NS178

Secondary System Requirements for Major Substations

APRIL 2008

Amendments included from NSAs 1473 May 2008, 1480 Aug 2008, 1498 Nov 2008, 1515 Feb 2009, 1555 Jan 2010, 1602 Feb 2011 & 1667 Sep 2012

SUMMARY

Network Standard NS178 covers the planning and design requirements for secondary systems for subtransmission feeders, subtransmission substations and zone substations.

ISSUE

For issue to all Ausgrid and Accredited Service Providers' staff involved with the design of Ausgrid's major substations.

Ausgrid maintains a copy of this and other Network Standards together with updates and amendments on www.ausgrid.com.au.

Where this standard is issued as a controlled document replacing an earlier edition, remove and destroy the superseded document.

DISCLAIMER

As Ausgrid's standards are subject to ongoing review, the information contained in this document may be amended by Ausgrid at any time.

It is possible that conflict may exist between standard documents. In this event, the most recent standard shall prevail.

This document has been developed using information available from field and other sources and is suitable for most situations encountered in Ausgrid. Particular conditions, projects or localities may require special or different practices. It is the responsibility of the local manager, supervisor, assured quality contractor and the individuals involved to ensure that a safe system of work is employed and that statutory requirements are met.

Ausgrid disclaims any and all liability to any person or persons for any procedure, process or any other thing done or not done, as a result of this Standard.

Note that compliance with this Network Standard does not automatically satisfy the requirements of a Designer Safety Report. The designer must comply with the provisions of the WHS Regulation 2011 (NSW - Part 6.2 Duties of designer of structure and person who commissions construction work) which requires the designer to provide a written safety report to the person who commissioned the design. This report must be provided to Ausgrid in all instances, including where the design was commissioned by or on behalf of a person who proposes to connect premises to Ausgrid's network, and will form part of the Designer Safety Report which must also be presented to Ausgrid. Further information is provided in Network Standard (NS) 212 *Integrated Support Requirements for Ausgrid Network Assets*.

INTERPRETATION

In the event that any user of this Standard considers that any of its provisions is uncertain, ambiguous or otherwise in need of interpretation, the user should request Ausgrid to clarify the provision. Ausgrid's interpretation shall then apply as though it was included in the Standard, and is final and binding. No correspondence will be entered into with any person disputing the meaning of the provision published in the Standard or the accuracy of Ausgrid's interpretation.

Network Standard
NS178
Secondary System Requirements for Major Substations
April 2008

CONTENTS

1 Scope

This Network Standard:

- applies to all situations requiring planning or design of new (i.e. "greenfield") substation secondary systems for sub-transmission feeders, sub-transmission substations and zone substations, which will become part of Ausgrid's network
- applies, wherever practicable, to all situations requiring planning or redesign of existing (i.e. "brownfield") substation secondary systems for sub-transmission feeders, sub-transmission substations and zone substations, which are or will become part of Ausgrid's network. In such "brownfield" situations where it is not practicable to strictly apply the requirements of this Standard, it shall still serve as a guide with due regard for the following factors which will always remain mandatory: safety, National Electricity Rules (NERs), reliability and good engineering practice.
- applies to all persons with responsibility for planning or designing of substation secondary systems for sub-transmission feeders, sub-transmission substations and zone substations**,** including Ausgrid Staff, Contractors, Alliance Partners and Accredited Service Providers
- provides details, in separate Chapters, for the following types of substation secondary systems:
  - Protection Systems
  - Control Systems, including SCADA requirements
  - Metering Systems, including Indication of Metered Quantities
  - DC Systems, including Batteries and Battery Chargers.
  - Control Panels, Cabling and Wiring
- includes details, for each type of secondary system, of the design philosophy, including:
  - Functionality
  - Wiring Standards
  - Panel Layouts
  - Equipment Locations
  - Communications Protocols
- provides some detail of the installation or connection arrangements for the equipment described. Additional details may be provided in drawings referred to in the individual project 'scope of works' documentation.
- Does not include details of the following substation systems, which are provided in indicated Network Standards:
  - Building and Switchyard Systems, including light and power, security and fire detection/protection systems. Refer NS185 Major Substations Building Design Standard and NS186 Major Substations Civil Design Standard.
  - Environmental Monitoring systems, including temperature, wind and rain monitoring. Refer NUS174 Environmental Procedures
  - Communications systems for communications external to the substation. Refer NRS 203 Planning and Design Standards for Electrical Network Communications Assets
  - Engineering LAN requirements for local and remote interrogation and evaluation of non-operational substation status information. Refer NS 213 Network Design IEC61850 Compliant Substation. (which is being prepared.)

2 Objectives

The primary objectives of this Network Standard are:

- to ensure that sub-transmission feeders, sub-transmission substations and zone substations are fitted with necessary secondary systems,
- to ensure that National Electricity Market code compliance is achieved, as required, for both Protection and Metering systems,
- to identify requirements for each of the following substation configurations:
  - 132kV/66kV/33kV
  - 132kV/66kV
  - 132kV/33kV
  - 132kV/11kV
  - 66kV/11kV
  - 33kV/11kV

3 Protection Systems

3.1 Subtransmission Substations

Protection system requirements for Subtransmission substations are the same for 132kV/66kV/33kV, 132kV/66kV and 132kV/33kV substations.

3.2 132kV Feeders

The 132kV protection shall be designed to meet the reliability requirements and clearance time requirements of the National Electricity Rules (NER), Schedule 5.1.9. Stability studies may be used to identify feeders where compliance with the NER is not mandatory.

The preferred protection on each feeder is duplicate line differential with inter-trips. Distance or overcurrent (as appropriate and if approved) back-up built in to the line differential relays is required. Compliance with the NER is required, including intertrip requirements.

Diverse communication paths are to be provided within substations. Ausgrid will provide the necessary diversity external to substations.

3.2.1 66kV Feeders

Each 66kV feeder protection shall utilise standard designs for overhead or underground feeders. Each 66kV feeder shall be provided with two independent protection schemes. These schemes will be a combination of Line Current Differential, Distance or OCEF protection depending on the arrangement of the 66kV network.

