- a parameter list showing gains, time constants, and other settings specifically applicable to the block diagrams above.

2.1.3.5 ACS Reference

This information is required in the ACS

2.1.3.6 Tests that will achieve required outcome

2.1.3.6.1 Governor Block Diagrams/Models

Item	**Description**
Detailed Functional Description	There are many different types of governor systems in use, and consequently, a large number of possible mathematical models to describe their dynamic behaviour. There are also many different types of fuel source used for generation which consequently have different governing requirements. A mathematical model can be selected on the basis of its generic type, and an inspection of the schematics and other manufacturer documentation. Appropriate

	testing is then required to verify the model and parameters. All aspects of the plant which affect dynamic performance need to be modelled to a sufficient level to enable accurate simulation of the plant for up to 60 sec following a disturbance. For example, in hydro plant the effects of water column, surge tanks, tunnels, etc need to be included, where they significantly affect power output and response of the generating unit. Refer to: "Hydraulic Turbine and Turbine Control Models For System Dynamic Studies." 1991 IEEE paper 91 SM 462-2 PWRS, **IEEE Transactions on Power Systems, Vol. 7, No.1, February 1992.** A detailed functional description of the governing system usually includes all subsystems (e.g. turbine, conduits, governor, supplementary controls etc.) and modes of operation (e.g. Islanded mode, grid etc.) Examples of standard models in use in the New Zealand system are: **Steam Turbine Governor Models** IEEEG1 – IEEE Type 1 Speed-Governing Model ▪ With the appropriate choice of parameters, this is a recommended general model for steam turbine systems. IEEESGO –IEEE General Purpose Turbine Governor ▪ With the appropriate choice of parameters, this general purpose model gives a good representation of a steam reheat turbine. **Gas Turbine Governor Models** GAST – Single shaft gas turbine. ▪ This model represents the principal characteristics of industrial gas turbines. More detailed variations of this model are also available starting with the same name. **Hydro Turbine Governor Models** Broadly, hydro governors fall into 3 categories ▪ Transient droop (Dashpot) governors ▪ Proportional-Integral-Derivative (PID) governors ▪ Acceleration governors The first two are the most common and exist in various forms and configurations depending on the manufacturer. Several manufacturers also utilise certain features to enhance the performance of the governor system as well. There are also several types of turbine (prime mover) models: ▪ Linear flow-pmech characteristic

- Non-linear flow-pmech characteristic
- Linear flow-pmech characteristic (with relief valve)
- Non-linear flow-pmech characteristic (with relief valve)
- Kaplan turbine model
- Model with single penstock/tunnel supplying 2 machines
- Model with single penstock/tunnel supplying 4 machines

Standard models can be either split or combined governor/turbine models and are mainly modified versions of the following:

HYGOV –	Non-linear model for straightforward hydro governor and penstock with no surge chamber.
HYGOVM –	Non-linear model suitable for detailed representation of surge chamber and penstock dynamics.
IEEESGO –	Linear model for a simple hydro turbine configuration.
IEEEG2/G3	Linear models for easily obtainable or exact data of a hydro turbine representation.

Wind Turbines

Wind turbines are now becoming a more common part of New Zealand's power system, whether embedded or grid connected.

Typical models for wind turbines would include as a minimum the following:

- Blade-angle control model,
- Aerodynamic Torque model
- Shaft system representation.

Relevant Standards

IEC 60308 (1970), International Code For Testing Of Speed Governing Systems For Hydraulic Turbines.

IEEE Std 125-1988, Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.

IEC 60545 (1976-01), Guide for commissioning, operation and maintenance of hydraulic turbines.

IEEE Std 1010-1987 – (R1992) IEEE Guide for Control of Hydroelectric Power Plants

IEEE Std 1020-1988 – (R1994) IEEE Guide for Control of Small Hydroelectric Power Plants

IEEE Std122-1991 (R1997,2003) – IEEE Recommended Practice for Functional and Performance Characteristics of Control Systems for Steam Turbine-Generator Units

Governor Parameters	**<u>Step Response Test</u>** The Step Response test is used to determine the governor system time constant. It is also suitable for determining various governor parameters that can be extracted from results (for governors with proportional control or transient droop). For example, in the hydro turbine case, this test typically requires a single test carried out with the governor's speed feedback signal disconnected and replaced with a simulated signal. Any adopted methodologies will depend on the type of the turbine. For the PID Governor other particular tests are required to determine all the governor parameters. The methodology employed in this case is based on standard control theory interpretations of the PID parameters. **<u>Test Connection Measurements</u>** The following test connections are required as a minimum for the Step Response test: ▪ Unit Simulated Speed Signal - % ▪ Unit Output Power - % ▪ Servo Ram Position (wicket gate position) or valve position -% It is also advisable to record system frequency in case external disturbances occur during the test. Any step response test will be carried out after the generator has reached steady state at a load (1 -2 minutes), rather than doing a series of rapid steps which may see the generator still responding to the first step when the next step occurs. **<u>Calculations</u>** The system time constant is determined from the response curve to the step change in speed signal. The system time constant is the time taken for the response curve to reach 63.21% of its final value starting immediately after the initial step. ▪ The inferred dashpot time constant is calculated from the system time constant as indicated in Figure 2 below. Where the initial step in gate position is difficult to determine the test can be repeated with the dashpot time constant increased to a large number. **<u>Relevant Standards</u>** **ANSI/IEEE Std 125-1988**, IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators. **IEC 61064 (1991),** Acceptance Tests for Steam Turbine Speed Control systems

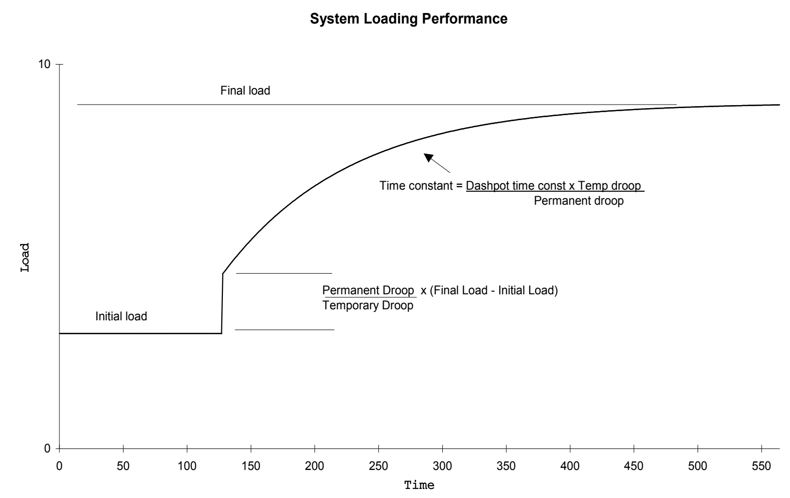


Figure 1: Step Response

2.1.3.6.2 Governor Stability

Item	Description
Methodology	Stability of a governor is its inherent ability to regulate changes in load and provide positive damping to system disturbances. There are several ways this can be determined: ▪ By simulation of the generating unit supplying an isolated resistive load at 80% of P_{max}, and +/-10% step change applied to the load. ▪ By testing the frequency response of the governor while connected to the system and loaded at 80% of P_{max}. The former method requires that the parameters and structure of the governor model be known. The latter method is commonly used on-site as a practical test to determine stability. Either method is accepted by the system operator as verification that governor has a stable response. For example, in the case of hydro turbines, these are described in further detail below (and also in Appendix A3 (Frequency response) & Appendix A4 (Computer simulation) of **IEEE Std 125-1988**. Stability is particularly important for the New Zealand power system, which comprises two island systems with a large proportion of hydro plant in both systems. Hydro plants are characterised by a water column that introduces an additional lag into the control loop, i.e. has a destabilising effect, whereas thermal plant is inherently more stable.
Simulation of Step Response (hydro turbines only)	A simulation is set up with the generating unit supplying an isolated purely resistive load representing 80% of the maximum power output of the generating unit. The load is then subjected to step changes of +10 and –10%, and the speed (frequency) deviations

checked to ensure the governor has a damped response.

The ideal response is, approximately, no more than a 15% overshoot followed by 1.5 cycles settling time to reach steady state. **IEEE Std 125-1988** defines acceptable stability if the attenuation of the 2nd speed deviation of the same sign as the first to no more than 25% of the 1st deviation. The system operator will also accept lightly damped oscillatory responses, provided steady state is achieved within 60 sec.

The system operator uses the simulation of the generating unit supplying an isolated system as a standard test to determine whether or not the governor is stable and is providing positive damping to the grid.

Calculations

According to the Nyquist criterion for stability of a control system, the open loop Nyquist plot must not encircle the critical point (-1,0).

The full open loop gain is determined by the following formula,

$$Gain = \frac{\Delta MW}{\Delta SpeedSig} \times \frac{1}{(D + 2 \cdot H \cdot s)}$$

H = Inertia constant

s = La Place Operator (substituted for jω for a sinusoidal oscillation)

D = Turbine Damping co-efficient

The magnitude and phase angle can be extracted and plotted on a Nyquist chart:

$$|Gain| = \frac{\Delta MW}{\Delta SpeedSig} \times \frac{1}{2 \cdot H \cdot (2\pi f)}$$

$$\angle Phase = Phase_{MW-SpeedSig} - 90°$$

where,

= frequency of the injected speed signal

$Phase_{MW\text{-}SpeedSig}$ = MW output 'peak' to the speed signal 'trough' phase shift

Alternatively the open loop response can be plotted on a Bode plot using the following formula,

$$Gain(dB) = 20Log[Gain]$$

The inertia constant is obtained as per generating unit parameter testing.

Stability Criteria

The definitions of gain and phase margins are shown in Figure 2 and Figure 3 respectively below. Traditional control theory suggests gain and phase margins of 3 dB and 25° are the minimum requirement for stability.

IEEE Std 125 defines suitable control with a gain margin of 8 dB and a phase margin of 30°. Either of these limits is acceptable.

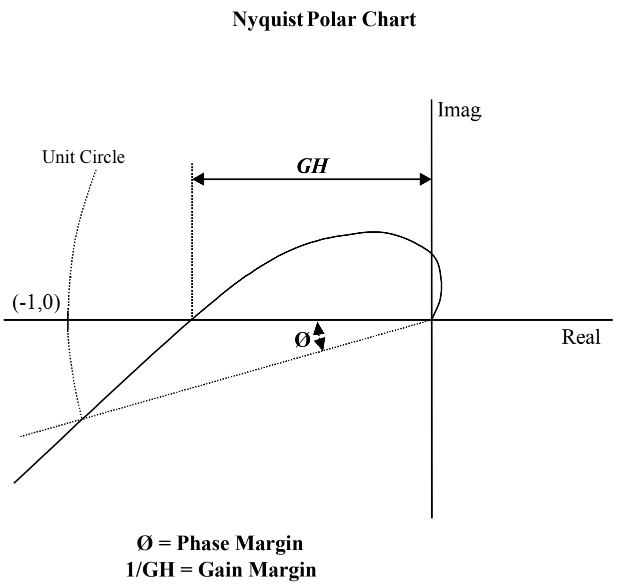


Figure 2: Nyquist Polar Chart

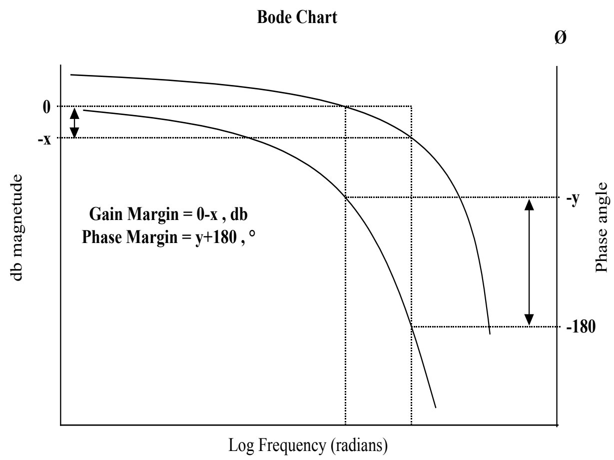


Figure 3: Bode Diagram

Relevant Standards

IEC 60308 (1970-01), "International code for testing of speed governing systems for hydraulic turbines"

ANSI/IEEE Std 125-1988, IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.

2.1.4 Generating Unit Transformer Voltage Support

2.1.4.1 Content

This section describes the test/information requirements, for the generating unit transformer voltage support tests.

2.1.4.2 Application

This section applies to all generators with a point of connection to the grid.

2.1.4.3 Purpose of test

The transformer data is required to assess the ability of transformer units to maintain point of supply voltage and reactive power capability within applicable limits.

2.1.4.4 Test outcome

The testing will result in verification of the control system of on load tap changers at a controlled node of the grid including:

- voltage setpoints
- operating deadband
- response times

2.1.4.5 ACS Reference

The information is required in the ACS

2.1.4.6 Tests that will achieve required outcome

Item	Description
Voltage control system operation	The Voltage regulating relays of on-load tap changers are to be verified by: ▪ injection testing; or ▪ according to the individual asset owner's standard equipment test procedures

2.1.5 Generating Unit Voltage Response and Control

2.1.5.1 Content

This section describes the test and information requirements for the generating unit voltage response and control and any voltage control system external to the unit (e.g. Static Var Compensator).

2.1.5.2 Application

This section applies to generators with a point of connection to the grid.

2.1.5.3 Purpose of test

The generating unit voltage response and control testing is required to provide the system operator with a mathematical model which describes the steady state and dynamic behaviour of the voltage control equipment.

An accurate representation:

- demonstrates asset owner compliance with Part 8 clauses 8.22-8.24 and the relevant technical codes
- allows the system operator to model interaction of the asset with the system and other generating stations when subjected to disturbances on the system. Such modelling assists with control of voltage stability.

2.1.5.4 Test outcomes

The tests will be required to provide:

- a **block diagram** showing the mathematical representation of the particular manufacturer's model of AVR and exciter installed on the generating unit or external to the unit.
- a **parameter list** showing gains, time constants, and other settings applicable to the block diagram above.

2.1.5.5 ACS Reference

The information is required in the ACS

2.1.5.6 Tests that will achieve required outcome

2.1.5.6.1 Synchronous Machine Exciter Block Diagrams/Models

Item	Description
Exciter Type	There are many different types of excitation systems in use, and consequently there is a large number of possible mathematical models to describe the dynamic behaviour of an excitation system Alternatively, a mathematical model can be selected on the basis of its generic type: DC, AC or ST (Static), and inspection of the schematics and other manufacturers' documentation. An appropriate model can generally be selected from the following standard types (as defined in **IEEE Std 421.5-1992**): ▪ Type DC1A – DC commutator exciter. ▪ Type DC2A – DC commutator exciter with bus fed regulator. ▪ Type DC3A – DC commutator exciter with non-continuously acting regulators. ▪ Type AC1A – Alternator-rectifier excitation system with non-controlled rectifiers and feedback from exciter field current. ▪ Type AC2A – High initial response alternator rectifier excitation system with non-controlled rectifiers and feedback from exciter field current ▪ Type AC3A – Alternator-rectifier exciter with alternator field current limiter. ▪ Type AC4A – Alternator supplied controlled-rectifier exciter. ▪ Type AC5A – Simplified rotating rectifier excitation system. ▪ Type AC6A – Alternator-rectifier excitation system with non-controlled rectifiers and system supplied electronic voltage regulator. ▪ Type ST1A – Potential-source controlled-rectifier exciter. ▪ Type ST2A – Compound-source rectifier exciter. ▪ Type ST3A – Potential or compound-source controlled-rectifier exciter with field voltage control loop. Additional functionality for individual manufacturers may be required. Where additional components such as over and under excitation limiters are fitted, appropriate block diagrams should also be provided for these components to show where they connect into the excitation model complete with a description of how and when they operate. Similarly, any standard functionality that is not used should be listed along with a note to that effect.
Settings/ Parameters	Associated with the excitation system model is a parameter list that contains the tuning settings, gains, and time constants that control the response of the excitation system. For older plant which is being re-tested a trial and error

	approach may be needed, using parameter identification and curve fitting techniques (this has been used in the past for deriving models for generating units in the NZ system). The parameters can be verified by comparing simulated responses with tested results. Tests that can be carried out are: ▪ Terminal voltage step response tests (with the machine running at no-load isolated from the system). ▪ Frequency response tests (both isolated and connected to the grid). ▪ Mvar load rejection tests (high leading Mvar, and high lagging Mvar).
Exciter Stability	The system operator criteria for testing the stability of the model is to model the generating unit and exciter isolated from the system and to apply a step change to the exciter's voltage reference. The transient response of the generating unit terminal voltage should be stable and well damped. Figure 3 of **IEEE Std 421.2-1990** shows the classical ideal control system response with 1.5 cycles to reach settling band and approximately 15% overshoot on the first oscillation. The response can be verified with a tested result. Other methods that can be performed (by test or simulation) to verify the stability of the excitation system are: ▪ Open loop frequency response Bode plots (used to obtain the gain and phase margins). Gain margin should typically be 6 dB or more, and phase margin should typically be 40° or more. ▪ Closed loop frequency response Bode plots (used to obtain the peak amplitude response and the bandwidth).
Relevant Standards	**IEEE Std 421.2-1990**: IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. **IEEE Std 421.5-1992**: IEEE Recommended Practice for Excitation System Models for Power System Stability Studies. **IEC60034-16-1-1991**: Rotating Electrical Machines - Excitation Systems for Synchronous Machines – Chapter 1, Definitions.

