Substation automation systems

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Automation Design Instruction

ADI 0012    SUBSTATION AUTOMATION SYSTEMS

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1.0 PURPOSE

To set out in detail the requirements for substation automation systems (SAS) in Endeavour Energy’s transmission substations, switching stations and zone substations.

The operational need for substation automation systems includes the control and monitoring of substation primary plant and the real-time reporting of power flows in the electrical network. Substation automation and SCADA systems are core tools for system operations, network planning and the evolving distribution network.

2.0 SCOPE

This document covers substation automation systems for the purpose of performing manual and automated monitoring and control of plant and equipment within new or refurbished transmission substations, switching stations, and zone substations operated by Endeavour Energy.

This document includes;

- System requirements.
- Component requirements.
- Automation functions.
- Primary plant supervisory and control requirements.
- Management of legacy equipment.

The relevant information from the Australian and International standards have been summarised in this document. In the event of inconsistencies and/or conflicts between the requirements outlined within this document and the Australian and/or International standards the requirements within this document shall take precedence.

3.0 REFERENCES

**Internal**
- Company Policy 9.1.10 – Network Electrical Safety
- Company Policy 9.2.5 – Network Asset Design
- Company Policy 9.7.1 – Network Asset Construction
- Company Policy 9.9.1 – Network Asset Maintenance
- Company Procedure GAM 0001 – Network Standards Framework: Preparation And Amendment Of Network Standards
- Company Procedure GAM 0089 – Authorisation governance and management
- Network Management Plan December 2013 Review
- Electrical Safety Rules
- Substation Design Instruction SDI 505 – Minimum design and construction requirements for transmission and zone substations and switching stations
- Substation Design Instruction SDI 526 – Control cabling, panels and terminations
- Automation Design Instruction ADI 0006 – Communications in Substation

**External**
- *Work Health and Safety Act 2011*
- *Work Health and Safety Regulation 2011*
- ENA Guideline for the preparation of documentation for connection of Embedded Generation within Distribution Networks (Doc 030-2011)
- AS 1384 – Transducers for electrical measurements
- AS 1675 – Current Transformers – Measurement and Protection

4.0 DEFINITIONS AND ABBREVIATIONS

AIM
analogue input module

AIS
analogue input signals

AVR
automatic voltage regulation

CT
current transformer

CT/VT
intelligent current/voltage/power transducer

DCO
double command outputs

DIM
digital input module

DIS
digital input signals

DOM
digital output module

DPI
double point input

Ellipse
Endeavour Energy’s asset database

IED
intelligent electronic device

FT
fault thrower

GIS
gas insulated switchgear

HMI
human machine interface

HV
high voltage. In this document HV refers to equipment located on the primary side of the transformer
I/O
ingput/output

**Legacy**
denoting or relating to software or hardware that has been superseded

LV
low voltage. In this document LV refers to equipment located on the secondary side of the transformer.

**Network**
The Endeavour Energy electrical system of poles, wires, substations and the like by which electrical power is transmitted to customers.

RTU
remote terminal unit

POM
pulsed output module

SAS
substation automation system

**Serial Communication**
includes but is not limited to RS232 and RS485

SCADA
supervisory control and data acquisition

SCO
single command output

SMU
substation management unit

SPI
single point input

TC
tap changer

VDU
visual display unit

VR
voltage regulation

VT
voltage transformer
5.0 ACTIONS

5.1 Safety

5.1.1 General

The design, construction, and commissioning of substation automation systems shall be carried out in accordance with Endeavour Energy’s Health and Safety Management Systems and the Electrical Safety Rules.

Systems shall be implemented and maintained to consider the range of human capacity, both physically and mentally, when designing substation automation systems.

5.2 System overview

A substation automation system (SAS) is a computer based control system that provides monitoring and control facilities of primary plant and other equipment within the Endeavour Energy network.

The SAS provides:

- monitoring of primary plant and equipment by gathering data from various locally connected sources;
- control of connected plant and equipment in both manual and automated modes;
- automating tasks by monitoring systems and executing routines based on analytical processing aligned to network operational requirements;
- a local substation operator interface to the substation automation system, which presents a graphical representation of substation systems and a means of monitoring and controlling connected plant and equipment; and
- remote communications to the SCADA master station for the purposes of remote control and monitoring.

The SAS does not provide:

- explicit and reliable protection functionality, for example, disconnection of fault currents; and
- explicit and reliable equipment operation interlocking functionality, for example, prevention of closing of a circuit breaker onto a faulted section of busbar. Whilst this does not exclude the SAS from issuing a warning or blocking of such an action, the SAS shall not be relied upon to provide this.