For certain 66kV feeders compliance with the NER may be required, in which case the provisions for 132kV line protection are to be applied.

For certain 66kV feeders, it may be necessary to implement SEF protection. Project specific SEF implementation for 66kV feeders will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.2.2 33kV Feeders

Each 33kV feeder protection shall utilise standard designs for overhead or underground feeders. Each 33kV feeder shall be provided with two independent protection schemes. These schemes will be a combination of Line Current Differential, Distance or OCEF protection depending on the arrangement of the 33kV network.

For certain 33kV feeders, it may be necessary to implement SEF protection. Project specific SEF implementation for 33kV feeders will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.2.3 132kV/66kV and 132/33kV Transformers

Each transformer protection shall include the following:

- Duplicate biased differential protection
- Duplicate 132 kV high impedance restricted earth fault protection
- Single 132kV transformer neutral earth fault protection
- Main tank Buchholz
- Tap changer oil surge
- Duplicate 66kV (or 33kV) restricted earth fault protection
- Single 66kV (or 33kV) transformer neutral earth fault protection

Where the auxiliary transformer is supplied from the delta winding of a YNyn or Yna transformer, the auxiliary transformer protection will depend upon and be appropriate for the type of auxiliary transformer provided. The auxiliary transformer protection will trip the main transformer.

Phase and magnitude correction for CT and power transformer ratio and connection is to be done internally to the differential relays wherever this is possible with the relays specified.

3.2.4 132kV Busbars

Duplicated high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar.

3.2.5 66kV Busbars

Duplicated high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar.

3.2.6 33kV Busbars

Duplicated high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar.

3.2.7 66kV and 33kV Capacitor Banks

A capacitor bank protection scheme should be provided for each capacitor bank, consisting of:

- duplicated Overcurrent and Earth Fault protection for each capacitor bank, and
- duplicated Neutral unbalance protection.

Circuit Breaker fail function of one or more of these relays should be utilised to provide CBF protection.

An ABB SPAJ 160 Capacitor Bank Protection relay (or similar approved relay) may be used to provide one of the neutral unbalance protections. The harmonic overload features of this relay should also be utilised to trip the capacitor bank if harmonics are excessive.

3.2.8 Circuit Breaker Failure Scheme

Each Transformer protection scheme, Feeder protection scheme and Busbar protection scheme shall have an associated breaker failure protection scheme. The breaker failure schemes will be duplicated and function in both directions across the circuit breaker using independent relay schemes.

3.2.9 Auto Reclose Schemes

Auto-reclosing schemes will be implemented on all fully overhead 132kV, 66kV and 33kV feeders. The feeder auto-reclosing will be single shot with reclaim time and initiated by either of the feeder protections. A stand alone auto-reclosing relay will be used.

The auto-reclosing may be made ‘auto’ or ‘non-auto’ both locally on the associated feeder protection panel and via SCADA.

There will be no auto-reclosing implemented on fully underground feeders or feeders with significant underground sections or tail-ended feeders.

Project specific auto reclose implementations will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.3 Zone Substations

3.3.1 132kV/11kV Substations

3.3.1.1 132kV Feeders

The 132kV protection shall be designed to meet the reliability requirements and clearance time requirements of the National Electricity Rules (NER), Schedule 5.1.9. Stability studies may be used to identify feeders where compliance with the NER is not mandatory.

The preferred protection on each feeder is duplicate line differential with inter-trips. Distance or overcurrent (as appropriate and if approved) back-up built in to the line differential relays is required.

Diverse communication paths are to be provided where compliance with the NER is required within substations. Ausgrid will provide the necessary diversity external to substations.

3.3.1.2 132kV/11kV Transformers

Each transformer protection shall include the following:

- Single transformer biased differential protection
- 132kV Instantaneous overcurrent and time delayed earth fault protection
- Main tank Buchholz
- Tap changer oil surge
- 11kV overcurrent on each transformer 11kV bushing
- Earthing transformer neutral earth fault connected to a CT on the neutral earthing transformer neutral leg
- Overcurrent on the HV side of the neutral earthing transformer using CTs on the earthing transformer 11kV cables
- Earthing transformer Buchholz protection.

3.3.1.3 132kV Busbars

Duplicated high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar.

3.3.1.4 11kV Feeders

Each distribution feeder protection shall utilise standard designs for the relevant feeder class (underground or overhead) as follows.

- One 3-phase over current and earth fault relay, with IDMT and instantaneous elements for the protection of each feeder circuit.
- Sensitive earth fault protection relay with definite time elements, on overhead feeder circuits only. The sensitive earth fault protection is to be arranged to be individually enabled or disabled locally and via SCADA.
- Back-up overcurrent and earth fault relay tripping into the associated 11kV busbar protection wherever the transformer LV side overcurrent protection pick-up is greater than 67% of the fault current level at the end of the feeder.
- Double Banked Auxiliary Transformer/Capacitor Feeders are not to be equipped with SEF protection or auto reclose.
- Any doubled banked 11kV feeders shall have separate OCEF relays and separate SEF relays for each leg.

3.3.1.5 11kV Busbars

For single busbar switchgear, a high impedance busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

For duplicate busbar switchgear, a frame leakage busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

3.3.1.6 11kV Capacitor Banks

A standard capacitor bank protection scheme should be provided, consisting of:

- Overcurrent and Earth Fault protection for each bank, and
- Neutral unbalance protection for each capacitor step. The neutral unbalance relays should trip the capacitor bank Circuit Breaker or RMCB, not the faulted capacitor's step contactor.

3.3.1.7 Circuit Breaker Failure Scheme

Each Transformer protection scheme, Feeder protection scheme (above 11kV) and Busbar protection scheme shall have an associated breaker failure protection scheme. The breaker failure schemes will be duplicated and function in both directions across the circuit breaker using independent relay schemes.