2.1.5.6.2 Asynchronous Machine Voltage Control Block Diagrams/Models

Item	Description
Functional Description and Block Diagram	Reactive Power consumption/production for induction machines can be achieved by either reactive power setpoint or power factor setpoint. The block diagram of the type of control is usually supplied by the manufacturer. If power factor setpoint is used, the adjustment of the setpoint according to the grid voltage level should be described.
Settings/ Parameters	Mode of control proposed should be clearly stated. For adjustable parameters, the range, deadband and rate should be stated and proposed settings supplied.
Reactive Power Compensation	Total reactive power (Mvar) of the compensation capacitor bank and step size for each step or number of steps and capacitor size (Mvar) for uniform steps should be supplied from the manufacturer's information.
Relevant Standards	**IEEE Std 112-1996**: IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.

2.1.6 Generator Protection Systems

2.1.6.1 Content

This section describes the minimum recommended routine testing for general Generator Asset Owner protection assets not already covered by previous requirements.

2.1.6.2 Application

This section applies to all generators who are required to ensure that protection systems on each side of the grid interface are coordinated under clause 4 subclause 1 of Part 8, Schedule 8.3, Technical Code A of the ‘Code’.

2.1.6.3 Purpose of test

The effectiveness and co-ordination of asset owner protection systems are fundamental to the System Operator’s ability to plan to comply and comply with the PPOs.

Testing of the protection system demonstrates generator compliance with clause 4 subclause 1 of Part 8, Schedule 8.3, Technical Code A of the ‘Code’ and provides the system operator and other asset owners with assurance that asset owners are co-operating to ensure protection is co-ordinated across the grid interface.

2.1.6.4 Test outcome

Testing of protection systems is required to confirm:

- protection is co-ordinated across the grid interface
- accuracy of primary circuit parameters and integrity of the tripping circuit components at the grid interface
- protection settings are properly identified, applied and checked to meet the outcomes set out in the ’Code’
- protection is coordinated with other asset owners at the grid interface
- protection remains coordinated, with other asset owners at the grid interface, after any modification and change at the grid interface

2.1.6.5 ACS Reference

The information is required in the ACS.

2.1.6.6 Tests that will achieve required outcome

Item	Description
Initial confirmation of coordination	Asset owners (either individually or collectively) who have not actively confirmed protection is co-ordinated should undertake an initial 'one-off' review of protection system co-ordination across the grid interface to ensure existing protection: ▪ is adequate ▪ meets the requirement for co-ordination at the grid interface. Such review should be carried out by an appropriately qualified independent expert.
Ongoing protection coordination	For asset owners to meet the AOPOs and technical codes in relation to protection each will need an effective management system to ensure the Test Outcomes set out above. . A means of ensuring the protection remains co-ordinated on an ongoing basis is for asset owners at the grid interface (individually or collectively) to engage an independent and suitably qualified person to audit the management system for protection of assets. Such audit should be conducted every 4-5 years and confirm there are effective systems in place to meet and maintain the 'Code' requirements for protection systems.
Relay tests	Relay tests should be carried out to the individual asset owner's standard equipment test procedures.

2.2 Initial Tests Commissioning/Modification

2.2.1 Overview

2.2.1.1 Content

This section details the generator tests required during commissioning or following modification to confirm asset capability and provide up to date ACS information.

Some of the tests detailed in this section duplicate those required for routine tests. (Section 2.1 Generator Tests: Routine Testing) They are included here to make this a complete and stand-alone section for commissioning and modification tests.

2.2.1.2 Application

The generator tests apply to all generators above 1 MW in size whether connected to the grid or embedded in a local network. Test requirements for generators embedded in a local network will be specified in the agreed commissioning and test plan.

2.2.1.3 Purpose of testing

Generator tests are required to provide sufficient information (as determined by control system and plant settings and parameters) to verify:

- operational ranges and limits of the generating plant
- steady-state and dynamic performance of the plant
- over/under frequency performance as well as trip settings
- compliance of protection systems with the protection related AOPOs and Technical Codes

2.2.1.4 Type Testing

Where two or more generating units at one generating station are completely identical, including all settings and parameter values, the system operator and the asset owner may agree that only one set of test results is required. A simplified set of tests will need to be carried out to verify that the generating units are identical before type testing is agreed to.

2.2.1.5 Structure

This part consists of the following sections:

2.2.2 Generating Unit Parameters

2.2.2.1 Content

This section describes the outcome and test/information requirements for the generating unit parameter tests and details of tests that will achieve required outcome.

2.2.2.2 Application

Information on generator ratings is required from all generators above 1 MW in size. Some tests are only required for grid connected generators and some embedded generators that materially affect frequency or voltage at the GXP. Refer to the ACS for the information requirements for each size of generator.

2.2.2.3 Purpose of test

During commissioning, one set of test results, either from the manufacturer or from a site test, is sufficient as the parameters are generally fixed with the construction of the machine and do not change significantly at the commissioning stage.

Testing should be carried out when the machine undergoes a major overhaul, stator and/or rotor rewinding/replacement, re-rating, modification or at any other time where machine characteristics have changed from the data last reported in the ACS.

Wherever a good indication of the unit's parameters could be obtained from a few key variables, re-testing may use this subset of tests to obtain a representative set of parameters required to confirm that the asset characteristics remain unchanged. Any large deviations of these parameters between the measured and previously recorded data may prompt the repeat of a full set of tests.

2.2.2.4 Test outcome

Generating unit parameter testing is required for the purpose of providing a mathematical model that describes the unit's steady state and dynamic behaviour.

A model of the generating unit is fundamental to any dynamic stability studies as well as load flow and fault studies. For example, in the case of synchronous generators, the standard 2-axes model is used, which is well-documented in standards and literature.

2.2.2.5 ACS Reference

The tests are required to provide:

- Characteristic Curves – Capability diagram, open & short circuit curves, V-curve, zero power factor curve, and unbalanced load-time curve.
- Machine reactances.
- Machine time constants.
- Saturation data

2.2.2.6 Tests that will achieve required outcome

2.2.2.6.1 General Machine Parameters

Item	Description	Applies to
Rated MW	The rated (or nominal) active power of the machine is defined as the machine's apparent power (MVA base) times the rated power factor.	All
MCR	The MCR is the maximum continuous active power output of the machine as measured at the generating unit terminals (excluding auxiliary losses). This may differ from the Rated MW due to turbine capability (higher or lower), or operating restrictions (lower) like fuel, hydraulic, or equipment constraints.	All
Auxiliary Power *(Active and Reactive Auxiliary Load)*	Auxiliary power is tested by direct measurement of auxiliary load MW and Mvar at rated power (or MCR if different from rated MW) of the generating unit. Whether or not the auxiliary load trips with the generating unit should also be stated. Where the auxiliary load is less than 1 MVA it can be ignored and negligible is entered in the ACS. Auxiliary losses are generally only significant in thermal (steam, gas, CCGT, geothermal) power stations.	Grid connected generators

Generating unit Inertia Constant	The generating unit's inertia constant can either be obtained from the manufacturer or derived from a full load rejection test: **By Calculation** The manufacturer typically provides the generating unit & turbine moment of inertia as a WR^2 or GD^2 value ($kg.m^2$) which is converted to a time constant (sec) by: $H = 5.483 \times 10^{-9} (WR^2)\, n_{rpm}{}^2 / S_{base}$ where: n_{rpm} = nominal speed (rpm) S_{base} = MVA base If the moment of inertia is provided in $lb.ft^2$, the inertia constant is defined as: $H = 2.31 \times 10^{-10} (WR^2)\, n_{rpm}{}^2 / S_{base}$ The inertia constant formula is divided by four if the GD^2 factor is used in place of the WR^2 factor. **By Test** The inertia can be calculated from the slope of the initial (linear) increase in speed after a load rejection. $H = 0.5 * \Delta P / (\Delta\omega/\Delta t)$ Where $\Delta\omega$ and ΔP are in pu (on frequency and machine MVA base respectively). Alternatively in terms of mechanical starting time, the inertia is calculated as follows: H = Tm / 2 * pf, Where the power factor (pf) is calculated from the full load output (not necessarily the same as $P_{Nominal}$) in MW divided by the machine MVA base. This method usually results in a higher value than that calculated effect data due to the influence of from the flywheel friction and windage.	All
Short Circuit Ratio (Synchronous Machines only)	The short circuit ratio is obtained from the open circuit and short circuit curves; it is the ratio of the field current at no-load voltage (I_{FNL}) divided by the field current corresponding to base armature current on the short circuit saturation curve (I_{FSI}). $SCR = I_{FNL} / I_{FSI}$	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.

2.2.2.6.2 Synchronous Machine Characteristic Curves

Generator Tests

Initial Tests Commissioning/Modification

Item	Description	Applies to
Generator Capability Curve	The generator capability curve shows the reactive capability of the machine and should include any restrictions on the reactive power range like under/over excitation limits, stability limits, etc. All generating units required to provide reactive support should have a Mvar range that meets the requirements of the EGRs. Curves for minimum and maximum voltage range are required in addition to those for operation at 1 p.u. This is tested while connected to the system, but it may be somewhat restricted by grid voltage constraints if the plant is older and does not have on-load tap changers on the generating unit transformers. Where plant has a generator transformer featuring a suitable on-load tapchanger, it should be possible to test the generator over its full reactive power range	Grid connected generators and embedded generators which can materially affect voltages at the GXP.
Open circuit Curve	The open circuit curve plots the no-load terminal voltage generally from 0 to 1.2 pu of the rated voltage of the machine, versus the machine excitation (field) current. Note that if the allowable maximum voltage is less than 1.2 pu then extrapolation of the curve to 1.2 will be required. Extrapolation is used to complete the lower part of the curve and produce the air-gap line. The manufacturer's information/test results are acceptable for plant which has not been rewound, modified, or re-rated.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.
Short circuit Curve	The short circuit curve plots the armature current (with the terminals short-circuited) versus the machine excitation (field) current. The manufacturer's information/test results are acceptable for plant which has not been rewound, modified, or re-rated.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.
V – Curve	The generating unit V-curve is a plot of the terminal (armature) current versus the generating unit field voltage. It is produced by setting the MW output to 0 pu and recording the field voltage and terminal current as the excitation is increased from leading power factor to lagging power factor. The test is repeated for MW = 0.25, 0.50, 0.75, and 1.0 pu. The reason for these tests is basically to confirm the steady state operation of the machine (i.e. verify X_d and X_q).	Grid connected generators.

Zero Power Factor Curve	The zero power factor saturation curve is a plot of the terminal voltage against field current for a constant armature current. It can be used to obtain the Poitier reactance. This is normally part of the manufacturing documentation, and a one off test would only be required if this information is unavailable. **IEEE Std 115-1995**, Part II, section 4.2.10 gives a method of testing this, involving the use of a 2nd machine.	Grid connected generators.
Unbalanced Load-Time Curve	Manufacturer documentation and factory tests normally provide the effect of unbalanced load on unbalanced stator current. Standard **ANSI C50.12-1982** specifies the short-circuit generator capabilities, short-time current and continuous-current unbalance requirements.	Grid connected generators.
Relevant Standards	**IEEE Std 492-1999,** IEEE Guide for Operation and Maintenance of Hydro-Generators. **IEEE Std 115-1995,** IEEE Guide: Test Procedures For Synchronous Machines. **ANSI C50.12-1982 (Reaff 1989),** Requirements for Salient Pole Synchronous Generators and Generator/Motors for Hydraulic Turbine Applications.	

2.2.2.6.3 Synchronous Machine Impedances

Item	Description	Applies to
Xd, Xq, Xd', Xq', Xd", Xq", Xl, X2, X0	These parameters are all well defined and documented by the applicable standards and literature. Many of these parameters can be determined by a number of different tests and the Generator Asset Owner can choose an appropriate method, as long as it is based on an accepted standard, or published document.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.
Use of Reactive Power Load Rejections to obtain parameters	There are several papers that describe how machine parameters can be obtained using reactive power load rejection tests (while the machine is under-excited, i.e. absorbing Mvar from the system). This method can be used to obtain the direct axis reactances and time constants. To obtain the quadrature axis reactances and time constants requires finding the loading point (MW and –Mvar) where armature current lines up with the quadrature axis (when the power factor = rotor power angle) and then using the same method as for the direct axis values.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.

	Refer to: "Derivation of Synchronous Machine Parameters from tests." F P de Mello & J R Ribeiro, **IEEE Transactions on Power Apparatus and Systems, Vol PAS-96, No 4, July/August 1977**. "Identification of Synchronous Machine Parameters Using Load Rejection Test Data." E da Costa Bortoni, J A Jardini, **IEEE Transactions on Energy Conversion, Vol 17, No.2, June 2002**. These tests will need co-ordinating with the system operator due to the possibly large fluctuations in voltage from the reactive power load rejections. They also require that the generating set's field current is measured, and that the AVR is switched to manual. Curve fitting techniques will be required to refine the parameters. These methods have previously been used in NZ to derive parameters for generating units. A range of alternative tests is given in the applicable standards: IEC 60034-4: 1985 and IEEE Std 115-1995. The system operator requires the unsaturated machine reactances, defined by **IEC 60034-4** as the rated (armature) current value of the quantity, except the synchronous reactance which is not defined as saturated. The unsaturated direct axis synchronous reactance X_d can also be readily obtained from the open & short circuit curves by: $X_d = I_{FSI} / I_{FG}$ Where: ▪ I_{FSI} is the field current corresponding to base armature current on the short circuit saturation curve, ▪ I_{FG} is the field current corresponding to the rated (base) voltage on the air-gap line from the open circuit curve. The generating unit V-curves can also be used to determine (by a trial & error process) values for X_d, X_q and S_E.	
Earthing resistance (R_e) & reactance (X_e)	Synchronous machines are usually earthed via a resistor or a distribution transformer with a resistor connected across the secondary winding. In the latter case, the resistance and reactance should be reflected to the primary side of the transformer. Usual test methods apply.	

Relevant Standards	**IEC 60034-4: 1985,** Rotating Electrical Machines – Part 4: Methods For Determining Synchronous Machine Quantities From Tests. **IEEE Std 115-1995**, IEEE Guide: Test Procedures for Synchronous Machines: Part II – Test Procedures and Parameter Determination for Dynamic analysis.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.

2.2.2.6.4 Synchronous Machine Time Constants

Item	Description	Applies to
Open Circuit Time Constants *Tdo', Tqo' (cylindrical machines only), Tdo", Tqo"*	The system operator requires the open circuit time constants (defined by **IEC 60034-4** as the time required for the slowly changing component of the open-circuit armature voltage, which is due to the direct flux following a sudden change in operating conditions), to decrease to $1/\varepsilon \approx 0.368$ of its initial value. Testing for these parameters is as per the section above.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.

2.2.2.6.5 Synchronous Machine Saturation Data

Item	Description	Applies to
Open Circuit Saturation Curve	The open circuit saturation curve yields the machine saturation parameters $S_{1.0}$ and $S_{1.2}$. The method of calculating these parameters is well documented in the literature and textbooks and are defined as: $S_{1.0} = (I_B - I_A)/I_A$ Where: ▪ I_A is the excitation current required to produce 1.0 pu terminal voltage on the air-gap line, and ▪ I_B is the excitation current required to produce 1.0 pu terminal voltage on the actual curve. Likewise, to calculate $S_{1.2}$, I_A and I_B are taken at 1.2 pu terminal voltage.	Grid connected generators and embedded generators which can materially voltage at the GXP.
	Alternatively if the values at 1.2 pu terminal voltage are not available (or cannot be achieved) they can be calculated by fitting an exponential curve ($a.V_{term}^{b}$) to data points around the rated voltage, solving for a and b, which can then be used to calculate $S_{1.2}$ at 1.2 pu terminal voltage.	

2.2.2.6.6 Asynchronous Machine Impedances

Item	Description	Applies to
R_1, X_1, X_m, R_2, X_2	The tests for obtaining these parameters are well documented in the literature and in particular the **IEEE standard 112-1996**. ▪ The no-load test can be used to obtain the self reactance of the stator (summation of X_1 and X_m). ▪ The d-c test can be used to obtain the stator resistance (R_1) ▪ The blocked-rotor test can be used to obtain the parameters R_2, and X_2, given a wound rotor type or the class type of a squirrel cage rotor at rated frequency.	Grid connected generators and embedded generators which make a material contribution to fault level at the GXP.
Relevant Standards	**IEEE Std 112-1996**, IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.	