5.3 System requirements

The SAS encompasses all of the hardware and software components which together collect input and output signals from primary plant and equipment; process the signals into engineering measurements and indications; intelligently control plant and equipment in software; and communicate the information to other parts of the SAS system and the SCADA master station.
5.3.1 System architecture

The SAS consists of a number of modular components that exchange data to achieve the required system functionality. The modularity of the SAS provides the ability to distribute the components throughout the substation close to source of individual signals. This distributed architecture aims to reduce physical wiring and eliminate SCADA marshalling panels that would be required for a centralised architecture. The distributed architecture consists of:

- the SCADA HMI panel, where the central processing unit (CPU), touch-screen monitor, medical emergency button and SCADA control isolation switch is located;
- the SCADA and communications panel, where the radio, communication gateway or router is located;
- protection relay interfaces via IEC61850 or DNP3.0 communications protocol;
- physical input and output modules, including digital input, digital output, analogue input and intelligent CT/VT modules if required, located within protection and control panels, or the equipment that is being monitored; and
- supporting Ethernet networking infrastructure.

5.3.2 Physical inputs and outputs

Physical input and output modules derive their status and controls from physically connected plant and equipment via digital and analogue input and output modules. The physical modules consist of five types:

- digital input modules (DIMs);
- digital output modules (DOMs);
- pulsed output modules (POMs);
- analogue input modules (AIMs); and
- protection relays with Ethernet communications or Ethernet based intelligent current/voltage/power transducers (CT/VT).

5.3.3 Protection relay communications/interface

Inputs derived from protection relays are signals that are either physically wired to the protection relay, or values calculated internally by the relays. The SCADA system can acquire digital input status and analogue input values from the protection relay communication channel.

Protection relay communications will be used to retrieve:

- analogue values including current, voltage, Watts and VArS;
- fault records; and
- protection related scheme functionality if required, for example, SEF.

Protection relay communications shall not be used for SCADA controls of the primary equipment unless authorised by the SCADA and Program Manager.

Protection relays shall support IEC61850 and have an option for DNP 3.0 over Ethernet. Where a protection relay does not support IEC61850 or DNP 3.0 over Ethernet, approval shall be sought from the SCADA and Program Manager for authorising other protocols or interfaces.

Refer to 5.3.3.1 for wiring requirements for protection relays supporting serial RS485 only.
5.3.3.1 SCADA requirements for protection relays with RS485 serial communications.

Where DNP 3.0 over RS485 serial is the only option available, terminal server devices shall be used to convert the RS485 serial protocol to an IP based protocol for communications with the RTU.

There shall be one protection relay per serial line, which shall be installed within the relay panel.

5.3.4 Automation

Automation routines provide the intelligent processing of the input and output signals gathered by the SAS.

A number of local substation automation routines are required to run within the SAS. The automation routines installed are based on the requirements of the substation, and typically consist of:

- Motorised switch processing and controls – including isolators and earth switches.
- Circuit breaker processing and controls.
- Feeder auto-reclosing.
- Transformer auto standby.
- Tap changer indication and manual voltage/tap controls.
- Automatic voltage regulation.
- Automatic VAr regulation (capacitor controls).
- HV (incoming) feeder restoration (including no volt changeover).
- LV busbar restoration.
- Medical emergency.
- Station load calculations.
- Transducer/CT/VT health monitoring.
- Frequency injection (AFIC) interface.

Note: Signals derived from devices over serial communications are too slow for automation purposes and shall not be used.

5.3.5 Communications

All SAS communication requirements shall comply with those set out in Automation Design Instruction ADI 0006 – Communications in Substations.

Serial communications shall be considered legacy for any time critical application including operation of automation schemes.

Proprietary communication protocols between RTU and SAS equipment shall be avoided and considered legacy.

5.4 Component requirements

5.4.1 Power supplies

5.4.1.1 Voltage level and power source

The nominal supply voltage level for SAS equipment shall be 120V DC and shall be derived from the 120V DC station battery. Wide range power supplies are required to sustain SAS operation during loss of station AC supply or other impact to the 120V DC charging system. (80% to 120%
nominal which may occur if temperature compensated charging systems are employed). All SAS control supplies shall be sourced from dedicated control supplies and not sourced from a protection supply.

5.4.1.2 DC to DC converters

Where SAS equipment does not provide support for the station level 120V DC, an appropriate DC to DC converter shall be used.