3.3.1.8 Auto Reclose Schemes

Auto-reclosing schemes will be implemented on all fully overhead 132kV and 11kV feeders. The feeder auto-reclosing will be single shot with reclaim time and initiated by either of the feeder protections. A stand alone auto-reclosing relay will be used.

The auto-reclosing may be individually made 'auto' or 'non-auto' both locally on the associated feeder protection panel and via SCADA.

There will be no auto-reclosing implemented on fully underground feeders or feeders with significant underground sections or tail-ended feeders.

Project specific auto reclose implementations will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.3.2 66kV/11kV Substations

3.3.2.1 66kV Feeders

Each 66kV feeder protection shall utilise standard designs for overhead or underground feeders. Each 66kV feeder shall be provided with two independent protection schemes. These schemes will be a combination of Line Current Differential, Distance or OCEF protection depending on the arrangement of the 66kV network. OCEF protection is not to be used for both primary and back-up protection.

For certain 66kV feeders compliance with the NER may be required, in which case the provisions for 132kV line protection are to be applied.

For certain 66kV feeders, it may be necessary to implement SEF protection. Project specific SEF implementation for 66kV feeders will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.3.2.2 66kV/11kV Transformers

Each transformer protection shall include the following:

- Differential
- Main tank Buchholz
- Tap changer oil surge

- Primary earth fault
- Primary instantaneous overcurrent
- Secondary overcurrent and earth fault
- Auto change-over, as required

3.3.2.3 66kV Busbars

Single high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar. Remote backup protection provides backup for the non-duplicated 66kV BBP

3.3.2.4 11kV Feeders

Each distribution feeder protection shall utilise standard designs for the relevant feeder class (underground or overhead) as follows:

- One 3-phase over current and earth fault relay, with IDMT and instantaneous elements for the protection of each feeder circuit.
- Sensitive earth fault protection relay with definite time elements, on overhead feeder circuits only. The sensitive earth fault protection is to be arranged to be individually enabled or disabled locally and via SCADA.
- Back-up overcurrent and earth fault relay tripping into the associated 11kV busbar protection wherever the transformer LV side overcurrent protection cannot “see” to the end of the feeder.
- Double Banked Auxiliary Transformer / Capacitor Feeders are not to be equipped with SEF protection or auto reclose.
- Any doubled banked 11kV feeders shall have separate OCEF relays and separate SEF relays for each leg.

3.3.2.5 11kV Busbars

For single busbar switchgear, a high impedance busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

For duplicate busbar switchgear, a frame leakage busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

3.3.2.6 66kV Capacitor Banks

A capacitor bank protection scheme should be provided for each capacitor bank, consisting of

- Duplicated Overcurrent and Earth Fault protection for each capacitor bank, and
- Duplicated Neutral unbalance protection.

Circuit Breaker fail function of one or more of these relays should be utilised to provide CBF protection.

An ABB SPAJ 160 Capacitor Bank Protection relay (or similar approved relay) may be used to provide one of the neutral unbalance protections. The harmonic overload features of this relay should also be utilised to trip the capacitor bank if harmonics are excessive.

3.3.2.7 11kV Capacitor Banks

A standard capacitor bank protection scheme should be provided, consisting of:

- Overcurrent and Earth Fault protection for each bank, and
- Neutral unbalance protection for each capacitor step. The neutral unbalance relays should trip the capacitor bank Circuit Breaker or RMCB, not the faulted capacitor's step contactor.

3.3.2.8 Circuit Breaker Failure Scheme

Each Transformer protection scheme, Feeder protection scheme (above 11kV) and Busbar protection scheme shall have an associated breaker failure protection scheme. The breaker failure schemes will be duplicated and function in both directions across the circuit breaker using independent relay schemes.

3.3.2.9 Auto Reclose Schemes

Auto-reclosing schemes will be implemented on all fully overhead 66kV and 11kV feeders. The feeder auto-reclosing will be single shot with reclaim time and initiated by either of the feeder protections. A stand alone auto-reclosing relay will be used.

The auto-reclosing may be individually made 'auto' or 'non-auto' both locally on the associated feeder protection panel and via SCADA.

There will be no auto-reclosing implemented on fully underground feeders or feeders with significant underground sections or tail-ended feeders.

Project specific auto reclose implementations will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.3.3 33kV/11kV Substations

3.3.3.1 33kV Feeders

Each 33kV feeder protection shall utilise standard designs for overhead or underground feeders. Each 33kV feeder shall be provided with two independent protection schemes. These schemes will be a combination of Line Current Differential, Distance or OCEF protection depending on the arrangement of the 33kV network. OCEF protection is not to be used for both primary and back-up protection.

For certain 33kV feeders, it may be necessary to implement SEF protection. Project specific SEF implementation for 33kV feeders will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.3.3.2 33kV/11kV Transformers

Each transformer protection shall include the following:

- Differential
- Main tank Buchholz
- Tap changer oil surge
- Primary earth fault
- Primary instantaneous overcurrent
- Secondary overcurrent and earth fault
- Auto change-over, as required.

3.3.3.3 33kV Busbars

Single high impedance busbar protection scheme (with supervision), with separate scheme covering each section of busbar. Remote backup protection provides backup for the non-duplicated 33kV BBP

3.3.3.4 11kV Feeders

Each distribution feeder protection shall utilise standard designs for the relevant feeder class (underground or overhead) as follows:

- One 3-phase over current and earth fault relay, with IDMT and instantaneous elements for the protection of each feeder circuit.
- Sensitive earth fault protection relay with definite time elements, on overhead feeder circuits only. The sensitive earth fault protection is to be arranged to be individually enabled or disabled locally and via SCADA.
- Back-up overcurrent and earth fault relay tripping into the associated 11kV busbar protection wherever the transformer LV side overcurrent protection cannot “see” to the end of the feeder.
- Double Banked Auxiliary Transformer/Capacitor Feeders are not to be equipped with SEF protection or auto reclose.
- Any doubled banked 11kV feeders shall have separate OCEF relays and separate SEF relays for each leg.