2.2.3 *Generator Frequency Performance*

2.2.3.1 Content

This section describes the test requirements for the frequency response curves and under/over frequency relay tests.

2.2.3.2 Application

Trip settings are required from all generating stations. A frequency performance curve is only required from grid connected generators and embedded generators which materially affect frequency control.

2.2.3.3 Purpose of test

As testing is extremely difficult under normal circumstances, a real under frequency event would be required to properly verify the performance.

If the manufacturer or the generator cannot supply this information (at the planning stage), it will need to be derived by simulation and testing of the fully modelled generating unit response.

2.2.3.4 Test outcome

The required outcome of frequency response testing is to provide frequency performance data to enable frequency of the transmission system to be managed.

An accurate representation allows generating stations' contribution to frequency support to be modelled.

2.2.3.5 ACS Reference

Test are required to provide the following information:

- A frequency response curve showing output power versus frequency, showing generating set output performance (with time delays clearly shown) over a range of frequencies above and below nominal frequency; or
- A tabulation of frequency, power and time delay for the generating-set.
- A set of under and over frequency trip settings and time delays

2.2.3.6 Tests that will achieve required outcome

2.2.3.6.1 General Frequency Performance Data

Item	Description	Applies to
Settings	Under frequency relay trip settings and time delays are verified by injection testing or according to the individual Asset Owner's standard protection equipment test procedures. Over frequency tests shall be similarly verified by conducting un-synchronised turbine over-speed tests if this is the nature of the over frequency trip or according to the individual Asset Owner's standard protection equipment test procedures.	All
Frequency Performance Curve	The frequency performance curve will be supplied by the manufacturer where the power output can fall with falling frequency, compounding an under frequency event (applicable to gas turbines or combined cycle plant in particular).	Grid connected generators and embedded generators which materially affect frequency control

2.2.4 Generator Transformers

2.2.4.1 Content

This section describes the outcome and test/information requirements for the transformer tests and details of tests that will achieve required outcome.

2.2.4.2 Application

This section applies to grid connected and embedded generators which can materially affect voltage at the GXP. Some specific parameter requirements apply only to grid-connected generators (refer to the Asset Capability Statement for details).

2.2.4.3 Purpose of test

Testing is required if the transformer is modified in a way that would affect the electrical characteristics of the transformer as defined by the ACS. Modifications may include changes to the following:

- Tap changers
- Transformer bushings
- Earthing reactors
- Earthing resistors
- Cooling systems
- Any other significant auxiliary equipment

Provided that nameplate and manufacturer information is available, no further testing of the parameters will be required.

2.2.4.4 Test outcome

Transformer test data is used assess the ability of transformer units to maintain point of supply voltage and reactive power capability within applicable limits.

2.2.4.5 ACS Reference

The transformer data required from the tests is set out in the relevant section of the ACS for each generator class.

2.2.4.6 Tests that will achieve required outcome

2.2.4.6.1 General Transformer Data

Item	Description	Applies to
General Parameters	The following parameters are all available from the transformer nameplate: ▪ Nominal voltage ratio ▪ Number of windings per phase ▪ Rating HV/LV (2-winding transformers) ▪ Rating HV/MV/LV (3-winding transformers) ▪ Vector Group	Grid connected and embedded generators which can materially affect voltage at the GXP
	The remaining information shown below will be available from manufacturer documentation and test reports. ▪ Iron Losses ▪ B-H Curve ▪ Construction Type	Grid connected generators

2.2.4.6.2 Resistance and Reactance

Item	Description	Applies to
Resistance and Reactance	These parameters should all be available from the manufacturer and commissioning test reports. The values should all be referenced to the high voltage side MVA base. If the transformer has never been tested or the records are unavailable, the transformer will require testing (using the standard transformer test methods) to determine these values.	Grid connected and embedded generators which can materially affect voltage at the GXP

2.2.4.6.3 Tap Changers

Item	Description	Applies to
Type and Position	The *type* is either: ▪ On-load ▪ Off-load ▪ Fixed The *step size* is the % change of nominal voltage per step. The *tap range* is the % change (of nominal voltage) from maximum (highest voltage) to minimum (lowest voltage) The *nominal tap position* is: ▪ For off-load tap changers, the actual voltage and the tap number. ▪ For on-load tap changers, the nominal voltage and the tap number. **Note** that the numbering sequence assumed is that the lowest tap number corresponds to the lowest voltage (ratio). If the sequence is reversed it should be clearly stated. These parameters can all be determined by inspection of nameplate or manufacturer / commissioning test reports. If information is not available from the manufacturer or commissioning tests then physical testing will be required.	Grid connected and embedded generators which can materially affect voltage at the GXP
Control System Operation	Voltage regulating relays of on-load tap changers are required to be tested for grid-connected transformers to verify the following: ▪ Voltage setpoint ▪ Operating deadbands ▪ Response time	Grid connected generators

2.2.5 *Generating Unit Exciter/AVR and Voltage Control*

2.2.5.1 Content

This section describes the test requirements for the Exciter/AVR and any voltage control system external to the unit (e.g. Static Var Compensator).

2.2.5.2 Application

This section applies to grid connected and embedded generators which can materially affect voltage at the GXP.

2.2.5.3 Purpose of test

The response should be re-tested where the model and/or parameters have been changed from the last model/parameters provided to the system operator. This is likely to be the case:

- following any maintenance or servicing that involves major components of the excitation/AVR system
- where the exciter/AVR and voltage control equipment has significantly changed
- where the exciter/AVR and voltage control equipment differs from the original

specification.

2.2.5.4 Test outcome

The required outcome of Exciter/AVR or voltage control testing is required for the purpose of providing a mathematical model which describes the steady state and dynamic behaviour of the equipment.

An accurate representation allows the system operator to model interactions with the system and other generating stations, when subjected to disturbances on the system, and thereby control the voltage stability of the system.

2.2.5.5 ACS Reference

The tests are required to provide:

- a block diagram showing the mathematical representation of the particular manufacturer's model of AVR and exciter installed on the generating unit or external to the unit
- a parameter list showing gains, time constants, and other settings applicable to the block diagram above
- commissioning test results consisting of step responses (isolated operation), as tabular electronic data, to verify the tuning and stability of the exciter or voltage control system.

2.2.5.6 Tests that will achieve required outcome

2.2.5.6.1 Synchronous Machine Exciter Block Diagrams/Models

Item	Description	Applies to
Exciter Type	There are many different types of excitation systems in use, and consequently there is a large number of possible mathematical models to describe the dynamic behaviour of an excitation system. For new equipment, the manufacturer will be able to provide a suitable model for dynamic studies together with the required parameters. These would be tested and verified (and if necessary modified) at commissioning time. Alternatively, a mathematical model can be selected on the basis of its generic type: DC, AC or ST (Static), and inspection of the schematics and other manufacturers' documentation. An appropriate model can generally be selected from the following standard types (as defined in **IEEE Std 421.5-1992**): ▪ Type DC1A – DC commutator exciter. ▪ Type DC2A – DC commutator exciter with bus fed regulator. ▪ Type DC3A – DC commutator exciter with non-continuously acting regulators. ▪ Type AC1A – Alternator-rectifier excitation system with non-controlled rectifiers and feedback from exciter field current. ▪ Type AC2A – High initial response alternator rectifier excitation system with non-controlled rectifiers and feedback from exciter field current. ▪ Type AC3A – Alternator-rectifier exciter with alternator field current limiter.	Grid connected and embedded generators which can materially affect voltage at the GXP

	▪ Type AC4A – Alternator supplied controlled-rectifier exciter. ▪ Type AC5A – Simplified rotating rectifier excitation system. ▪ Type AC6A – Alternator-rectifier excitation system with non-controlled rectifiers and system supplied electronic voltage regulator. ▪ Type ST1A – Potential-source controlled-rectifier exciter. ▪ Type ST2A – Compound-source rectifier exciter. ▪ Type ST3A – Potential or compound-source controlled-rectifier exciter with field voltage control loop. Additional functionality for individual manufacturers may be required. If over and under excitation limiters are fitted, appropriate block diagrams should also be provided for these components.	
Settings/ Parameters	Associated with the excitation system model is a parameter list that contains the tuning settings, gains, and time constants that control the response of the excitation system. For modern excitation systems with digital AVRs, many of the required parameters can be obtained directly, or with scaling, from the settings documentation supplied by the manufacturer. For older plant which is being re-tested or which has never been tested, a trial and error approach may be needed, using parameter identification and curve fitting techniques (this has been used in the past for deriving models for generating units in the NZ system). The parameters can be verified by comparing simulated responses with tested results. Tests that can be carried out are: ▪ Terminal voltage step response tests (with the machine running at no-load isolated from the system). ▪ Frequency response tests (both isolated and connected to the grid). ▪ MVAr load rejection tests (high leading MVAr, and high lagging MVAr).	Grid connected and embedded generators which can materially affect voltage at the GXP
Exciter Stability	The system operator criteria for testing the stability of the model is to model the generating unit and exciter isolated from the system and to apply a step change to the exciter's voltage reference. The transient response of the generating unit terminal voltage should be stable and well damped. Figure 3 of IEEE Std 421.2-1990 shows the	

	classical ideal control system response with 1.5 cycles to reach settling band and approximately 15% overshoot on the first oscillation. The response can be verified with a tested result. Other methods that can be performed (by test or simulation) to verify the stability of the excitation system are: ▪ Open loop frequency response Bode plots (used to obtain the gain and phase margins). Gain margin should typically be 6 dB or more, and phase margin should typically be 40° or more. ▪ Closed loop frequency response Bode plots (used to obtain the peak amplitude response and the bandwidth).	
Relevant Standards	**IEEE Std 421.2-1990**: IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. **IEEE Std 421.5-1992**: IEEE Recommended Practice for Excitation System Models for Power System Stability Studies. **IEC60034-16-1-1991**: Rotating Electrical Machines - Excitation Systems for Synchronous Machines – Chapter 1, Definitions.	

2.2.5.6.2 Asynchronous Machine Voltage Control Block Diagrams/Models

Item	Description	Applies to
Functional Description and Block Diagram	Reactive Power consumption/production for induction machines can be achieved by either reactive power setpoint or power factor setpoint. The block diagram of the type of control is usually supplied by the manufacturer. If power factor setpoint is used, the adjustment of the setpoint according to the grid voltage level should be described.	Grid connected and embedded generators which can materially affect voltage at the GXP
Settings/ Parameters	Mode of control proposed should be clearly stated. For adjustable parameters, the range, deadband and rate should be stated and proposed settings supplied.	Grid connected and embedded generatiors which can materially affect voltage at the GXP

Reactive Power Compen-sation	Total reactive power (Mvar) of the compensation capacitor bank and step size for each step or number of steps and capacitor size (Mvar) for uniform steps should be supplied from the manufacturer's information.	Grid connected and embedded generators which can materially affect voltage at the GXP
Relevant Standards	**IEEE Std 112-1996**: IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.	

2.2.6 Generating Unit Governor/Turbine and Frequency Control

2.2.6.1 Content

This section describes the test requirements for the Governor/Turbine and frequency control system tests.

2.2.6.2 Application

This section applies to grid connected and embedded generators which can materially affect frequency.

2.2.6.3 Purpose of test

The response should also be re-tested where the model and/or parameters have been changed from the last model/parameters provided to the system operator. This is likely to be the case subsequent to the following events:

- following any maintenance or servicing that involves major components of the speed-governing system
- where the governor/frequency control equipment has significantly changed (prior agreement with the System Operator is required before any setting change can be made [clause 5 subclause 1 of Part 8, Schedule 8.3, Technical Code A of the 'Code'])
- where the governor/frequency control equipment differs from the original specification.

2.2.6.4 Test outcome

Governor testing is required to provide a mathematical model which describes the steady state and dynamic behaviour of the governors/turbines or frequency control systems.

An accurate representation allows the system operator to model the interactions with the system and other generating units, when subjected to disturbances, and thereby control and manage the frequency of the system within the defined stability limits.

2.2.6.5 ACS Reference

The tests are required to provide:

- a block diagram showing the mathematical representation of the particular manufacturer's model of governor installed or frequency control system on the generating unit
- a block diagram showing the mathematical representation of the turbine dynamics including non-linearity (e.g. gate or valve versus turbine power tabular relationship), and applicable fuel source (e.g. steam, gas, hydraulic, wind) dynamics
- a parameter list showing gains, time constants, and other settings applicable to the block diagrams above
- commissioning test results consisting of open-loop step responses and/or frequency response, as electronic data, of the governor or frequency control device to verify the tuning and the stability of system.
- A description of the governor functionality describing the mode of operation available and when each mode is utilised. Any functionality that is not utilised

should be clearly noted as such.

2.2.6.6 Tests that will achieve required outcome

2.2.6.6.1 Governor Block Diagrams/Models

Item	Description	Applies to
Detailed Functional Description	There are many different types of governor systems in use, and consequently, a large number of possible mathematical models to describe their dynamic behaviour. There are also many different types of fuel source used for generation which consequently have different governing requirements. For new equipment (which is largely digital based) the manufacturer will be able to provide a suitable model for dynamic studies together with the required parameters. These would be tested and verified (and if necessary modified) at commissioning time. Alternatively, a mathematical model can be selected on the basis of its generic type, and an inspection of the schematics and other manufacturer documentation. Appropriate testing is then required to verify the model and parameters. All aspects of the plant which affect dynamic performance need to be modelled to a sufficient level to enable accurate simulation of the plant for up to 60 sec following a disturbance. For example, in hydro plant the effects of water column, surge tanks, tunnels, etc need to be included, where they significantly affect power output and response of the generating unit. Refer to: "Hydraulic Turbine and Turbine Control Models For System Dynamic Studies." 1991 IEEE paper 91 SM 462-2 PWRS, IEEE Transactions on Power Systems, Vol. 7, No.1, February 1992. A detailed functional description of the governing system usually includes all subsystems (e.g. turbine, conduits, governor, supplementary controls etc.) and modes of operation (e.g. Islanded mode, grid etc.). Examples of standard models in use in the New Zealand system are: **<u>Steam Turbine Governor Models</u>** IEEEG1 – IEEE Type 1 Speed-Governing Model ▪ With the appropriate choice of parameters, this is a recommended general model for steam turbine systems. IEEESGO –IEEE General Purpose Turbine Governor ▪ With the appropriate choice of	Grid connected and embedded generators which can materially affect frequency.

	parameters, this general purpose model gives a good representation of a steam reheat turbine. **Gas Turbine Governor Models** GAST – Single shaft gas turbine. ▪ This model represents the principal characteristics of industrial gas turbines. More detailed variations of this model are also available starting with the same name. **Hydro Turbine Governor Models** Broadly, hydro governors fall into 3 categories ▪ Transient droop (Dashpot) governors ▪ Proportional-Integral-Derivative (PID) governors ▪ Acceleration governors The first two are the most common and exist in various forms and configurations depending on the manufacturer. Several manufacturers also utilise certain features to enhance the performance of the governor system as well. There are also several types of turbine (prime mover) models: ▪ Linear flow-pmech characteristic ▪ Non-linear flow-pmech characteristic ▪ Linear flow-pmech characteristic (with relief valve) ▪ Non-linear flow-pmech characteristic (with relief valve) ▪ Kaplan turbine model ▪ Model with single penstock/tunnel supplying 2 machines ▪ Model with single penstock/tunnel supplying 4 machines Standard models can be either split or combined governor/turbine models and are mainly modified versions of the following: HYGOV – Non-linear model for straightforward hydro governor and penstock with no surge chamber. HYGOVM – Non-linear model suitable for detailed representation of surge chamber and penstock dynamics. IEEESGO – Linear model for a simple hydro turbine configuration. IEEEG2/G3 Linear models for easily obtainable or exact data of a	

	hydro turbine representation. **Wind Turbines** Wind turbines are now becoming a more common part of New Zealand's power system, whether embedded or grid connected. Typical models for wind turbines would include as a minimum the following: ▪ Blade-angle control model, ▪ Aerodynamic Torque model ▪ Shaft system representation.	
Relevant Standards	**IEC 60308 (1970)**, International Code For Testing Of Speed Governing Systems For Hydraulic Turbines. **IEEE Std 125-1988**, Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators. **IEC 60545 (1976-01)**, Guide for commissioning, operation and maintenance of hydraulic turbines. **IEEE Std 1010-1987** – (R1992) IEEE Guide for Control of Hydroelectric Power Plants **IEEE Std 1020-1988** – (R1994) IEEE Guide for Control of Small Hydroelectric Power Plants **IEEE Std122-1991 (R1997,2003)** – IEEE Recommended Practice for Functional and Performance Characteristics of Control Systems for Steam Turbine-Generator Units	
Governor Parameters	**Step Response Test** The Step Response test is used to determine the governor system time constant. It is also suitable for determining various governor parameters that can be extracted from results (for governors with proportional control or transient droop). For example, in the hydro turbine case, this test typically requires a single test carried out with the governor's speed feedback signal disconnected and replaced with a simulated signal. Any adopted methodologies will depend on the type of the turbine. For the PID Governor other particular tests are required to determine all the governor parameters. The methodology employed in this case is based on standard control theory interpretations of the PID parameters. **Test Connection Measurements**	Grid connected and embedded generators which can materially affect frequency.