3.3.3.5 11kV Busbars

For single busbar switchgear, a high impedance busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

For duplicate busbar switchgear, a frame leakage busbar protection scheme shall be provided. Transformer 11kV overcurrent and neutral earth fault protection provides backup for the non-duplicated 11kV BBP.

3.3.3.6 33kV Capacitor Banks

A capacitor bank protection scheme should be provided for each capacitor bank, consisting of:

- Duplicated Overcurrent and Earth Fault protection for each capacitor bank, and
- Duplicated Neutral unbalance protection.

Circuit Breaker fail function of one or more of these relays should be utilised to provide CBF protection.

An ABB SPAJ 160 Capacitor Bank Protection relay (or similar approved relay) may be used to provide one of the neutral unbalance protections. The harmonic overload features of this relay should also be utilised to trip the capacitor bank if harmonics are excessive.

3.3.3.7 11kV Capacitor Banks

A standard capacitor bank protection scheme should be provided, consisting of:

- Overcurrent and Earth Fault protection for each bank, and
- Neutral unbalance protection for each capacitor step. The neutral unbalance relays should trip the capacitor bank Circuit Breaker or RMCB, not the faulted capacitor’s step contactor.

3.3.3.8 Circuit Breaker Failure Scheme

Each Transformer protection scheme, Feeder protection scheme (above 11kV) and Busbar protection scheme shall have an associated breaker failure protection scheme. The breaker failure schemes will be duplicated (one for each protection scheme) and function in both directions across the circuit breaker using independent relay schemes.

3.3.3.9 Auto Reclose Schemes

Auto-reclosing schemes will be implemented on all fully overhead 33kV and 11kV feeders. The feeder auto-reclosing will be single shot with reclaim time and initiated by either of the feeder protections. A stand alone auto-reclosing relay will be used.

The auto-reclosing may be made ‘auto’ or ‘non-auto’ both locally on the associated feeder protection panel and via SCADA.

There will be no auto-reclosing implemented on fully underground feeders or feeders with significant underground sections or tail-ended feeders.

Project specific auto reclose implementations will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.4 Instrument Transformers

Instrument transformers for all protection systems shall be specified as part of the primary switchgear specification and associated period contract or part of the period contract for outdoor instrument transformers.

Project specific instrument transformer requirements will be as indicated in the specific substation single line diagram and associated drawings and plant data sheets.

3.5 Protection Equipment Locations

All protection relays and associated protection equipment (apart from 11kV feeder protection equipment) shall be mounted on stand-alone protection panels located in the substation. Protection panels shall generally be grouped in primary voltage groupings and functions. Duplicate protection schemes (A and B Protection) shall be located on adjacent panels. Where batteries are duplicated, protection systems are to be spread across the batteries to maximise redundancy.

In the case of 11kV feeders, the protection relays and associated protection equipment shall be mounted on and in the instrument cabinet associated with the 11kV feeder panel.

Refer to Section 7.1 for further control panel details.

3.6 Protection Wiring

Refer to Sections 7.1 and 7.2 for details of protection wiring requirements.

Schematic diagrams for protection systems are dependent on the specific substation.

Project specific substation single line diagrams and associated drawings and plant data sheets will include a list of the relevant protection wiring diagrams for the most recent example of that particular type of substation.

3.7 Preferred Protection Relay Types

The preferred protection equipment is that available on the Ausgrid period contracts current at the time. Other relays that may not be available on contract to Ausgrid may be used provided they are acceptable and have been approved for use at the design proposal stage of the project.

4 Control Systems

4.1 Substation SCADA System

The substation Supervisory Control And Data Acquisition (SCADA) system shall include the following:

- Control and Dual Indication of all 132kV, 66kV, 33kV and 11kV circuit breakers;
- Control and Dual Indication of each CB Auto-reclose;
- Control and Dual Indication of each Bus Section Auto-closing Scheme;
- Control and Dual Indication of each 11kV SEF protection scheme;
- Monitoring of substation load, each transformer load and all high voltage feeder loads; (amperes and MVA at 132kV);
- Indication of Normal/Abnormal loading of Transformers which may be set from the local control panel or via SCADA.
- Monitoring of incoming feeder voltages and 11kV Bus Voltages;
- Indication of transformer thermal temperatures and temperature alarms;
- Control and Indication of transformer Tap Position and Voltage Regulation scheme;
- Group Earth Fault indication on each Transformer
- Monitoring of Substation AC and DC Systems;
- Control and Indication of Audio Frequency Load Control Equipment (AFLC);
- Monitoring of Substation Fire Protection Systems;
- Monitoring and control of capacitor installations;
- Operator Control Interface;
- Satellite (GPS) time synchronisation;
- Indications from any substation security system.
- Substation Protection Trip Indication, fleeting and latching indications with reset of the latching indication from the SCADA system
- The ability to reset all substation alarms on the substation HMI via a control from the SCADA system.

The use of dual indications (eg indications for both the open and close contacts) shall be provided for all switchgear and other monitored states where indicated.

The SCADA controls and indications shall be implemented by wiring the equipment status contacts from the switchgear and alarm contacts from the protection relays, along with analogue values from the transducers into Distributed Control Interface (DCI) units. The DCIs shall form part of a Semi-Distributed Control System (SDCS) in the substation building. The SDCS shall incorporate an Operator Control Interface, consisting of HMI and keyboard, as well as a remote terminal unit (RTU) or interface equipment to communicate with the Central Control Room via the SCADA master Station. All communications between DCIs, HMI and the RTU are to be via a dual redundant optical fibre line using multi-mode fibre.

The communications bearer to the Master Station will be determined by the available communications channels at the time (see section 4.2).

Other non-operational substation data and indications shall routed via the Engineering LAN rather than the SCADA system.

To permit local testing, facilities on the HMI shall be provided to provide an indication to the SCADA system for groups of signals which will cause the SCADA master station to not alarm changes of state of any signals in the group while the indication is active.

4.1.1 Summary of Indication and Alarms

Depending on the substation voltages, the primary control point(s) will have the following indications and alarms. For MVA, MW and MVAr indications the power flow convention is positive for power flows into a busbar or into the primary terminals of a transformer, and negative for power flows out of a busbar.

132kV Indications and Alarms:

- All Substation equipment status and alarms, including battery alarms, protection relays alarms, Voltage Regulation alarms and circuit breaker spring charge alarms.
- Status of all circuit breakers, disconnectors and earth switches.
- 132kV feeder three phase current and three phase voltage and MVA, MW and MVAr.
- 132kV bus-section single phase current.

66kV Indications and Alarms:

- All Substation equipment status and alarms, including battery alarms, protection relays alarms, Voltage Regulation alarms and circuit breaker spring charge alarms.
- Status of all circuit breakers, disconnectors and earth switches.
- 66kV feeder three phase current and three phase voltage and MW and MVAr.
- 66kV bus-section single phase current.

33kV Indications and Alarms:

- All Substation equipment status and alarms, including battery alarms, protection relays alarms, Voltage Regulation alarms and circuit breaker spring charge alarms.
- Status of all circuit breakers, disconnectors and earth switches.
- 33kV feeder three phase current and three phase voltage and MW and MVAr.
- 33kV bus-section single phase current.

11kV Indications and Alarms:

- All substation equipment status and alarms, including battery alarms, protection relays alarms, Voltage Regulation alarms and circuit breaker spring charge alarms.
- Status of all 11kV circuit breakers, disconnectors and earth switches.
- 11kV transformer three phase current, three phase voltage and power factor.
- 11kV feeder single phase current.
- For double banked feeders incorporating a capacitor bank and feeder connections, outgoing feeder current shall be monitored.

11kV Capacitor Indications and Alarms:

Alarms, indications and controls provided from the capacitor bank and the control and protection system should be connected to the SCADA system. Note that individual metering/SCADA indication for both the capacitor and the feeder are required.

The following indications, functions and alarms must be available via SCADA.

- Status of each capacitor bank circuit breaker and isolator and each capacitor step's contactor
- Ability to enable and disable automatic control of capacitor steps and to switch these steps manually
- Over temperature alarm

- Details of Neutral Unbalance and Overcurrent protection operation

33kV and 66kV Capacitor Indications and Alarms

An indication of the status of the capacitor bank circuit breaker, and indications and alarms from the protection relays, should displayed locally and remotely via SCADA.

Control should be provided to allow for remote switching of the capacitor bank.

4.1.2 132kV, 66kV and 33kV Equipment

Primary Control and Indications

The primary control point for operation of all circuit breakers will be from the screen based SCADA system, either remotely at the Central Control Room or locally at the Operator Control Interface HMI and keyboard.

The Operator Control Interface (HMI) at the substation shall be duplicated for all sub-transmission substations and for those 132/11kV substations where the requirements of the NER apply to the protection requirements for the 132kV feeders and for those 66/11kV substations where the requirements of the NER apply to the protection requirements for the 66kV feeders

All disconnectors shall be operated manually with remote status indication via SCADA.

The primary control point for the 132kV motorised earth switches shall be via a “wander lead” at the earth switches.

Back up Control and Indications

All SCADA controls will be backed up by a hard wired control to cater for the event of a simultaneous local and remote SCADA failure.

In the case of indoor switchgear, the individual bay local control panel may be used for back up operation

Back up operation of the feeder circuit breakers which are not supplied with local control facilities will be via illuminated push buttons located on the respective ‘B’ protection panel. A single phase current ammeter and circuit breaker status indication will be provided on the panel.

Back up operation of the Bus-section circuit breaker will be via illuminated push buttons on the Bus-section control panel. A single phase current ammeter and circuit breaker status indication will be provided on the panel.

Back up operation of the transformer primary circuit breakers will be via illuminated push buttons located on the transformer B protection panel. No ammeter will be provided on the panel as the transformer primary breaker is energising the transformers only, it does not switch onto load.

4.1.3 11kV Switchgear

Primary Control and Indications

The primary control point for operation of all 11kV equipment including the 11kV bus section/coupler auto-closing will be from the screen based SCADA system either remotely at the Central Control Room or locally at the Operator Control Interface HMI and keyboard.

Secondary Control and Indications

- All SCADA controls will be backed up by a hard wired control to cater for a simultaneous local and remote SCADA failure.
- Back-up operation of all 11kV internal arc classified circuit breakers will be via push buttons located on the 11kV switchgear front panels.
- Back-up control of 11kV feeder SEF and auto-reclose will be available locally on the respective 11kV switchgear front panels.
- Back-up controls and indications for the 11kV bus section auto-closing will be provided on the 11kV bus section auto-closing panel.
- Back-up indication of 11kV feeder current will be via the feeder main protection relay display.

4.1.4 Capacitor Bank Control

11kV Capacitor Banks

Switching of the capacitor banks and each individual step shall be automatically controlled to provide power factor correction. The control scheme shall provide automatic control:

- When the zone is operating normally
- With one transformer out of service

The power factor correction must be controlled automatically. A standard capacitor control scheme, using ABB REF relays programmed to the standard Ausgrid capacitor control standard, should be provided.

The REF relays should be interconnected to allow the capacitors to be controlled for the bus bar configuration that will result after failure of one transformer.

The control panel should include:

- a power factor meter (clearly labelled – “for indication only”);
- auto/manual switches to allow the automatic controller to be enabled or disabled;
- add capacitor and remove capacitor controls to allow for manual switching of capacitors;
- sufficient links to allow isolation of the system for calibration and testing.

33kV and 66kV Capacitor Banks

An automatic control scheme is not required. Provision should be made for the switching of both of the capacitor banks from the local control room and via SCADA.

Although detailed operating procedures should ensure that capacitors are not energised when they still have a residual charge, a simple 5 minute “lockout timer” should be installed to prevent closing of the circuit breaker, for 5 minutes after it has been opened either manually, or via the protection scheme.