	The following test connections are required as a minimum for the Step Response test: ▪ Unit Simulated Speed Signal - % ▪ Unit Output Power - % ▪ Servo Ram Position (wicket gate position) or valve position -% It is also advisable to record system frequency in case external disturbances occur during the test **Calculations** The system time constant is determined from the response curve to the step change in speed signal. The system time constant is the time taken for the response curve to reach 63.21% of its final value starting immediately after the initial step. The inferred dashpot time constant is calculated from the system time constant as indicated in Figure 5 below**.** Where the initial step in gate position is difficult to determine the test can be repeated with the dashpot time constant increased to a large number.	
Relevant Standards	**ANSI/IEEE Std 125-1988**, IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators. **IEC 61064 (1991),** Acceptance Tests for Steam Turbine Speed Control systems.	

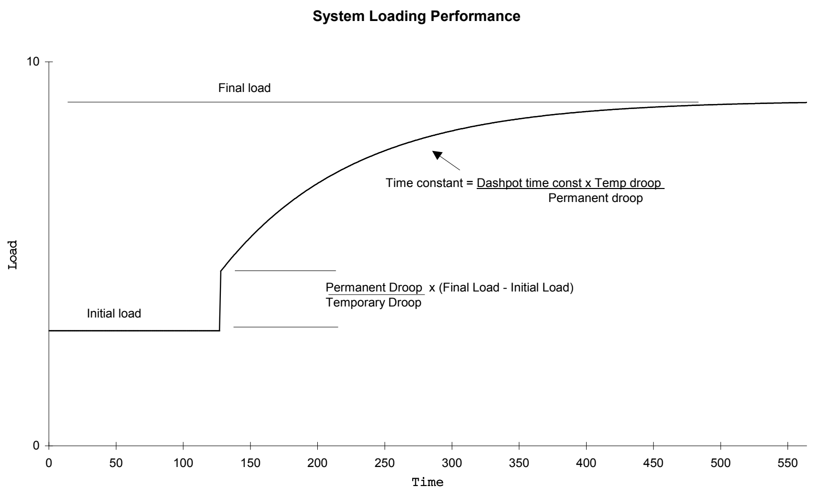


Figure 4 System Loading Performance

2.2.6.6.2 Governor Stability

Item	Description	Class
Methodology	Stability of a governor is its inherent ability to regulate changes in load and provide positive damping to system disturbances. There are several ways this can be determined: ▪ By simulation of the generating unit supplying an isolated resistive load at 80% of P_{max}, and +/-10% step change applied to the load. ▪ By testing the frequency response of the governor while connected to the system and loaded at 80% of P_{max}. The former method requires that the parameters and structure of the governor model be known. The latter method is commonly used on-site as a practical test to determine stability. Either method is accepted by the system operator as verification that governor has a stable response. For example, in the case of hydro turbines, these are described in further detail below [and also in Appendix A3 (Frequency response) & Appendix A4 (Computer simulation) of **IEEE Std 125-1988**]. Stability is particularly important for the New Zealand power system, which comprises two island systems with a large proportion of hydro plant in both systems. Hydro plants are characterised by a water column that introduces an additional lag into the control loop, i.e. has a destabilising effect, whereas thermal plant is inherently more stable.	Grid connected and embedded generators which can materially affect frequency.

Generator Tests

Initial Tests Commissioning/Modification

Simulation of Step Response (hydro turbines only)	A simulation is set up with the generating unit supplying an isolated purely resistive load representing 80% of the maximum power output of the generating unit. The load is then subjected to step changes of +10 and –10%, and the speed (frequency) deviations checked to ensure the governor has a damped response. The ideal response is, approximately, no more than a 15% overshoot followed by 1.5 cycles settling time to reach steady state. **IEEE Std 125-1988** defines acceptable stability if the attenuation of the 2nd speed deviation of the same sign as the first to no more than 25% of the 1st deviation. The system operator will also accept lightly damped oscillatory responses, provided steady state is achieved within 60 sec. The system operator uses the simulation of the generating unit supplying an isolated system as a standard test to determine whether or not the governor is stable and is providing positive damping to the grid.	Grid connected and embedded generators which can materially affect frequency.
▪ Frequency Response Test (hydro turbines only)	This test involves a series of tests carried out with the governor speed feedback signal open loop and replaced with a simulated signal. The purpose of these tests is to determine the governor frequency response characteristics. This test can also be simulated provided the model & parameters have been previously identified, and sufficient test results are available to match with simulations (to verify the model and parameters are accurate). **IEC 60308 (1970-01) & IEEE Std 125-1988** both describe the general overview of this test, however the implementation described here differs in minor details. The requirements: ▪ System Frequency - should be within ±0.1 Hz of 50 Hz during the tests. ▪ Wicket Gate Position - during the tests the wicket gate velocity must not reach the maximum rate of change and must not hit the end stops or any gate limit throughout the tests. ▪ High load – so the full effect of the water column can be seen. Typically Wicket Gate positions of 80% or greater are recommended. High Wicket Gate positions result in higher phase lags, due to the increased effect of the water column inertia, and lower system gains, due to the reduced effect of changes in Wicket Gate angle. The typical 80% gate position has been stipulated for these	Grid connected and embedded generators which can materially affect frequency.

tests to ensure the servo ram does not reach the end stop.

- Unit Output – Unit output power must follow closely to a sine wave. If the response is not a sine wave then only the fundamental is to be considered in the analysis

Calculations

According to the Nyquist criterion for stability of a control system, the open loop Nyquist plot must not encircle the critical point (-1,0).

The full open loop gain is determined by the following formula,

$$Gain = \frac{\Delta MW}{\Delta SpeedSig} \times \frac{1}{(D + 2 \cdot H \cdot s)}$$

H	= Inertia constant
s	= La Place Operator (substituted for jω for a sinusoidal oscillation)
D	= Turbine Damping co-efficient

The magnitude and phase angle can be extracted and plotted on a Nyquist chart:

$$|Gain| = \frac{\Delta MW}{\Delta SpeedSig} \times \frac{1}{2 \cdot H \cdot (2\pi f)}$$

$$\angle Phase = Phase_{MW-SpeedSig} - 90°$$

where,

f	= frequency of the injected speed signal
$Phase_{MW\text{-}SpeedSig}$	= MW output ‘peak’ to the speed signal ‘trough’ phase shift

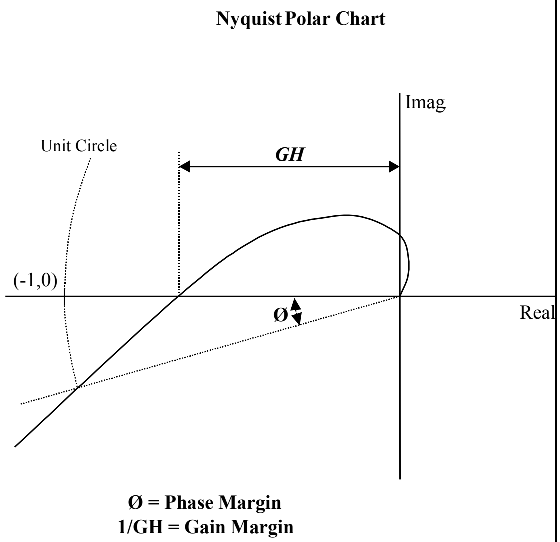
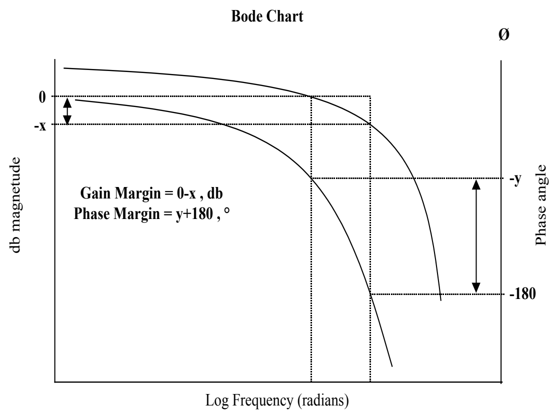
Alternatively the open loop response can be plotted on a Bode plot using the following formula,

$$Gain(dB) = 20Log[Gain]$$

The inertia constant is obtained as per generating unit parameter testing.

Stability Criteria

The definitions of gain and phase margins are shown in Figure 5 and Figure 6 respectively below. Traditional control theory suggests gain and phase margins of 3 dB

	and 25° are the minimum requirement for stability. **IEEE Std 125** defines suitable control with a gain margin of 8 dB and a phase margin of 30°. Either of these limits is acceptable.  *Figure 5: Nyquist Polar Chart*  *Figure 6: Bode Diagram*	
Relevant Standards	**IEC 60308 (1970-01)**, "International code for testing of speed governing systems for hydraulic turbines" **ANSI/IEEE Std 125-1988**, IEEE Recommended Practice for Preparation of Equipment Specifications for Speed-Governing of Hydraulic Turbines Intended to Drive Electric Generators.	

2.2.7 Generator Protection

2.2.7.1 Content	This section describes the minimum recommended routine testing for general Generator Asset Owner protection assets not already covered by previous requirements. **Note** that the System Operator does not require Asset Owners to submit protection test data. Instead, the purpose of this section is to recommend a minimum routine testing regime to ensure that the ACS assurances with regard to the compliance of protection systems with the 'Code' can be reasonably given by the Asset Owner.
2.2.7.2 Application	This section applies to generators who are required to ensure that protection systems on each side of the grid interface are coordinated under Part 8, Schedule 8.3, Technical Code A, clause 4, subclause 1. The section applies to all protection systems associated with generators, generator transformers, and GIP connection assets (transmission lines, busbars, etc)
2.2.7.3 Purpose of test	Co-ordination across the grid interface must be checked and confirmed for new or modified assets.
2.2.7.4 Test outcome	Verification of the assurance given in the Asset Owner ACS with regard to protection assets being compliant with the 'Code'.
2.2.7.5 ACS Reference	Nil
2.2.7.6 Tests that will achieve required outcome	Asset owners must confirm protection is co-ordinated across the grid interface for new or modified assets. One way of testing protection co-ordination has been achieved is for asset owners (either individually or collectively) to perform an initial review of protection system co-ordination across the grid interface to ensure existing protection: ▪ is adequate ▪ meets the requirement for co-ordination at the grid interface.

2.3 Tests for Equipment Covered by Ancillary Service Contracts

2.3.1 Overview

2.3.1.1 Content

This section details some of the tests required to meet 'Code' requirements (Procurement Plan) for testing of the ancillary services.

2.3.1.2 Type Testing

Where two or more generating units at one generating station are completely identical, including all settings and parameter values, the system operator and the asset owner may agree that only one set of test results is required. A simplified set of tests will need to be carried out to verify that the generating units are identical before type testing is agreed to.

2.3.1.3 Application

Some of the tests included in here are the same as those in previous sections. They are included in here to make this a complete stand alone section.

2.3.1.4 Structure

This part consists of the following sections:

2.3.2 Frequency Keeping

2.3.2.1 Definition

The provision of spare synchronised capacity with a response time sufficiently fast enough to control the frequency within the normal band of 49.8 to 50.2 Hertz for small changes in frequency.

2.3.2.2 Application

Frequency Keeping can be provided by generators.

2.3.2.3 Test/ Information Requirement

Test generator response

Monitoring equipment

2.3.2.4 Test outcome

The testing of the generator control equipment must verify that the generator can meet the performance requirements defined in the Procurement Plan. The monitoring equipment and response rate of the generator must also meet the 'Code' requirements.

2.3.2.5 Testing/ Information Frequency

Testing requirements are defined in the Procurement Plan.

2.3.2.6 Tests that will achieve required outcome

Not defined in this document.

2.3.3 Instantaneous Reserve

2.3.3.1 Definition

The provision of interruptible load, partially loaded spinning reserve and/or tail water depressed reserve (in each case as either fast instantaneous reserve or sustained instantaneous reserve) available to counter an under frequency excursion arising from an event. The total response expected will be fast enough and in a quantity sufficient to arrest the fall in frequency (fast instantaneous reserve), and assist in the recovery of frequency (sustained instantaneous reserve)

2.3.3.2 Application

Instantaneous reserve can be provided by both generator and distributors.

2.3.3.3 Purpose of test

The System Operator needs to ensure the integrity of the Instantaneous Reserve Ancillary Service provision by issuing requirements to service providers for assessing the Reserve Capability of their assets. This is a proactive measure to provide the System Operator with confidence that adequate reserve will be available in case of an under-frequency event.

The reason for testing reserve capability is to allow the System Operator to model and manage the total system reserve in the market. Testing provides the System Operator with verification of the FIR/SIR capability of the Generator & Distributor, in response to a standard under-frequency curve used as a proxy for under-frequency events.

2.3.3.4 Test/ Information Requirement

The response should also be provided electronically in tabular form with each measured channel in either comma or tab delimited text format.

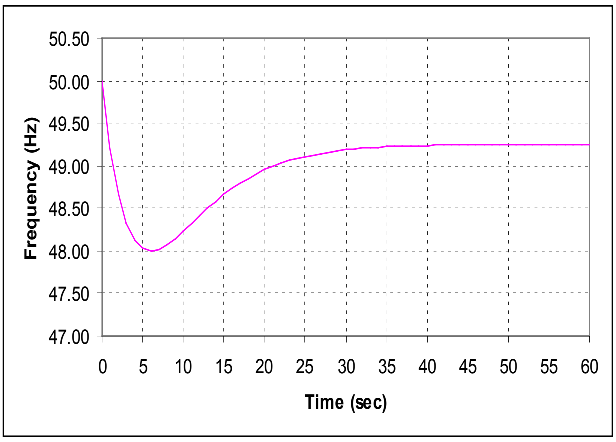
Note that Reserve Capability Testing is separate to other industry requirements of ongoing monitoring to record pre/post- event data.

2.3.3.5 Testing/ Information Frequency

Testing requirements are defined in he Procurement Plan.

2.3.3.6 Tests that will achieve required outcome

2.3.3.6.1 Generator FIR/SIR capability

Item	Description
General	This section details the basic technical requirements for all Generator Asset Owners (GAOs) offering Fast Instantaneous Reserve (FIR) and/or Sustained Instantaneous Reserve (SIR). The standard under-frequency curve is defined by the formula: Freq(t) = 49.25 + (0.75 – 0.8055t) * exp(-0.1973t) The plot of this formula is shown in Figure 7 below:  *Figure 7: Standard Under-Frequency Curve* The standard under-frequency curve is injected into the governor's speed input, while the generating unit is connected to the system. This will make the governor respond to the simulated under frequency event. For the purpose of calculating reserve from test results in

	this case, the following definitions apply: ▪ FIR is the additional MW output measured at 6 seconds after the start of the event (i.e. when the frequency reaches 48 Hz). ▪ SIR is the average additional MW output measured over the first 60 sec after the start of the standard under-frequency event, and sustained for at least 15 minutes after the start of the event. The test should be carried out using different machine loads (e.g. 20, 40, 60, 80% of full load) and synchronous condenser operation (if applicable), and cover the complete 60 sec period for the under-frequency event. Reserve capability may vary considerably with machine load. For the duration of the test, (at least 60 seconds) the signals to measure are: ▪ system frequency ▪ governor frequency ▪ machine MW's ▪ gate or valve position The system frequency is required as significant deviations from the nominal 50 Hz can affect results. Unless there is a real under-frequency event the system frequency should not vary by more than +/- 0.2 Hz, however this will partially depend on the amount of load the generating unit picks up during the test. Other items such as the load on other machines at the same station and turbine head / pressure levels, should be recorded at the start of each test. The proportional, integral, and derivative settings should also be recorded. These are necessary for calibration of the model. Also the reserve available can vary depending on the headwater level or steam pressure. If the head or steam pressure is likely to change significantly during the test it should be recorded for the duration of the test in addition to the signals mentioned above. The plots of MW and frequency versus time, together with the resulting FIR/SIR capability, at the various generating unit loads, are to be submitted to the System Operator as tabular electronic data, to enable the tested response to be compared with the model response. The plots should be provided in electronic form, to enable accurate calibration with the model. The criteria for acceptance of the reserve capability is: ▪ The governor has settings/parameters resulting in a stable response. This can be verified by either a simulation of a step change in load with the generating unit connected to an isolated system supplying a resistive load, or a frequency response (Nyquist) plot of the governor. ▪ The simulation of the FIR/SIR capability and response curve adequately matches the tested response.