4.1.5 Power Transformers

Transformer Indication and alarms:

- All transformer status alarms, including tapping switch positions
- Oil temperatures and associated alarms
- Cooling system status
- A manually set load status (Normal /Abnormal) which may be set/reset locally or via the SCADA system
- Voltage regulation system status

Voltage Regulation Control, Indication and Alarms:

The primary control point for operation of all voltage regulation and transformer control equipment will be from the screen based SCADA system (either remotely at the Central Control Room or locally at the Operator Control Interface HMI and keyboard).

All SCADA controls will be backed up by a hard-wired control to cater for the event of simultaneous local and remote SCADA failure. Back up operation of all voltage regulation and transformer control equipment will be via push buttons and control switches located on the voltage regulation panels. Facilities to disable SCADA control of the tap changer and Voltage Regulation equipment via a switch shall be provided for maintenance, this shall energise both the Dual indications (Auto and Manual) of the Voltage regulation status of the SCADA system.

4.1.6 Protection Trip Indication

Any switchgear operation as the result of a protection operation shall initiate two signals to the Control Centre SCADA system:

- A fleeting input for the duration of the protection operation
- A latched indication initiated by the protection operation

The latched input shall be reset by a control to the latch from the SCADA system.

4.2 Voltage Regulation

The main transformer tap changer control panels shall be located in the substation Control Room and shall use a standard VR scheme which consists of a VR relay, and an independent voltage monitor relay. If transformers in the substation operate in parallel, a parallel operating scheme will be required. The parallel operating scheme will be of a type approved by Network.

The auto/manual/local switch, manual tap raise/lower facility, tap position of the transformers, the high low voltage alarm and panel no voltage alarm shall be interfaced to the Semi-Distributed Control Interface units, allowing control and indication at the substation Operators Desk as well as at the Central Control Room. Other alarms generated by the parallel operation scheme should also be interfaced to the Semi-Distributed Control Interface units.

4.3 Audio Frequency Load Control

Audio Frequency Load Control (AFLC) equipment is installed at 132/11kV, 66/11kV and 33/11kV zone substations.

Static Frequency Units (SFU) supplying AFLC plants, each comprising a correctly rated coupling cell, shall be provided to facilitate load control at 1050Hz, 750 Hz or 500Hz, depending upon the control frequency used in the substation area.

The coupling cell is to be connected to an appropriate 11kV feeder CB at the 11kV switchboard.

The details and connection locations will be nominated by Subtransmission Planning and shown on the Project Specific substation single line diagram and associated drawings and plant data sheets.

The first preference for the location of the AFLC plants is in outdoor kiosks separate from the main switchroom buildings.

Where the AFLC plants are required to be located within the substation building, a single AFLC room only shall be provided. The AFLC room will be located such that an overpressure caused by an AFLC capacitor can rupture would not damage the main substation building. This may be best achieved by the AFLC room sharing only one or two common walls with the main building.

4.4 Substation Remote Terminal Unit

LogicaCMG supplies Remote Terminal Units (RTUs) under Ausgrid Purchasing Specification EA7747T/05. The LogicaCMG RTU and associated DCI Units will comprise the necessary number of LogicaCMG units.

Specific details of the SCADA protocols are not included in this document as the LogicaCMG equipment supports all of the necessary protocols

Communications between the substation and the Ausgrid Control Centre shall be achieved by either an external fibre optic cable, to be supplied and terminated by Ausgrid, or a radio link to be provided and installed by Ausgrid

Communications between the RTU and the fibre optic cable or radio system shall be via RS232 Interfaces.

5 Metering Systems

Refer to the interim document NS178 (Metering only) for the planning and design requirements for metering.

6 DC Systems

6.1 Batteries

One or two sets of batteries are required, depending on the substation type and voltage levels. Two batteries are required in substations with a highest voltage of 132kV. One battery is required in substations with a highest voltage of 66kV or 33kV, unless a requirement for two batteries is indicated in the Project Specific substation single line diagram and associated drawings and plant data sheets. The battery voltage shall be 110V dc.

Batteries will be of the valve regulated type, either NiCd or lead acid. The required duty cycle and parameters to determine the size and rating of the battery is outlined in NEG SM04.06 ‘Selection of Substation Batteries’.

In addition to the cumulative SCADA, control and protection loads, the battery must also allow for the load of the MPLS cabinets installed in the substation. These cabinets may contain an Alcatel 7250 or similar edge device, rated for 170W consumption, together with an Alcatel 7450 router or similar, rated at 380W consumption, plus any additional protection communications equipment such as mulitplexer.

There is no requirement for dedicated battery rooms as described in AS2676. Instead the batteries will be housed in the substation building in cabinets or otherwise as acceptable in terms of AS2676. The floor should be of strength suitable to cater for the mass of the battery.

6.2 Battery Chargers

A separate, suitably rated temperature compensated and matched battery charger shall be provided for each of the batteries. Battery Chargers and condition monitors shall be purchased to match the batteries.

A ‘Charger Fail’ alarm is to be connected to the SCADA system.

The battery charger, or dc distribution board, is to be fitted with “Low DC Volts”, “High DC Volts” and a “Battery Earth” alarm. Indication of these alarms is required locally on the battery charger (or dc distribution board) and remotely to the central control room via SCADA.

The “Low Volts” alarm should preferably be set at 92% of float voltage.

The “High Volts” alarm should preferably be set within the range of 110% to 120% of float voltage.

6.3 DC Distribution Boards

The DC distribution and extension boards shall be Ausgrid design type 12A for the ‘A’ DC supply and type 12B for the ‘B’ supply, in accordance with Drawing 191059_01.

Double insulated 0.6/1kV cabling enclosed in protective metal conduits shall be provided between the battery and the charger.

6.4 DC Wiring

General requirements for dc wiring are dependent on the specific substation.

Project specific substation single line diagrams and associated drawings and plant data sheets will include a list of the relevant dc wiring diagrams for the most recent example of that particular type of substation.

The dc system is unearthed and an earth detection relay is to be installed on each separate dc system within the substation

7 Control Panels, Cabling and Wiring within Substations

7.1 Control Panels

Control panels shall be generally designed so that the front of the panel is used for the flush mounting of relays, meters, switches etc and the rear of the panel is used to gain access, via a door, to the cabling, terminal blocks and wiring.

Tunnel board type control panels are not acceptable.

The control panels shall generally be 2000 mm high and either 600 mm or 750 mm wide depending on the quantity of equipment being installed.

Each individual functional section (eg, Transformer 1 and Transformer 2) shall be clearly segregated from any other section means of a 25 mm wide black line or a completely separate control panel.

Control panel layout, wiring and connections are dependent on the specific substation. Project specific substation single line diagrams and associated drawings and plant data sheets will include a list of the relevant protection wiring diagrams for the most recent example of that particular type of substation.

All control panels shall be finished in “Cloud Grey” Colour Number N22 to AS2700 on the exterior and white interior.

All control panels and panel equipment shall be labelled in accordance with NS158 – Labelling of Mains and Apparatus.

Control panel wiring shall comply with the requirements of AS/NZS 5000.1 Also refer to Ausgrid Drawing No. 114601

The test link type shall be moulded type, supplied and installed in accordance with Ausgrid drawing No. 38841

All protection relays are to have test links in the AC and DC circuits for testing contacts and isolating supplies.

The links are to be mounted so that if the sliding section is loosened, it will fall to the open position.

The links are to be mounted in horizontal rows at the locations specified below:

- Centre of the panel for full height panels
- Top of the panel for bottom half panels
- Bottom of the panel for top half panels

Links associated with “A” Protection and “B” Protection shall be segregated if mounted on the same panel and the following wiring conventions are to be adopted:

For CT and VT Circuits, connections closest to associated CT's or VT's to be wired to bottom of link and connections to relay to be wired to top of link.

For DC Circuits, connections to and from adjacent panel/s to be wired to bottom of link and connections to associated relay to be wired to the top of the link.

Connections between relays internal to the panel should be from the supply source to the top then from the bottom of the link to the destination equipment or neutral.

All connections between control panel wiring and control cables shall be via terminal blocks, mounted on vertical rails, inside each control panel.

Ausgrid's standard terminal block types shall be “Utilux” type H3820 (un-slotted link) and H3869 (slotted link). H3869 type terminal blocks shall be used wherever the terminal block will be required for isolation purposes. Details of the terminal blocks and mounting rails are shown on drawing No. 118547.

7.2 Control Cabling

Control wiring will consist of suitably protected multi-core control cables. Each multi-core cable will only service one item of equipment.

Where practicable all cables connected to one group of switchgear must be segregated in the switchrooms and en route to the control room from control cables connected to any other group of switchgear.

Each multi-core control cable shall be identified by a numbered label at each end and at convenient points along the route.

The following reference documents define control cable requirements:

- AS/NZS 5000.1- Electric cables – polymeric insulated for working voltages up to 0.6/1 kV
- AS/NZS 5000.3 - Electric cables – polymeric insulated multi-core control cables
- AS/NZS 3808 – Insulating and sheathing materials for electric cables
- Ausgrid Network Standard NS158 – Labelling of Mains and Apparatus
- Ausgrid Drawing No. A2 057591 19 – Zone Substations Multicore Cables
- Ausgrid Drawing No. 49806 11 – Zone Substations Standard Combined Cable Trench and Drain Details
- Ausgrid Drawing No. 118547 1 – Substation DIN Rail Mounted Terminals “Utilux” Type H3820 and H3869 General Arrangement and Stock Code No.

Low voltage control cables for Protection, Autoclosing and AC/DC Supplies shall comply with the requirements of AS/NZS 5000.3 – Electric cables – polymeric insulated for working voltages up to 450/750V.

Low voltage control cables for solenoid and motor 110V dc supplies shall comply with the requirements of AS/NZS 5000.1 – Electric cables – polymeric insulated for working voltages up to 0.6/1.0kV.

Low voltage control cables for Control, Indication, Measurement, Signals and Autoclosing Auxiliary Circuits shall comply with the requirements of AS/NZS 5000.3 – Electric cables – polymeric insulated for working voltages up to 450/750V.

Low voltage Screened Twisted Pair (STP) Instrumentation Cables for Supervisory Measurement Circuits shall comply with the requirements of AS/NZS 5000.3 – Electric cables – polymeric insulated for working voltages up to 450/750V.

Underground and external, Unscreened Twisted Pair (UTP) Telephone Cables for Tap Position Indication, Signal, Supervisory and DATT Circuits shall be jelly filled and shall comply with the requirements of Austel Standard 008.

7.3 Installation and Jointing of Control Cables

Under no circumstances will jointing or splicing of control cables be allowed. Control cables should be continuous from source to destination; however where continuous cables are not practicable connection shall be achieved via terminal blocks in a marshalling cubicle.

Where control cables are gathered and laid in trenches or conduits, the trench or conduit shall be large enough to ensure that they are never more than half full of cables.

Protection cables relating to A and B protection shall be run via separate routes.

Where practicable all control cables connected to one group of switchgear must be segregated in the switchrooms and en route to the control room from control cables connected to any other group of switchgear.

Each multi-core control cable shall be identified by a numbered label at each end and at convenient points along the route.

All control wiring shall be numbered and coloured in accordance with Ausgrid's current standard as shown on Drawings No. 057591 and 114601.

To reduce the effect of transients and interference, all installations are to have AC, DC and SCADA wiring run in separate cables.

Cables fitted with an overall screen, are to be earthed at one end only (preferably the source ends). Earthing conductors shall be stranded copper of minimum cross sectional area of 2.5 square millimetres with the standard green-yellow coloured insulation.

All SCADA cabling shall be run in screened multi-core twisted pair cable.

Pulsed output signals shall not be run in the same screened cable as digital input or analogue input signals.

It is permissible to run digital input signals in the same cable as analogue input signals PROVIDED that the cores carrying the different signals are not in the same twisted pair.

Each end of a core shall be provided with core identification ferrules. The ferrules shall be Telemecanique (Type 200 AI-MB01) or similar as approved by Ausgrid. Ferrule colours shall be white background with black lettering.