2.3.4 Over Frequency Reserve

2.3.4.1 Definition	The provision of equipment that enables an automatic reduction in the level of injection into the power system to arrest an unplanned rise in system frequency arising form an event, the total response being fast enough and the quantity being sufficient to ensure that the frequency does not exceed defined levels.
2.3.4.2 Application	Over Frequency reserve can be provided by generators.
2.3.4.3 Purpose of test	The System Operator need to ensure the integrity of the over frequency Ancillary Service provision by issuing requirements to service providers for assessing the Reserve Capability of their assets. The reason for testing reserve capability is to allow the System operator to model and manage the total system reserve in the market. The relay equipment must be maintained in accordance with good industry practice so that it can provide over frequency reserve in accordance with the ancillary contract.
2.3.4.4 Test/ Information Requirement	The test must verify the following: ▪ The arming signal arms the equipment ▪ The equipment operates correctly for simulated required frequency ▪ Trip circuitry is correctly connected.
2.3.4.5 Testing/ Information Frequency	Testing requirements are defined in the Procurement Plan.

2.3.5 Voltage Support

2.3.5.1 Definition	Reactive power injection or absorption capability of assets and other reactive power resources provided to maintain voltage at a point of connection to the grid with the objective of avoiding cascade failure and maintaining voltage fluctuations as outlined in Part 7 Clause 7.2 subclause 1 of the 'Code'.
2.3.5.2 Application	Voltage support can be provided by both generators and grid owner equipment.
2.3.5.3 Purpose of test	The System Operator needs to ensure the integrity of the Voltage Support Ancillary Service provision by issuing requirements to service providers for assessing the Voltage Support Capability of their assets. **Generators** The required outcome of Exciter/AVR or voltage control testing is to provide the System Operator with a mathematical model which describes the steady state and dynamic behaviour of the equipment. An accurate representation allows the System Operator to model interactions with the system and other generating stations, when subjected to disturbances on the system, and thereby control the voltage stability of the system. **Static Var Compensator** The outcome of Static Var Compensator tests is to: ▪ Provide the System Operator with a mathematical model that describes the steady-state and dynamic behaviour of the SVC ▪ Confirm the expected response to disturbances Verify the integrity of the SVC control and protection systems. **Capacitor and Reactors**

Manually Controlled

The outcome of Capacitor and Reactor testing is to verify their parameters for modeling purposes.

AVR Controlled Capacitors/Reactors and Reactive Power Control

The outcome is to check the operating thresholds and time delays of the capacitor switching operation.

Synchronous Compensator

The required outcome of synchronous compensator testing is to provide the System Operator with a mathematical model that describes the equipment's steady state and dynamic behaviour.

A model of the compensator is fundamental to any dynamic stability studies as well as load flow and fault studies. The standard 2-axes model is used, which is well-documented in standards and literature.

2.3.5.4 Test/ Information Requirement

The tests must verify the following:

Generator unit exciter/ AVR and voltage control

- a block diagram showing the mathematical representation of the particular manufacturer's model of AVR and exciter installed on the generating unit or external to the unit
- a parameter list showing gains, time constants, and other settings applicable to the block diagram above
- commissioning test results consisting of step responses (isolated operation), as tabular electronic data, to verify the tuning and stability of the exciter or voltage control system.

Static Var Compensator

- A block diagram showing the mathematical model of the SVC.
- A parameter list showing the gains, time constants, limiters and other settings applicable to the above block diagram
- Detailed functional description of all the components of an SVC and how they interact in all modes of control.
- Test results from the step response tests (isolated or online operation), and the fault recovery AC disturbance response as electronic tabular data files, in order to verify the tuning and stability of the SVC.

Capacitor/Reactors

- Tabular data
- Setting records
- Functional checks

Synchronous Condenser

The synchronous condenser parameter output tests are required to produce:

- Characteristic curves – Capability diagram, open & short circuit curves, V-curve, Zero power factor curve, and Unbalanced load-time curve.
- Machine reactances.
- Machine time constants.
- Saturation data

The tests are required to produce the following in relation to exciter/AVR components of the synchronous condenser output:

- A block diagram showing the mathematical representation of the particular model of AVR and exciter installed on the synchronous condenser.
- Detailed functional description of the excitation system including all accessory functions: Load compensator, Under-excitation limiter, Over-excitation limiter, Voltage frequency limiter, P/Q limiter, Power System Stabiliser. All modes of control should also be described, e.g. voltage control, power factor control, etc.
- A parameter list showing gains, time constants, and other settings applicable to the block diagram above.
- Commissioning and test results consisting of step responses (isolated operation), as electronic data, to verify the tuning and stability of the exciter.

2.3.5.5 Testing/ Information Frequency

Testing requirements are defined in the Procurement Plan.

2.3.5.6 Tests that will achieve required outcome

2.3.5.6.1 Generator Exciter/AVR and Voltage Control Synchronous Machine Exciter Block Diagrams/Models

Item	Description
Exciter Type	There are many different types of excitation systems in use, and consequently there is a large number of possible mathematical models to describe the dynamic behaviour of an excitation system. For new equipment, the manufacturer will be able to provide a suitable model for dynamic studies together with the required parameters. These would be tested and verified (and if necessary modified) at commissioning time. Alternatively, a mathematical model can be selected on the basis of its generic type: DC, AC or ST (Static), and inspection of the schematics and other manufacturers' documentation. An appropriate model can generally be selected from the following standard types (as defined in **IEEE Std 421.5-1992**): ▪ Type DC1A – DC commutator exciter. ▪ Type DC2A – DC commutator exciter with bus fed regulator. ▪ Type DC3A – DC commutator exciter with non-continuously acting regulators. ▪ Type AC1A – Alternator-rectifier excitation system with non-controlled rectifiers and feedback from exciter field current. ▪ Type AC2A – High initial response alternator rectifier excitation system with non-controlled rectifiers and feedback from exciter field current. ▪ Type AC3A – Alternator-rectifier exciter with alternator field current limiter. ▪ Type AC4A – Alternator supplied controlled-rectifier exciter. ▪ Type AC5A – Simplified rotating rectifier excitation system. ▪ Type AC6A – Alternator-rectifier excitation system with non-controlled rectifiers and system supplied electronic voltage regulator.

	▪ Type ST1A – Potential-source controlled-rectifier exciter. ▪ Type ST2A – Compound-source rectifier exciter. ▪ Type ST3A – Potential or compound-source controlled-rectifier exciter with field voltage control loop. Additional functionality for individual manufacturers may be required. If over and under excitation limiters are fitted, appropriate block diagrams should also be provided for these components.
Settings/ Parameters	Associated with the excitation system model is a parameter list that contains the tuning settings, gains, and time constants that control the response of the excitation system. For modern excitation systems with digital AVRs, many of the required parameters can be obtained directly, or with scaling, from the settings documentation supplied by the manufacturer. For older plant which is being re-tested or which has never been tested, a trial and error approach may be needed, using parameter identification and curve fitting techniques (this has been used in the past for deriving models for generating units in the NZ system). The parameters can be verified by comparing simulated responses with tested results. Tests that can be carried out are: ▪ Terminal voltage step response tests (with the machine running at no-load isolated from the system). ▪ Frequency response tests (both isolated and connected to the grid). ▪ Mvar load rejection tests (high leading Mvar, and high lagging Mvar).
Exciter Stability	The System Operator criteria for testing the stability of the model is to model the generating unit and exciter isolated from the system and to apply a step change to the exciter's voltage reference. The transient response of the generating unit terminal voltage should be stable and well damped. Figure 3 of **IEEE Std 421.2-1990** shows the classical ideal control system response with 1.5 cycles to reach settling band and approximately 15% overshoot on the first oscillation. The response can be verified with a tested result. Other methods that can be performed (by test or simulation) to verify the stability of the excitation system are: ▪ Open loop frequency response Bode plots (used to obtain the gain and phase margins). Gain margin should typically be 6 dB or more, and phase margin should typically be 40° or more. ▪ Closed loop frequency response Bode plots (used to obtain the peak amplitude response and the bandwidth).
Relevant	**IEEE Std 421.2-1990**: IEEE Guide for Identification,

Standards	Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. **IEEE Std 421.5-1992**: IEEE Recommended Practice for Excitation System Models for Power System Stability Studies. **IEC60034-16-1-1991**: Rotating Electrical Machines - Excitation Systems for Synchronous Machines – Chapter 1, Definitions.

2.3.5.6.2 Generator Exciter/AVR and Voltage Control Asynchronous Machine Voltage Control Block Diagrams/ Models

Item	Description
Functional Description and Block Diagram	Reactive Power consumption/production for induction machines can be achieved by either reactive power setpoint or power factor setpoint. The block diagram of the type of control is usually supplied by the manufacturer. If power factor setpoint is used, the adjustment of the setpoint according to the grid voltage level should be described.
Settings/ Parameters	Mode of control proposed should be clearly stated. For adjustable parameters, the range, deadband and rate should be stated and proposed settings supplied.
Reactive Power Compensation	Total reactive power (Mvar) of the compensation capacitor bank and step size for each step or number of steps and capacitor size (Mvar) for uniform steps should be supplied from the manufacturer's information.
Relevant Standards	**IEEE Std 112-1996**: IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.

2.3.5.6.3 Static Var Compensators

Item	Description
General	This section details the basic technical requirements for the Grid Owner with respect to SVC equipment.
Tests	The manufacturer or commissioning test reports should be able to supply suitable models together with the required parameters. Otherwise, physical testing will be needed to identify the required models and parameters. Routine tests are required as follows: ▪ Steady State and Dynamic Stability step response (isolated or online operation) ▪ AC disturbance performance (fault recovery) SVC equipment integrity checks should be done by performing primary and/or secondary injections for verifying the following:

	▪ Input signals ▪ Controls, protection and indications correct output **Note**: All SVC tests are to be performed to international standards.
Relevant Standards	**IEEE Std 1031-2000** (01-May-2000), IEEE Guide for the Functional Specification of Transmission Static Var Compensators **IEC Std 61954** (27-Mar-2003) Power electronics for electrical transmission and distribution systems - Testing of thyristor valves for static VAR compensators

2.3.5.6.4 Capacitors/Reactors

Item	Description
General	This section details the basic technical requirements for the Grid Owner tests with respect to capacitors and reactors.
Tests	Tests undertaken at commissioning or are part of factory testing include: ▪ Capacitance measurement ▪ Impedance measurement ▪ DC winding resistance These tests will be undertaken according to **IEC 60871-1** for capacitors and **IEC 60289** for reactors. Tests undertaken for capacitors or capacitor/filter banks as part of routine maintenance include: ▪ Capacitance measurement Tests undertaken for automatic voltage regulation schemes such as automatic capacitor switching, Reactive Power Control (RPC) or DC control winding reactance include: ▪ Operating threshold ▪ Time delay If information is not available from the manufacturer or commissioning then physical testing will be required.
Relevant Standards	**IEC 60871-1** (17-Oct-1997), Shunt capacitors for a.c. power systems having a rated voltage above 1000 V - Part 1: General performance, testing and rating - Safety requirements - Guide for installation and operation **IEC 60289** (15-May-1988) Reactors

2.3.6 Black Start

2.3.6.1 Definition	Equipment that is made available to enable generation units isolated from a grid to be livened and connected to the grid, ready and then able to live the grid at that grid injection point without any power being obtained from the grid.
2.3.6.2 Application	Black Start is provided by generators.
2.3.6.3 Purpose of test	Transpower must be able to demonstrate the ability to recover from a total or partial shutdown of the transmission system. The black start capability is necessary to ensure the reliable operation of the national grid. The black start test is to improve black start processes for all parties involved and provide a framework for managing future tests.
2.3.6.4 Test/ Information Requirement	The key objectives of the test are: ▪ Demonstrate the processes, systems and plant used for restoring supply are fit for the purpose of delivering the service. ▪ Increase awareness and understanding in Black Start ▪ To enhance the capability to manage a Black Start event ▪ To enhance the capability to recover from a Black Start event.
2.3.6.5 Testing/ Information Frequency	Testing requirements are defined in the Procurement Plan of the 'Code'. The following technical abilities need to be demonstrated during the testing: ▪ The ability to start up the main generating of the power station from shutdown in agreed timescales without the use of external power supplies; ▪ The capability to energise part of the transmission grid system within agreed timescales following of instruction from Transpower. ▪ The capability to accept instantaneous loading of demand blocks and controlling frequency and voltage levels within acceptable limits during the block loading process (under these conditions, frequency will be within the range 47 to 52 Hz); ▪ The reactive capability to charge the immediate transmission grid system. This capability will depend on the test system configuration.
2.3.6.6 Baseline Tests	Each item of black start equipment is tested to prove that they can start without power being obtained from the grid.

3 Grid Owner Tests

3.1 Routine Testing

3.1.1 Overview

3.1.1.1 Content

Part III outlines the routine grid owner tests required to verify the steady-state and dynamic performance of:

- Transformers
- Static Var Compensator(s) (SVC)
- HVDC
- Capacitors/Reactors
- Synchronous Compensators
- AUFLS equipment (for South Island GXPs)

3.1.1.2 Structure

This part consists of the following sections:

3.1.2 Transformer Voltage Range

3.1.2.1 Content

This section sets out the test requirements to confirm grid owner transformer voltage range

3.1.2.2 Application

This section applies to the grid owner

3.1.2.3 Purpose of test

The primary purpose of obtaining transformer data is to assess the ability of transformer units to maintain point of supply voltage and reactive power capability within the applicable limits.

3.1.2.4 Test outcome

The test will verify the control system operation of on-load tap changers at a controlled node of the grid including:

- voltage setpoints
- operating deadbands
- response times.

3.1.2.5 ACS Reference

This information is required in section 2.0 and 3.0 of the ACS

3.1.2.6 Test that will achieve required outcome

3.1.2.6.1 Transformer Unit and Tap Changer

Item	Description
Tap Changers	The Voltage regulating relays of on-load tap changers are to be verified by: ▪ injection testing; or ▪ according to the individual asset owner's standard equipment test procedures.

3.1.3 Reactive Capability –SVC Transient Response, Control, and Protection

3.1.3.1 Content

This section details the basic technical requirements for the grid owner with respect to SVC equipment.

3.1.3.2 Application

This section applies to the grid owner for all SVC equipment.

3.1.3.3 Purpose of test

The purpose of SVC tests is to:

- provide a mathematical model that describes the steady-state and dynamic behaviour of the SVC
- allow the SVC interaction with the system when subjected to disturbances in the system to be modelled. This will assist voltage stability
- verify the integrity of the SVC control and protection systems.

3.1.3.4 Test outcome

The test/information requirements of the SVC output are:

- a block diagram showing the mathematical model of the SVC
- a parameter list showing the gains, time constants, limiters, and other settings applicable to the above block diagram
- a detailed functional description of all the components of an SVC and how they interact in all modes of control
- test results from the step response tests (isolated or online operation), and the fault recovery AC disturbance response as electronic tabular data files, to verify the tuning and stability of the SVC.

3.1.3.5 ACS Reference

This information is required in section 9.0 of the ACS.

3.1.3.6 Test that will achieve required outcome

3.1.3.6.1 Static Var Compensators

Item	Description
Routine Tests	Routine tests are required as follows: ▪ Steady State and Dynamic Stability step response (isolated or online operation) ▪ AC disturbance performance (fault recovery) SVC equipment integrity checks should be done by performing primary and/or secondary injections for verifying the following: ▪ Input signals ▪ Controls, protection, and indications correct output All SVC tests are to be performed to international standards. **IEEE Std 1031-2000** (01-May-2000), IEEE Guide for the Functional Specification of Transmission Static Var Compensators

	IEC Std 61954 (27-Mar-2003) Power electronics for electrical transmission and distribution systems - Testing of thyristor valves for static VAR compensators

3.1.4 Capacitor and Reactive Power Control Systems

3.1.4.1 Content

This section details the basic technical requirements for the grid owner tests with respect to capacitors, reactors and reactive power control systems.

3.1.4.2 Application

This section applies to the capacitors, reactors and reactive power control systems owned by the grid owner

3.1.4.3 Purpose of test

The tests with respect to capacitors and reactors are required for the purpose of:

- verifying the parameters of capacitors for modelling purposes
- checking the operating thresholds and time delays of the capacitor switching operation of AVR controlled capacitors, reactors and reactive power controllers.

3.1.4.4 Test outcome

The testing is required to produce:

- Tabular data
- Setting records
- Functional checks

3.1.4.5 ACS Reference

This information is required in section 8.0 of the ACS.

3.1.4.6 Test that will achieve required outcome

3.1.4.6.1 Capacitors and Reactors

Item	Description
Tests	Tests undertaken for capacitors or capacitor/filter banks as part of routine maintenance include: ▪ Capacitance measurement Tests undertaken for automatic voltage regulation schemes such as automatic capacitor switching, Reactive Power Control (RPC) or DC control winding reactance include: ▪ Operating threshold ▪ Time delay If information is not available from the manufacturer or commissioning then physical testing will be required
Relevant Standards	**IEC 60871-1** (17-Oct-1997), Shunt capacitors for a.c. power systems having a rated voltage above 1000 V - Part 1: General performance, testing and rating - Safety requirements - Guide for installation and operation **IEC 60289** (15-May-1988) Reactors

3.1.5 Synchronous Compensators AVR/Exciter Systems

3.1.5.1 Content

This section details the basic technical requirements for the grid owner tests with respect to synchronous compensators.

3.1.5.2 Application

This section applies to synchronous compensators owned by the grid owner.

3.1.5.3 Purpose of test

The testing is required for the purpose of providing a mathematical model that describes the equipment's steady state and dynamic behaviour.

A model of the compensator is fundamental to any dynamic stability studies as well as load flow and fault studies. The standard 2-axes model is used, which is well-documented in standards and literature.

3.1.5.4 Test outcome

The tests related to the exciter/AVR components of the synchronous condenser output are required to produce:

- a block diagram showing the mathematical representation of the particular model of AVR and exciter installed on the synchronous condenser
- a detailed functional description of the excitation system including all accessory functions: Load compensator, Under-excitation limiter, Over-excitation limiter, Voltage frequency limiter, P/Q limiter, Power System Stabiliser. All modes of control should also be described, e.g. voltage control, power factor control, etc
- a parameter list showing gains, time constants, and other settings applicable to the block diagram above
- test results consisting of step responses (isolated operation), as electronic data, to verify the tuning and stability of the exciter.

3.1.5.5 ACS Reference

This information is required in section10.0 of the ACS.

3.1.5.6 Test that will achieve required outcome

3.1.5.6.1 Synchronous Compensators

Item	Description
Excitation System Tests	**<u>Exciter parameters</u>** Exciter parameters include transfer function, limiter settings, saturation factors, time constants, regulator gain etc. These parameters are checked during commissioning and again with excitation system replacement using either factory tests and/or computer simulation. IEEE 421.2-1990 is used as a standard. Tests carried out at commissioning and during excitation system replacement include: ▪ Step response tests ▪ Voltage ramping tests. ▪ IEEE 421.5-1992 is used as a standard.

Exciter Stability	The system operator criteria for testing the stability of the model are to model the synchronous compensator and exciter isolated from the system and to apply a step change to the exciter's voltage reference. The transient response of the synchronous compensator's terminal voltage should be stable and well damped. Figure 3 of **IEEE Std 421.2-1990** shows the classical ideal control system response with 1.5 cycles to reach settling band and approximately 15% overshoot on the first oscillation. The response can be verified with a tested result. Other methods that can be performed (by test or simulation) to verify the stability of the excitation system are: ▪ open loop frequency response Bode plots (used to obtain the gain and phase margins). Gain margin should typically be 6 dB or more, and phase margin should typically be 40° or more ▪ closed loop frequency response Bode plots (used to obtain the peak amplitude response and the bandwidth)
Relevant Standards	**IEC 60034-4** (01-Jan-1985), Rotating electrical machines. Part 4: Methods for determining synchronous machine quantities from tests. **IEC 60034-4 Amd 1** (26-Apr-1995), Amendment 1 - Rotating electrical machines. Part 4: Methods for determining synchronous machine quantities from tests. **IEEE Std 421.2-1990**: IEEE Guide for Identification, Testing, and Evaluation of the Dynamic Performance of Excitation Control Systems. **IEEE Std 421.5-1992**: IEEE Recommended Practice for Excitation System Models for Power System Stability Studies.

3.1.6 HVDC Link Frequency Control and Protection

3.1.6.1 Content

This section details the basic technical requirements for the grid owner tests with respect to HVDC equipment.

3.1.6.2 Application

This section applies to the HVDC equipment owned by the HVDC owner.

3.1.6.3 Purpose of test

Tests on critical aspects of the HVDC are required for the purpose of ensuring the behaviour of the link can be accurately modelled. Therefore, HVDC tests are required to:

- provide a control system model that reflects the behaviour of the link in all possible operating conditions
- verify control functionality of main modulations
- verify the integrity of primary plant control and protection systems.

3.1.6.4 Test outcome

The HVDC control testing will be required to produce:

- a block diagram showing the basic mathematical model of the HVDC
- a parameter list showing the gains, time constants, limiters and other settings applicable to the above block diagram
- a detailed functional description of all the main components of the HVDC and

how they interact in all modes of control

- results from offline or online testing (wherever possible) of the HVDC for all the main modulation functions it performs.

3.1.6.5 ACS Reference

This information is required in section 21.0 of the ACS.

3.1.6.6 Test that will achieve required outcome

3.1.6.6.1 HVDC

Item	Description
HVDC Modulation Tests	Routine tests (as the grid operation permits) or as required by the system operator are: ▪ HVDC modulation tests ▪ Voltage stabilisation dynamic performance ▪ Staged faults ▪ Frequency stabiliser and spinning reserve sharing 250 MW North Island and 100 MW South Island generation trips Tests will be undertaken following CIGRE and/or the manufacturer's recommendations. Refer to: "System tests for HVDC Installations." (WG 14.12), **CIGRE Ref. No 97** "Operational guidelines and monitoring of HVDC systems." (WG 14.23), **CIGRE Ref. No. 130**
HVDC Equipment Tests	Integrity equipment integrity checks should be done by performing primary and/or secondary injections for verifying the following: ▪ Analogue and Digital Input/Output signals ▪ Control sequences and closed loop controls. ▪ Protection Systems **IEEE Standard 1378-1997**, IEEE Guide for Commissioning HVDC Converter Stations and Associated Transmission Systems

3.1.7 AUFLS Profiles and Trip Settings (South Island GXPs only)

3.1.7.1 Content

This section sets out the test requirements for AUFLS equipment for South Island GXPs.

3.1.7.2 Application

This section applies to the grid owner, who is responsible for providing AUFLS equipment for South Island GXPs.

3.1.7.3 Purpose of test

AUFLS are a critical factor in the system operator's assessment of reserve requirements to prevent cascade failure of the power system.

Tests are therefore required to confirm:

- the AUFLS profiles provided in the ACS
- the trip settings and reliability of the relays.

3.1.7.4 Test outcome

The tests are required to ensure the rules relating to AUFLS are met, demonstrated by:

- profile data[1] provided by the grid owner as part of their ACS; and
- test results of the AUFLS relay functionality.

3.1.7.5 ACS Reference

The information is required in section 23.0 of the ACS.

3.1.7.6 Test that will achieve required outcome

3.1.7.6.1 Automatic Under Frequency Load Shedding (AUFLS)

Item	Description
Tests	A series of tests are conducted on feeders using measured SCADA and metering data to confirm trip settings for AUFLS to operate. Tests for frequency are based on the standard protection relay recommended tests and should meet the following: ▪ Meet the tolerances (frequency trip levels and time delays) set out in Part 8, Scdule 8.3, Technical Code B, Clause 6 of the 'Code'.. ▪ A frequency generator that is capable of ramping down from just above set frequency to just below set frequency should be used. ▪ Frequency measurement having an accuracy of ± 0.01 Hz over the frequency range of 40 to 60 Hz. ▪ Time resolution of ±10 msec. ▪ Under-frequency relay time delay should be included in total operation time from when the frequency drops below the specified threshold until the load shedding contacts are energised

3.1.8 Protection Systems

3.1.8.1 Content

This section describes the minimum recommended routine testing for general grid owner protection assets not already covered by previous requirements.

3.1.8.2 Application

This section applies to the grid owner's assets at the grid interface.

3.1.8.3 Purpose of test

The effectiveness and co-ordination of asset owner protection systems are fundamental to the System Operator's ability to plan to comply and comply with the PPOs.

Testing of the protection system demonstrates grid owner compliance with Part 8, clause 8.25, subclause 1 of Part 8 and Schedule 8.3, Technical Code A, clause 4 and provides the system operator and other asset owners with assurance that asset owners are co-operating to ensure protection is co-ordinated across the grid interface.

3.1.8.4 Test outcome

Testing of protection systems is required to confirm:

- protection is co-ordinated across the grid interface
- accuracy of primary circuit parameters and integrity of the tripping circuit components at the grid interface
- protection settings are properly identified, applied and checked to meet the outcomes set out in the 'Code'

[1] The percentage of total pre-event demand for two blocks of demand is required as per the Part 8, Schedule 8.3, Technical Code B, clause 7, subclause 6 of the 'Code'. The profile information required by the ACS takes into account the variability of the data according to time of day/season. Where Distributors are uncertain of the exact nature of the load, they should ensure that enough load can be shed at all times to meet the EGR requirements.

- protection is coordinated with other asset owners at the grid interface
- protection remains coordinated, with other asset owners at the grid interface, after any modification and change at the grid interface

3.1.8.5 ACS Reference

The information is required in section 13.0 of the ACS as a series of confirming questions (i.e. yes or no answers are only required).

3.1.8.6 Test that will achieve required outcome

3.1.8.6.1 Protection Systems

Item	Description
Initial Protection Audit	Asset owners (either individually or collectively) who have not actively confirmed protection is co-ordinated should undertake an initial 'one-off' review of protection system co-ordination across the grid interface to ensure existing protection: ▪ is adequate ▪ meets the requirement for co-ordination at the grid interface. Such review should be carried out by an appropriately qualified independent expert.
Routine protection systems audit	For asset owners to meet the AOPOs and technical codes in relation to protection each will need an effective management system to ensure the Test Outcomes set out above. . A means of ensuring the protection remains co-ordinated on an ongoing basis is for asset owners at the grid interface (individually or collectively) to engage an independent and suitably qualified person to audit the management system for protection of assets. Such audit should be conducted every 4-5 years and confirm there are effective systems in place to meet and maintain the 'Code' requirements for protection systems.
Relay tests	Relay tests should be carried out to the individual asset owner's standard equipment test procedures.

3.2 Initial Tests Commissioning/Modification

3.2.1 Overview

3.2.1.1 Content

This section outlines the grid owner tests required to provide sufficient information to verify the steady-state and dynamic performance of the following:

- Transformers
- Transmission lines
- Static Var Compensator(s) (SVC)
- HVDC
- Capacitors/Reactors
- Synchronous Compensators
- AUFLS equipment (for South Island GXPs)

Some of the tests detailed in this section repeat those required for routine tests. (Section 3.1 Grid Owner Tests: Routine Testing) They are included here to make this a complete and stand alone section for commissioning and modification tests.

3.2.1.2 Structure

This part consists of the following sections:

3.2.2 Transformers

3.2.2.1 Content

This section details the basic technical requirements for the grid owner for transformer testing.

3.2.2.2 Application

This section applies to the transformers owned by the grid owner.

3.2.2.3 Purpose of test

Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset.

3.2.2.4 Test outcome

The primary outcome of obtaining transformer data is to assess the ability of transformer units to maintain point of supply voltage and reactive power capability within the applicable limits.

3.2.2.5 ACS Reference

The test is required to produce information about the transformers for the relevant sections of the grid owner ACS.

3.2.2.6 Tests that will achieve required outcome

3.2.2.6.1 Transformer Unit and Tap Changer

Item	Description
General Information	The following parameters are all available from the transformer nameplate: ▪ HV/MV/LV Voltages ▪ Bushing Nominal, Emergency Overload and Fault Ratings ▪ Number of windings per phase ▪ Vector Group ▪ Rating HV/LV (2-winding transformers) Rating HV/MV/LV (3-winding transformers). The remaining information shown below will be available from manufacturer's documentation and test reports. ▪ Core Losses ▪ Magnetising Current ▪ B-H Curve ▪ Construction Type
Impedances	The following parameters should all be available from the manufacturer and commissioning test reports. The values should all be referenced to the high voltage side MVA base. ▪ Positive Sequence Impedance Data (2 and 3 wdg transformers) ▪ Zero Sequence Impedance Data (2 wdg and 3 wdg transformers) If the transformer has never been tested or the records are unavailable, the transformer will require testing (using the standard transformer test methods) to determine these values.
Tap Changers	The minimum/maximum tap positions are: ▪ Voltage at tap number The nominal tap position is: ▪ For off-load tap changers, the actual voltage and the tap number. ▪ For on-load tap changers, the nominal voltage and the tap number. The type is either: ▪ On-load ▪ Off-load ▪ Fixed The tap step is the % change of nominal voltage per step. The tap size is the voltage per step. Controlled node data is the mode, voltage setpoint, upper and lower voltage deadbands and setting response time particular to that node. **Note** that the numbering sequence assumed is that the lowest tap number corresponds to the lowest voltage (ratio). If the sequence is reversed it should be clearly

	stated. All the parameters can all be determined by inspection of nameplate or obtained from manufacturer or commissioning test reports. If information is not available from the manufacturer or commissioning then physical testing will be required. Voltage regulating relays of on-load tap changers are required to be routinely tested for grid-connected transformers to verify the following: ▪ Voltage setpoint ▪ Operating deadbands ▪ Response time

3.2.3 Transmission Lines

3.2.3.1 Content	This section details the basic technical requirements for transmission lines testing.
3.2.3.2 Application	This section applies to transmission lines owned by the grid owner.
3.2.3.3 Purpose of test	Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset. Electrical parameters may be determined from manufacturer's data, the asset owner's calculations, simulations and commissioning test data. The system operator may require that a physical test be conducted to determine the capacitance of a line.
3.2.3.4 Test outcome	The primary outcome of obtaining transmission line data is to enable the system operator to maintain system security, particularly with respect to security planning and offload times.
3.2.3.5 ACS Reference	The test/information requirements for transmission lines are as per the relevant section of the grid owner ACS.
3.2.3.6 Tests that will achieve required outcome	**3.2.3.6.1 Transmission Line**

Item	Description
General	This section details the basic technical requirements for the grid owner with respect to Transmission Lines

Tests	The manufacturer or commissioning test reports should be able to supply suitable models together with the required parameters. Data supplied for modelling purposes by the manufacturer can be summarised in the following categories: ▪ Current-carrying conductor details (type, ground resistance, section length, etc.) ▪ Earth wire conductor details (type, number of, length) ▪ Cable Data (cross-sectional area, current rating, etc.) ▪ +ve and –ve sequence data (reactance, resistance, susceptance, conductance) ▪ Zero sequence data (reactance, resistance, susceptance, conductance) Possible tests could be conducted for measuring the capacitance of the line by energising the line from one end and measuring CT secondary current and bus VT secondary voltage at the other end. All tests are to be performed to international standards.
Relevant Standards	IEEE Standards Engineering in Safety, Maintenance and Operation of Lines Collection (ESMOL) - 1993 Edition (9 standards and guides)

3.2.4 SVCs

3.2.4.1 Content

This section details the basic technical requirements for the grid owner with respect to SVC equipment

3.2.4.2 Application

This section applies to SVC's owned by the grid owner.

3.2.4.3 Purpose of test

Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset.

3.2.4.4 Test outcome

SVC tests are to :

- Provide the system operator with a mathematical model that describes the steady-state and dynamic behaviour of the SVC
- Confirm the expected response to disturbances
- Verify the integrity of the SVC control and protection systems.

3.2.4.5 ACS Reference

The SVC tests are required to result in:

- A block diagram showing the mathematical model of the SVC.
- A parameter list showing the gains, time constants, limiters and other settings applicable to the above block diagram
- Detailed functional description of all the components of an SVC and how they interact in all modes of control.
- Test results from the step response tests (isolated or online operation), and the fault recovery AC disturbance response as electronic tabular data files, in order to verify the tuning and stability of the SVC.

3.2.4.6 Tests that will achieve required outcome

3.2.4.6.1 Static Var Compensators

Item	Description
Tests	The manufacturer or commissioning test reports should be able to supply suitable models together with the required parameters. Otherwise, physical testing will be needed to identify the required models and parameters. SVC equipment integrity checks should be done by performing primary and/or secondary injections for verifying the following: ▪ Input signals ▪ Controls, protection and indications correct output All SVC tests are to be performed to international standards.
Relevant Standards	**IEEE Std 1031-2000** (01-May-2000), IEEE Guide for the Functional Specification of Transmission Static Var Compensators **IEC Std 61954** (27-Mar-2003) Power electronics for electrical transmission and distribution systems - Testing of thyristor valves for SVCs

3.2.5 HVDC

3.2.5.1 Content

This section details the basic technical requirements for the grid owner with respect to HVDC equipment

3.2.5.2 Application

This section applies to the HVDC equipment owned by the HVDC owner.

3.2.5.3 Purpose of test

Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset.

3.2.5.4 Test outcome

Because of its potential impact on system stability, HVDC tests are required to provide the system operator with a high degree of confidence in the following:

- A control system model that reflects the behaviour of the link in all possible operating conditions.
- Verification of control functionality of main modulations
- Verification of the integrity of primary plant control and protection systems.

3.2.5.5 ACS Reference

The HVDC control testing is required to produce:

- a block diagram showing the basic mathematical model of the HVDC
- a parameter list showing the gains, time constants, limiters and other settings applicable to the above block diagram
- detailed functional description of all the main components of the HVDC and how they interact in all modes of control
- results from offline or online testing (wherever possible) of the HVDC for all the main modulation functions it performs.