Wire codes are to be as per Appendix D of AS 2067.

No pressure or tension shall be exerted on the termination. The weight of the multicore cable shall be taken by cable glands, cable clamps or cable ties.

All equipment terminals shall be of the screwed type. Quick connector spade type terminations shall not be used.

All UTP telephone cables shall be terminated on Krone LSA Plus termination blocks.

Compression type solderless lugs shall be used at the terminations of all stranded wires. The lugs shall be manufactured from high conductivity seamless copper tube stock and the correct size of lug and compression tool should be used to suit the wire. The shank of the lug shall be protected by insulating tubing to prevent direct or accidental contact with adjacent terminations. A Utilux type H2037 terminal lug or an approved equivalent is required

7.4 Cable Ladders

The design, manufacture and installation of cable ladder shall comply with the requirements of NEMA VE 1-1984

Cable ladder shall have a load capacity equivalent to NEMA Class 16B. The maximum safe load shall be 245 kg/m at 3.0-m support spacing with a factor of safety of 1.5.

Cable ladder shall be fabricated from steel with horizontal rungs at 300-mm spacing welded to vertical side rails. Slots shall be provided in the horizontal rungs for cable fastening. The design of the side rail profile shall minimise the possibility of collecting spillage material and liquids within spaces in the side rail, particularly where cable ladder is installed on edge. All cable ladder and fittings shall be hot dip galvanised after fabrication. Aluminium cable ladder can be used as an alternative -it also can be utilised for basement earthing conductor provided it has sufficient short time rated earth fault-current carrying capacity.

All cable ladders shall have a spare capacity of at least 25 per cent of ladder width after all cables are installed.

The route shall be designed to be clear of pipes and valves and shall not obstruct access to plant and equipment. The cable ladder shall be designed for straight lines parallel to walls and floors. Where cable ladders are installed one above the other the minimum spacing between each level of ladder shall be 300 mm. Cables shall be arranged with power cables positioned above control and instrumentation cables.

Where cable ladders are installed in plant rooms or across walkways the minimum clear height from floor or ground level to underside of ladder shall be 2.1 m.

Factory fabricated bends, risers, tees and crosses shall be used for all connections and changes of direction. All fittings shall maintain the specified minimum bending radius for the largest cable to be installed on the ladder run.

Support brackets shall be installed at the required spacing to suit the load capacity of the cable ladder and to limit mid span deflection to a maximum of 20 mm with all cables installed. Support brackets shall be provided at all connections or changes of direction in accordance with the recommendations of NEMA VE 1. Support brackets shall be fabricated from Unistrut channel and accessories. Cable ladder shall be firmly attached to each support bracket using hold-down clamps designed for the purpose. Wherever possible brackets shall be installed to support the cable ladder from one side only, so as to leave the other side open for easier installation of cable, unless centre support brackets are utilised

In areas exposed to direct sunlight or where cables would be vulnerable to damage from falling objects or build-up of spillage material, continuous galvanised steel cable ladder covers shall be fitted. Covers shall be peaked to give rigidity and shall allow air circulation to avoid additional de-rating of the cables. Covers shall be securely attached to the cable ladder with clamps or hook bolts of an approved design and which allow easy removal and replacement.

All cable ladder runs shall be electrically continuous and securely bonded to the main earthing system with minimum 70 mm^2 insulated cable.

7.5 Control Cable Trenches, Conduits and Pits

Control and Protection cables within an outdoor switchyard area shall generally be installed in cable trenches with removable covers or in conduits between pre-cast cable pits. Requirements for Trenches, Conduits and pits are fully specified in NS186 Major Substations Civil Design Standard. Cable trenches shall be in accordance with Ausgrid Drawing No. 49806 11 – Zone Substations Standard Combined Cable Trench and Drain details.

7.6 Fibre Optic Control Wiring

The requirements for fibre optic cabling within substations, including cable types, cable routing and cable terminations are identified in NRS 203, Planning and Design Standards for Communication Assets used with Protection Systems, NRS 208 Design and Installation of Ausgrid Communication Cabinets and NS 213 Network Design IEC61850 Compliant Substation, which is under development.

8 Communications Protocols

8.1 Present Practice

Ausgrid has implemented a number of different protocols for SCADA systems within substations. The present practice is to use DNP3. In some instances DNP3 is also used as a communications protocol for integrated protection systems.

8.2 IEC 61850 Implementation

It is intended that Ausgrid implement a process to define substations and substation equipment in accordance with IEC 61850. One aspect of IEC 61850 is the protocol which devices use for communications within the substation. It is intended and anticipated that the IEC 61850 communications protocol will be implemented in two stages as follows:

8.2.1 Stage 1: Specify 61850 as the standard protocol for all substation communications

(a) Adopt the 61850 standard for all device communication within the substation, by undertaking the following practices:

- amend current standards to adopt the 61850 protocol; and
- develop and publish a specific 61850 specification to be used for all new substation and retrofit substation equipment.

(b) Review and progressively replace existing substation equipment contracts to include 61850 as standard in all new substation Intelligent Electronic Devices (IEDs).

(c) Undertake a SCADA RTU replacement program to install the 61850 distributed architecture when identified work is undertaken at major substations and incorporate this architecture into the monolithic RTU replacement program.

(d) Develop both an IT and telecommunications architecture and test plan that looks at a future best practices environment to ensure the highest level of security is maintained whilst facilitating a wide range of applications to utilize the available data.

(e) Provide centrally managed Communications Network Operations Centre (NOC) processes for managing communications switches within the substation and configured to allow both SCADA and Engineering LAN networks to operate separately within the substation. Refer NS 213 Network Design IEC61850 Compliant Substation, which is under development.

8.2.2 Stage 2: Integrated Protection and Control using 61850

(a) Undertake appropriate testing of integrated control and protection functions through the validation of a test plan within an Ausgrid laboratory environment.

(b) Progressively adopt 61850 functionality within substations.

(c) Develop an integrated control and protection standard design that is implemented on all new substation proposals.

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