3.2.5.6 Tests that will achieve required outcome

3.2.5.6.1 HVDC

Item	Description
Tests	**HVDC** Tests expected to be undertaken at commissioning are: ▪ Steady state transmission tests ▪ AC and DC staged faults to verify overall system behaviour ▪ Runback tests ▪ Load rejection tests at 300 MW. ▪ Steady state with modulations on ▪ High power pole trips (to verify power transfer to other pole) ▪ AC system over voltage and frequency fluctuations ▪ Steady state and dynamic stability tests (current step response, power ramping) Tests will be undertaken following CIGRE and/or the manufacturer's recommendations. **HVDC Equipment** Integrity equipment integrity checks should be done by performing primary and/or secondary injections for verifying the following: ▪ Analogue and Digital Input/Output signals ▪ Control sequences and closed loop controls. ▪ Protection Systems
Relevant Standards	**IEEE Standard 1378-1997**, IEEE Guide for Commissioning HVDC Converter Stations and Associated Transmission Systems.

3.2.6 Capacitors/Reactors

3.2.6.1 Content

This section details the basic technical requirements for the grid owner with respect to capacitors and reactors

3.2.6.2 Application

This section applies to the capacitors and reactors owned by the grid owner.

3.2.6.3 Purpose of test

Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset.

3.2.6.4 Test outcome

Manually Controlled

The purpose of Capacitor and Reactor testing is to verify their parameters for modelling purposes.

AVR Controlled Capacitors/Reactors and Reactive Power Control

The purpose is to check the operating thresholds and time delays of the capacitor switching operation.

3.2.6.5 ACS Reference

The tests are required to produce:

- Tabular data
- Setting records
- Functional checks

3.2.6.6 Tests that will achieve required outcome

3.2.6.6.1 Capacitors and Reactors

Item	Description
Tests	Capacitors/Reactors Tests undertaken at commissioning or are part of factory testing include: ▪ Capacitance measurement ▪ Impedance measurement ▪ DC winding resistance These tests will be undertaken according to **IEC 60871-1** for capacitors and **IEC 60289** for reactors. Tests undertaken for automatic voltage regulation schemes such as automatic capacitor switching, Reactive Power Control (RPC) or DC control winding reactance include: ▪ Operating threshold ▪ Time delay If information is not available from the manufacturer or commissioning then physical testing will be required.
Relevant Standards	**IEC 60871-1** (17-Oct-1997), Shunt capacitors for a.c. power systems having a rated voltage above 1000 V - Part 1: General performance, testing and rating - Safety requirements - Guide for installation and operation **IEC 60289** (15-May-1988) Reactors

3.2.7 Synchronous Compensators

3.2.7.1 Content

This section details the basic technical requirements for the grid owner tests with respect to synchronous compensators

3.2.7.2 Application

This section applies to the synchronous condensers owned by the grid owner. Data to be provided by way of ACS when asset is first built or when changes are made which affect the electrical characteristics of the asset.

3.2.7.3 Purpose of test

Synchronous compensator testing is required to provide a mathematical model that describes the equipment's steady state and dynamic behaviour.

A model of the compensator is fundamental to any dynamic stability studies as well as load flow and fault studies. The standard 2-axes model is used, which is well-documented in standards and literature.

3.2.7.4 Test outcome

i. The synchronous condenser parameter output tests are required to produce:

- Characteristic curves – Capability diagram, open & short circuit curves, V-curve, Zero power factor curve, and Unbalanced load-time curve.
- Machine reactances.
- Machine time constants.
- Saturation data

ii. The tests are required to produce the following in relation to exciter/AVR components of the synchronous condenser output:

- A block diagram showing the mathematical representation of the particular model of AVR and exciter installed on the synchronous condenser.
- Detailed functional description of the excitation system including all accessory functions: Load compensator, Under-excitation limiter, Over-excitation limiter, Voltage frequency limiter, P/Q limiter, Power System Stabiliser. All modes of control should also be described, e.g. voltage control, power factor control, etc.
- A parameter list showing gains, time constants, and other settings applicable to the block diagram above.

Commissioning and test results consisting of step responses (isolated operation), as electronic data, to verify the tuning and stability of the exciter.

3.2.7.5 ACS Reference

This information is required in section 10.0 of the ACS

3.2.7.6 Tests that will achieve required outcome

3.2.7.6.1 Synchronous Compensators

Item	Description
Machine Tests	**<u>Reactive Power capability</u>** ▪ Heat run test at full reactive power output This test will be undertaken according to the contract specification Transpower has with the relevant customer.
	<u>M/c Reactances</u> For M/c reactances factory tests undertaken will be ▪ Open circuit and short circuit tests This test will be undertaken according to **IEC 60034-4.** **<u>M/c Time constants</u>** For M/c time constants, factory tests undertaken will be: ▪ Open circuit and short circuit tests ▪ Rotor and stator resistance measurement These tests will be undertaken according to **IEC 60034-4.** **<u>Characteristic curves</u>** Characteristic curves include the following: ▪ Open circuit curve ▪ Short circuit curve ▪ V-curve ▪ Zero power factor curve ▪ Unbalanced load-time curve Tests required are open circuit and short circuit tests.

Excitation System Tests	**Exciter parameters** Exciter parameters include transfer function, limiter settings, saturation factors, time constants, regulator gain etc. These parameters are checked during commissioning and again with excitation system replacement using either factory tests and/or computer simulation. **IEEE 421.2-1990** is used as a standard. Tests carried out at commissioning and during excitation system replacement include: ▪ Step response tests ▪ Voltage ramping tests. **IEEE 421.5-1992** is used as a standard.
Exciter Stability	The system operator criterion for testing the stability of the model is to model the synchronous compensator and exciter isolated from the system and to apply a step change to the exciter's voltage reference. The transient response of the synchronous compensator's terminal voltage should be stable and well damped. Figure 3 of **IEEE Std 421.2-1990** shows the classical ideal control system response with 1.5 cycles to reach settling band and approximately 15% overshoot on the first oscillation. The response can be verified with a tested result. Other methods that can be performed (by test or simulation) to verify the stability of the excitation system are: ▪ Open loop frequency response Bode plots (used to obtain the gain and phase margins). Gain margin should typically be 6 dB or more, and phase margin should typically be 40° or more. ▪ Closed loop frequency response Bode plots (used to obtain the peak amplitude response and the bandwidth).

3.2.8 AUFLS

3.2.8.1 Content	This section details the basic technical requirements for the AUFLS equipment for which the grid owner is responsible.
3.2.8.2 Application	This section applies to the grid owner, who is responsible for providing AUFLS equipment for South Island GXPs. Testing is required after commissioning or modification of AUFLS equipment.
3.2.8.3 Purpose of Test	AUFLS is critical for assisting the system operator to manage and provide sufficient reserve to ensure security of the system.
3.2.8.4 Test outcome	To maintain security of the power system during under frequency events, by avoiding cascade failure, the system operator requires: ▪ profile data[2]; and

[2] The percentage of total pre-event demand for two blocks of demand is required by the Part 8, Schedule 8.3, Technical Code B, clause 6. The profile information required by the ACS takes into account the variability of the data according to time of day/season

- testing of the AUFLS relay functionality.

3.2.8.5 ACS Reference

This information is required in section 23.0 of the ACS

3.2.8.6 Tests that will achieve required outcome

3.2.8.6.1 Automatic Under Frequency Load Shedding (AUFLS)

Item	Description
Tests	Tests for frequency are based on the standard protection relay recommended tests. It should meet the following minimum requirements ▪ the tolerances (frequency trip levels and time delays) set out in Part 8 Schedule 8.3 Technical Code B clause 6 of the 'Code'. ▪ A frequency generator that is capable of ramping down from just above set frequency to just below set frequency should be used. ▪ a frequency measurement accuracy of ± 0.01 Hz over the frequency range of 40 to 60 Hz ▪ a time resolution of ±10 msec ▪ an under-frequency relay time delay included in total operation time from when the frequency drops below the specified threshold until the load□shedding contacts are energised.

3.2.9 Protection

3.2.9.1 Content

This section describes the minimum recommended routine testing for distributor protection assets.

Note that the System Operator does not require Asset Owners to submit protection test data. Instead, the purpose of this section is to recommend a minimum routine testing regime to ensure that the ACS assurances with regard to the compliance of protection systems with the 'Code' can be reasonably given by the Asset Owner.

3.2.9.2 Application

This section applies to distributor protection systems. Co-ordination across the grid interface must be checked and confirmed for new or modified assets.

3.2.9.3 Purpose of test

Verification of the assurance given in the Asset Owner ACS with regard to protection assets being compliant with the 'Code'.

3.2.9.4 Test outcome

Asset owners must confirm protection is co-ordinated across the grid interface for new or modified assets.

3.2.9.5 ACS Reference

Nil

3.2.9.6 Tests that will achieve required outcome

One way of testing protection co-ordination has been achieved is for asset owners (either individually or collectively) to perform an initial review of protection system co-ordination across the grid interface to ensure existing protection:

- is adequate
- meets the requirement for co-ordination at the grid interface.

4 Distributor Tests

4.1 Routine Testing

4.1.1 Overview

4.1.1.1 Content

This part describes the routine tests that distributors are required to undertake on their assets.

4.1.1.2 Structure

This part consists of the following sections:

4.1.2 AUFLS Profiles and Trip Settings.

4.1.2.1 Content

This section describes the tests that distributors are required to undertake to confirm functionality and compliance of AUFLS.

4.1.2.2 Application

This section applies to all Distributors who are required to maintain AUFLS.

4.1.2.3 Purpose of test

AUFLS are a critical factor in the system operator’s assessment of reserve requirements to prevent cascade failure of the power system.

Tests are therefore required to confirm:

- the AUFLS profiles provided in the ACS
- the trip settings and reliability of the relays.

4.1.2.4 Test outcomes

The tests are required to ensure the rules relating to AUFLS are met, demonstrated by:

- profile data[3] provided by Distributors as part of their ACS; and
- test results of the AUFLS relay functionality

Distributors should discuss relay and load information with the grid owner where the grid owner has been involved in relay allocation.

4.1.2.5 ACS Reference

The information is required in section 4.0 of the ACS

4.1.2.6 Tests that will achieve required outcome

4.1.2.6.1 Automatic Under Frequency Load Shedding (AUFLS)

Item	Description
Tests	A series of tests are conducted on feeders using measured SCADA and metering data to confirm trip settings for AUFLS to operate. Tests for frequency are based on the standard protection relay recommended tests and should meet the following: ▪ the system should meet the tolerances (frequency trip levels and time delays) set out in Part 8 Schedule 8.3, Technical Code B, clause 6. ▪ a frequency generator that is capable of ramping down from just above set frequency to just below set frequency should be used.

[3] The percentage of total pre-event demand for two blocks of demand is required as per the Part 8, Schedule 8.3, Technical Code B, clause 7, subclause 6 of the ‘Code’. The profile information required by the ACS takes into account the variability of the data according to time of day/season. Where Distributors are uncertain of the exact nature of the load, they should ensure that enough load can be shed at all times to meet the EGR requirements.

	▪ frequency measurement should have an accuracy of ± 0.01 Hz over the frequency range of 40 to 60 Hz. ▪ the time resolution should be ±10 msec. ▪ the under-frequency relay time delay should be included in total operation time from when the frequency drops below the specified threshold until ▪ the load shedding contacts are energised.

4.1.3 Protection Systems

4.1.3.1 Content

This section describes the minimum recommended routine testing for distributor protection assets not already covered by previous requirements.

4.1.3.2 Application

This section applies to the distributor's assets at the grid interface

4.1.3.3 Purpose of test

The effectiveness and co-ordination of asset owner protection systems are fundamental to the System Operator's ability to plan to comply and comply with the PPOs.

Testing of the protection system demonstrates grid owner compliance with Part 8, Schedule 8.3, clause 4 and provides the system operator and other asset owners with assurance that asset owners are co-operating to ensure protection is co-ordinated across the grid interface

4.1.3.4 Test outcomes

Testing of protection systems is required to confirm:

- protection is co-ordinated across the grid interface
- accuracy of primary circuit parameters and integrity of the tripping circuit components at the grid interface
- protection settings are properly identified, applied and checked to meet the outcomes set out in the 'Code'
- protection is coordinated with other asset owners at the grid interface
- protection remains coordinated, with other asset owners at the grid interface, after any modification and change at the grid interface

4.1.3.5 ACS Reference

The information is required in section 6.0 of the ACS

4.1.3.6 Tests that will achieve required outcome

Item	Description
Initial protection audit	Asset owners (either individually or collectively) who have not actively confirmed protection is co-ordinated should undertake an initial 'one-off' review of protection system co-ordination across the grid interface to ensure existing protection: ▪ is adequate ▪ meets the requirement for co-ordination at the grid interface. Such review should be carried out by an appropriately qualified independent expert.

Ongoing protection coordination	For asset owners to meet the AOPOs and technical codes in relation to protection each will need an effective management system to ensure the Test Outcomes set out above. . A means of ensuring the protection remains co-ordinated on an ongoing basis is for asset owners at the grid interface (individually or collectively) to engage an independent and suitably qualified person to audit the management system for protection of assets. Such audit should be conducted every 4-5 years and confirm there are effective systems in place to meet and maintain the EGR requirements for protection systems.
Relay tests	Protection systems depend: ▪ on the instrument transformers that give accurate measurements of the currents and voltages during faults on the primary circuit. ▪ on the trip circuits and circuit breakers into which they operate. Such components (the instrument transformers and trip circuits) may change without detection by the protection system Relay tests should be carried out to the individual asset owner's standard equipment test procedures.

4.2 Initial Tests Commissioning/Modification

4.2.1 Overview

4.2.1.1 Content

This part describes the Distributor tests used to provide sufficient information to verify the following:

- Load shedding profiles under the AUFLS scheme.
- Load characteristics.

Some of the tests detailed in this section duplicate those required for routine tests. (Section 4.1 Distributor Tests: Routine Testing) They are included here to make this a complete and stand alone section for commissioning and modification tests.

4.2.1.2 Structure

This part consists of the following sections:

4.2.2 Distributor AUFLS

4.2.2.1 Content

This section describes the test requirements for AUFLS equipment.

4.2.2.2 Application

This section applies to distributors who are required to provide AUFLS

4.2.2.3 Purpose of test

Testing is required following commissioning or modification of the AUFLS system.

4.2.2.4 Test outcomes

AUFLS is critical for assisting the system operator to manage and provide sufficient reserve to ensure security of the system

4.2.2.5 ACS Reference

To maintain security of the power system during under frequency events, by avoiding cascade failure, the system operator requires:

- profile data; and
- testing of the AUFLS relay functionality.

Distributors should discuss relay and load information with the grid owner where the grid owner has been involved in relay allocation.

4.2.2.6 Tests that will achieve required outcome

4.2.2.6.1 Automatic Under Frequency Load Shedding (AUFLS)

Item	Description
General	AUFLS tests are undertaken to confirm trip settings for AUFLS to operate. A series of tests are conducted on feeders using measured SCADA and metering data. This section details the requirements for all Distribution Asset Owners (DAOs) who are required to maintain an automatic under-frequency load shedding system. The percentage of total pre-event demand for two blocks of demand are required as per the Part 8, Schedule 8.3, Technical Code B, clause 7 subclause 6. The profile information required by the ACS takes into account the variability of the data according to time of day/season. Where Distributors are uncertain of the exact nature of the load, they should ensure that even accounting for uncertainty, enough load to meet the 'Code' requirements, can be shed.
Tests	Tests for frequency are based on the standard protection relay recommended tests. It should meet basic requirements as a minimum as follows: ▪ Meet the tolerances (frequency trip levels and time delays) set out in the 'Code', Part 8, Schedule 8.3, Technical Code B, clause 7, subclause 6. ▪ A frequency generator that is capable of ramping down from just above set frequency to just below set frequency should be used. ▪ Frequency measurement having an accuracy of ± 0.01 Hz over the frequency range of 40 to 60 Hz. ▪ Time resolution of ±10 msec. ▪ Under-frequency relay time delay should be included in total operation time from when the frequency drops below the specified threshold until the load shedding contacts are energised.

4.2.3 Distributor Load Characteristics

4.2.3.1 Content

This section describes the tests required to determine Distributor load characteristics.

4.2.3.2 Application

Load characteristic information is required to provide an accurate representation of the load and its response to fluctuations in voltage.

Specifically, the proportions of constant power, constant current, and constant impedance loads, which become important where voltage collapse risks arise due to high power transfers and/or contingencies in the grid. Currently, the constant impedance load is the only required data in the distributor ACS while constant power and constant current loads are to be stated, if known.

4.2.3.3 Purpose of test

Constant impedance load data required in the ACS. It needs to be updated whenever significant changes occur due to commissioning or modification to the load. Likewise, for constant power or constant current loads if they are known.

4.2.3.4 Test outcomes

Detailed knowledge of loads improves modelling and makes use of actual system capability rather than relying on conservative estimates.

As voltage changes, the three types of load of interest are:

- Constant power loads - MVA loads that do not change with voltage changes,
- Constant current loads - MVA loads that change linearly with voltage changes, and

Constant impedance loads - MVA loads that change non-linearly to voltage changes

4.2.3.5 ACS Reference

The tests are required to provide the constant impedance load data required in the ACS

4.2.3.6 Tests that will achieve required outcome

4.2.3.6.1 Load Characteristics for Modelling

Item	Description
Tests/Information	As per the Distributor ACS, only data for induction or synchronous motors above 5 MW is required. If manufacturer's information is not available, motor characteristics can be obtained by tests.
Relevant Standards	**IEC 60034-4: 1985,** Rotating Electrical Machines – Part 4: Methods For Determining Synchronous Machine Quantities From Tests. **IEEE Std 115-1995**, IEEE Guide: Test Procedures for Synchronous Machines: Part II – Test Procedures and Parameter Determination for Dynamic analysis. **IEEE Std 112-1996**, IEEE Standard Test Procedure for Polyphase Induction Motors and Generators.

4.2.4 Distributor Protection

4.2.4.1 Content

This section describes the minimum recommended routine testing for distributor protection assets.

Note that the System Operator does not require Asset Owners to submit protection test data. Instead, the purpose of this section is to recommend a minimum routine testing regime to ensure that the ACS assurances with regard to the compliance of protection systems with the ‘Code’ can be reasonably given by the Asset Owner.

4.2.4.2 Application

This section applies to distributor protection systems

4.2.4.3 Purpose of test

Co-ordination across the grid interface must be checked and confirmed for new or modified assets.

4.2.4.4 Test outcomes

Verification of the assurance given in the Asset Owner ACS with regard to protection assets being compliant with the ‘Code’.

4.2.4.5 ACS Reference

Nil

4.2.4.6 Tests that will achieve required outcome

Asset owners must confirm protection is co-ordinated across the grid interface for new or modified assets. One way of testing protection co-ordination has been achieved is for asset owners (either individually or collectively) to perform an initial review of protection system co-ordination across the grid interface to ensure existing protection:

- is adequate
- meets the requirement for co-ordination at the grid interface.

4.3 Tests for Equipment Covered by Ancillary Contracts

4.3.1 Overview

4.3.1.1 Content

This part describes the Distributor tests used to provide sufficient information to verify the following:

- FIR/SIR capability
- IL functionality

4.3.1.2 Structure

This part consists of the following sections:

Section	Title	Page
4.3.2	Instantaneous Reserve	78

4.3.2 Instantaneous Reserve

4.3.2.1 Definition

The provision of interruptible load, partially loaded spinning reserve and/or tailwater depressed reserve (in each case as either fast instantaneous reserve or sustained instantaneous reserve) available to counter an under frequency excursion arising from an event. The total response expected will be fast enough and in a quantity sufficient to arrest the fall in frequency (fast instantaneous reserve), and assist in the recovery of frequency (sustained instantaneous reserve)

4.3.2.2 Application

Instantaneous reserve can be provided by both generator and distributors.

4.3.2.3 Purpose of test

The System Operator needs to ensure the integrity of the Instantaneous Reserve Ancillary Service provision by issuing requirements to service providers for assessing the Reserve Capability of their assets. This is a proactive measure to provide the System Operator with confidence that adequate reserve will be available in case of an under-frequency event.

The reason for testing reserve capability is to allow the System Operator to model and manage the total system reserve in the market. Testing provides the System Operator with verification of the FIR/SIR capability of the Generator & Distributor, in response to a standard under-frequency curve used as a proxy for under-frequency events.

4.3.2.4 Test/ Information Requirement

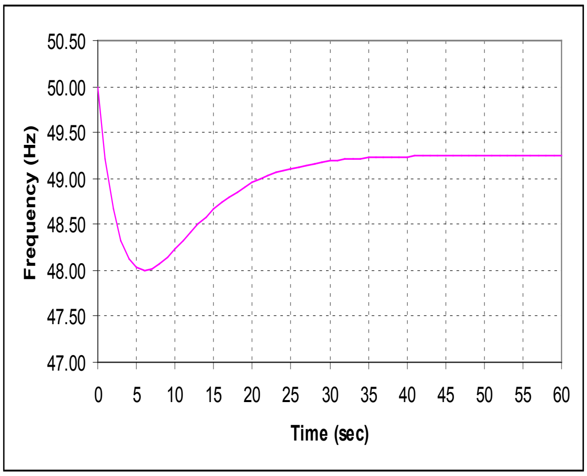
The response should also be provided electronically in tabular form with each measured channel in either comma or tab delimited text format. Note that Reserve Capability Testing is separate to other industry requirements of ongoing monitoring to record pre/post- event data.

4.3.2.5 Testing/ Information Frequency

Testing requirements are defined in Procurement Plan.

4.3.2.6 Tests that will achieve required outcome

4.3.2.6.1 Distributor Reserve Capability

Item	Description
General	This section details the basic technical requirements for all Distribution Asset Owners offering Fast Instantaneous Reserve (FIR) and/or Sustained Instantaneous Reserve (SIR) in the form of interruptible load. For the purpose of calculating reserve from test results in this case, the following definitions apply: ▪ FIR is the drop in load that occurs within 1 second of the grid frequency falling to or below 49.2 Hz and sustained for a period of at least 60 seconds. ▪ SIR is the average drop in load (MW) that occurs within 60 seconds of the frequency falling to or below 49.2 Hz, and which is sustained until advised by the System Operator.
Basic Test Requirements	**Drop Load Test** All tests need to be done by injecting a decaying frequency signal below 49.2 Hz at a rate of 0.5 Hz/sec into the under-frequency relay circuit to be able to time the chain of events after the under-frequency relay trips. An example of a frequency signal of standard under-frequency curve used to simulate a typical under-frequency event can be seen below in Figure 8.  *Figure 8: Standard Under-Frequency Curve* Accuracy of the measured load should be no less than 1% of the rated MW or 0.1 MW, whichever is larger. A rounding to the nearest 0.1 MW on the interruptible load offered per GXP will be used for calculating the maximum amount of reserve offered for each particular test. If only SIR is offered, a plot should be provided and a result table of load and frequency versus time at or less than six-second intervals for at least 60 seconds. This ensures sufficient data to determine the average load shed within the time limits for SIR calculations. The initial load is calculated as the average load over 60 seconds; for example at a scanning rate of 6 seconds, the initial load value is taken as the average of the last

10 (60/6) snapshots immediately prior to the frequency drop. The SIR capability is equal to the mean of the difference between the initial load and each of the next 10 (60/6) load snapshots until the end of 60 seconds from when the frequency dropped to 49.2 Hz. See Table 1and Figure 9: Example of SIR Test Result Output Graph for an example, based on a scanning rate of 5 seconds of what is required.

Frequency signal sent: 10:01:36

Result table:

Time	t (sec)	Frequency (Hz)	Load (MW)	1 minute Average Load (MW)	Difference (MW)
10:00:37	-55	50.08	25.3		
10:00:42	-50	50.01	25.2		
10:00:47	-45	49.91	25.1		
10:00:52	-40	50.00	25		
10:00:57	-35	50.00	25.4		
10:01:07	-30	49.90	25.6		
10:01:12	-25	49.80	25		
10:01:17	-20	49.85	24.8		
10:01:22	-15	49.96	24.6		
10:01:27	-10	50.00	24.7		
10:01:32	-5	50.00	25		
10:01:37	0	49.20	24.8	25.0	
10:01:42	5	48.00	22.2		2.8
10:01:47	10	48.32	18.1		6.9
10:01:52	15	48.73	12.5		12.5
10:01:57	20	48.99	5.8		19.2
10:02:02	25	49.13	2.1		22.9
10:02:07	30	49.20	0.2		24.8
10:02:12	35	49.23	0		25.0
10:02:17	40	49.24	0		25.0
10:02:22	45	49.25	0		25.0
10:02:27	50	49.25	0		25.0
10:02:32	55	49.25	0		25.0
10:02:37	60	49.25	0		25.0
Mean					**20.0**

Max. SIR provided: 20 MW or 80% of output.

Table 1: Example of SIR Test Result Calculations

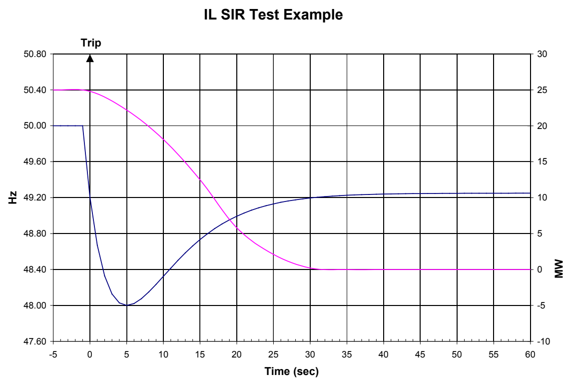


Figure 9: Example of SIR Test Result Output Graph

If FIR is also offered, you should provide a plot and a result table. This should plot load, frequency, and circuit breaker status or trigger signal (if applicable) versus time at less than or equal to 250 millisecond intervals for 1 second or as long as it takes for the load to complete its drop. This ensures sufficient data to determine the proportion of load shed within the time limits for FIR calculations. The initial load is calculated as the average load over 1 second; for example at a scanning rate of 100 milliseconds, the initial load value is taken as the average of the last 10 (1/0.1) snapshots immediately prior to the frequency drop. The FIR capability is equal to the difference between the initial load and the load snapshot one second from when the frequency dropped to 49.2 Hz. See the Figure 10 and Table 2 for an example of what is required, based on a scanning rate of 100 msec for two load profiles.

Frequency signal sent: 10:01:36

Result table:

Time	t (secs)	Frequency (Hz)	Load Line 1 (MW)	1 sec Average for Load 1 (MW)	Load Line 2 (MW)	1 sec Average for Load 2 (MW)
10:00:35.5	-1.5	50.00	5.1		5.5	
10:00:35.6	-1.4	49.99	5.0		5.4	
10:00:35.7	-1.3	50.00	5.0		5.4	
10:00:35.8	-1.2	50.00	4.9		5.5	
10:00:35.9	-1.1	50.01	4.9		5.6	
10:00:36.0	-1.0	50.00	5.0		5.6	
10:00:36.1	-0.9	49.91	5.1		5.5	
10:00:36.2	-0.8	49.82	5.0		5.4	
10:00:36.3	-0.7	49.73	5.0		5.4	
10:00:36.4	-0.6	49.65	4.9		5.5	
10:00:36.5	-0.5	49.56	4.9		5.6	
10:00:36.6	-0.4	49.49	5.0		5.5	
10:00:36.7	-0.3	49.41	5.1		5.5	
10:00:36.8	-0.2	49.34	5.0		5.5	
10:00:36.9	-0.1	49.27	5.0		5.5	
10:00:37.0	0.0	49.20	4.9	5.0	5.6	5.5
10:00:37.1	0.1	49.14	5.1		5.5	
10:00:37.2	0.2	49.08	5.0		5.5	
10:00:37.3	0.3	49.02	4.3		5.5	
10:00:37.4	0.4	48.96	3.4		4.9	
10:00:37.5	0.5	48.91	2.7		4.6	
10:00:37.6	0.6	48.86	2.3		4.3	
10:00:37.7	0.7	48.81	1.6		4.2	
10:00:37.8	0.8	48.76	0.7		3.9	
10:00:37.9	0.9	48.71	0.0		3.6	
10:00:38.0	1.0	48.67	0.0		3.3	
10:00:38.1	1.1	48.63	0.0		3.3	
10:00:38.2	1.2	48.59	0.0		3.0	
10:00:38.3	1.3	48.55	0.0		2.8	
10:00:38.4	1.4	48.51	0.0		2.5	
10:00:38.5	1.5	48.48	0.0		2.3	

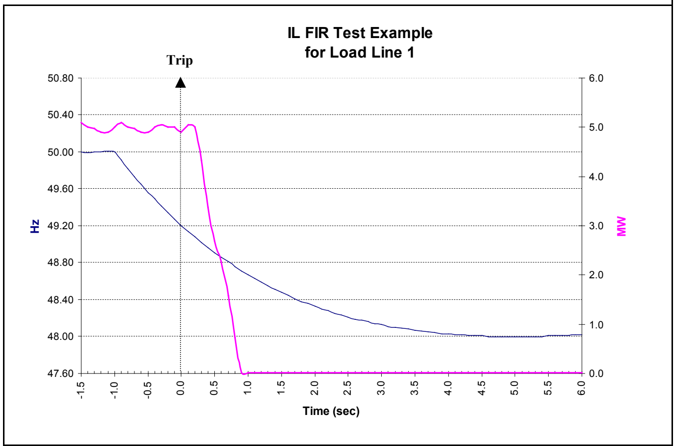
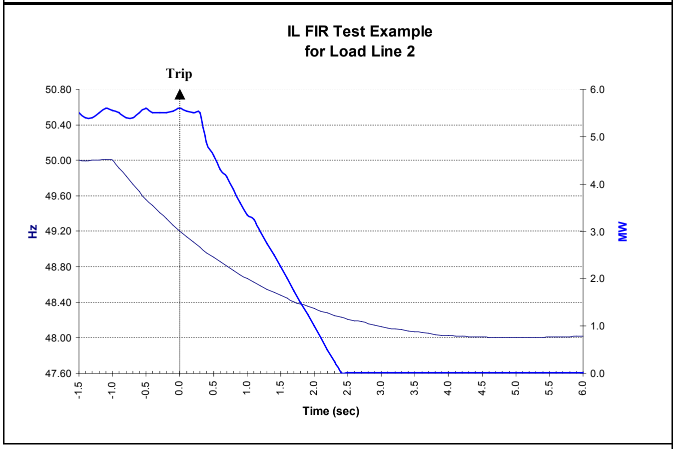
Summary of results:

	Line 1	%output	Line 2	%output
Max. FIR provided:	5.0	100	2.2	39

Table 2: Example of FIR Test Result Calculations

Independent load line tests

A separate test should be conducted for every non-identical load line (or lines) that can be separately armed, whether triggered by the same or a different under-frequency relay so that each complete chain of every interruptible load process is proven to work as expected when an under-frequency event occurs.

	  *Figure 10: Example of FIR Test Result Output Graph*
Constant Load test Requirements	Reserve provider plants, typically industrial sites, are assumed to operate on a constant rated load shown at the day of the test. If plant is not at full load for any trading period, reserve offered should be adjusted down in proportion to full load. Plants which cannot accurately predict interruptible load for every trading period during a full day will be treated as variable load (described below). A confirmation that if loads are tested separately, there is no aggregate effect or limitation on the overall plant, which could prevent the ability of total load tripping. A simulation of different combinations of loads simultaneously tripping after an event is a good example of confirming the plant control system logic for load interdependence. In order to change FIR/SIR offered maximums (possibly due to plant expansion), new tests should be conducted to quantify the new reserve capability.
Variable Load Test Requirements	Reserve providers, typically distributors offering domestic water heating for reserve, should account for the nature of variable load following a changing load profile over a weekday, a weekend/public holiday or a season. They are required to provide enough data to ensure that the system reserve capability is modelled according to real response.

	If the interruptible load is monitored, the load profile for the whole day (24 hours at least every half an hour) for every day of the week should be provided to the System Operator. Otherwise, enough tests should be conducted to draw a profile for the interruptible load, each test being long enough to capture the full load drop. It is anticipated that for each unique profile the test may have to be done over several days. Assuming that the load profile is divided into time blocks of constant interruptible load, FIR or SIR tests are to be conducted per block at equal intervals of the day, at least 12 tests or one test every 2 hours. Smaller time blocks (possibly for every trading period) may be required if load varies significantly within the proposed time block. The results of all the tests will determine if the amount of offered interruptible load is constant (limited by a ramp rate in the process) or varies in proportion to the total load. A daily interruptible load offer profile should be supplied based on the results of the drop load tests. If interruptible load patterns - between different days of the week (including weekends) or between seasons - exist, several daily interruptible load offer profiles should be supplied accounting for the patterns (based on further tests conducted at the relevant days or adjustment factors from historical data). Normal operating conditions should be reflected in the tests. Interruptible load offer profiles should account for any type of load control mechanisms operating within the plant; i.e. other load control schemes (for example to avoid peak loads) should not impinge on the total interruptible load offered. In order to change FIR/SIR offered maximums (possibly due to natural yearly load growth), new tests should be conducted to quantify the new reserve capability. Conversely, tests should be conducted in some areas for load decay and the daily interruptible load offer profile reduced accordingly.
Important Note	Test data is only indicative and reserve offers should always be conservative enough to ensure they can be met should they be dispatched and called upon. Actual under frequency events provide another source of data with which to adjust current offer profiles with actual data.