5.4.2 Cabling, panels and terminations

All cabling, panels and terminations shall comply with Substation Design Instruction SDI 526 – SCADA Control cabling, panels and terminations.

5.4.3 Input and output signals

5.4.3.1 Digital input modules

Digital input signals shall use a dedicated SAS 120V DC negative through a mechanical contact on an item of substation equipment. Digital inputs shall be capable of operating reliably when driven from between 80% to 120% of nominal 120V DC rating. Digital input impedance shall be low enough to prevent spurious operation from induced currents due to primary equipment operations or other factors (long cable runs etc)

The duration of all input signals shall be constant (not bouncing) for a minimum of 5ms. If equipment contacts cannot achieve this value, pulse prolongation equipment shall be installed.

Double pole digital inputs shall be used for all circuit breaker, motorised switch, disconnector and isolator position status indications (open/close pallets). Earth switch position status indication may use single or double pole digital inputs.

All double pole signals shall be allocated to a pair of terminations beginning on an even input channel (including channel 0). For example, a module with channels numbered 0 through 15 may use double pole signals on channels: 0 and 1; 2 and 3; 4 and 5 and so forth.

The following table describes the conventions that shall apply to all digital input signals.

<table>
<thead>
<tr>
<th>Item</th>
<th>Signal type</th>
<th>Module input</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single pole equipment status</td>
<td>Single pole digital inputs</td>
<td>On/off status Single pole status inputs may be assigned to any channel.</td>
</tr>
<tr>
<td>Circuit breakers / switches</td>
<td>Double pole digital inputs</td>
<td>Closed status Closed and open shall be assigned to consecutive channels in that order, beginning on the even channel (including channel 0).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Open status</td>
</tr>
<tr>
<td>Double pole equipment status</td>
<td>Double pole digital inputs</td>
<td>On status On and off shall be assigned to consecutive channels in that order, beginning on the even channel (including channel 0).</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Off status</td>
</tr>
</tbody>
</table>
5.4.3.2 Digital output modules

Digital output signals, both pulsed and persistent outputs, shall be supplied from the SAS equipment and are derived from the dedicated SAS 120V DC positive. Interposing relays shall be used between the module output contact and the substation equipment if the inrush or steady state current exceeds 200mA at 120V DC. Digital output module relay contacts shall be rated to continuously handle the current draw of the equipment being controlled.

All digital output signals, with the exception of the medical emergency siren control, shall have a common physical isolation point/switch. This SCADA control isolation switch shall be provided on the SCADA HMI panel. The isolation switch physically isolates the supply to the output signals ensuring any controls issued from the SAS will not activate the physical equipment. The isolation switch will have two modes, (1) Supervisory – where all signals operate as expected, (2) Isolated – where all SAS control signals are isolated (with the exception of the medical emergency siren control).

Double pole digital outputs shall be used for bi-state controls such as switch/circuit breaker open and close controls, function on and off controls, and tap changer raise/lower controls.

All double pole outputs shall be allocated to a pair of terminations beginning on an even output channel (including channel 0). For example, a module with channels numbered 0 through 7 may use double pole signals on channels: 0 and 1; 2 and 3; 4 and 5; 6 and 7.

The following table describes the conventions that shall apply to all digital output signals:

<table>
<thead>
<tr>
<th>Item</th>
<th>Signal type</th>
<th>Module output</th>
</tr>
</thead>
<tbody>
<tr>
<td>Single pole equipment control</td>
<td>Single pole pulsed/digital output</td>
<td>Output control</td>
</tr>
<tr>
<td>Circuit breakers / switches</td>
<td>Double pole pulsed/digital outputs</td>
<td>Closed control</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Trip control</td>
</tr>
<tr>
<td>Tap changer</td>
<td>Double pole pulsed/digital outputs</td>
<td>Raise control</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lower control</td>
</tr>
<tr>
<td>Double pole equipment control</td>
<td>Double pole pulsed/digital outputs</td>
<td>On control</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Off control</td>
</tr>
</tbody>
</table>

5.4.3.3 Protection relay interfaces

Signals derived from protection relay interfaces shall be made available via IEC61850 or the DNP 3.0 protocol. The protection relay shall provide analogue values including current, voltage, Watts, VArs. PF and VA are optional inputs when required. If PF and VA are required inputs, but the relay does not provide these measurements, PF and VA can be calculated from Watts and VArs. Where the device does not support IEC61850 or DNP 3.0, approval shall be sought from the SCADA and Program Manager prior to using any other protocol.
All communication interfacing to IED devices shall comply with Automation Design Instruction ADI 0006 – Communications in Substations.

5.4.3.4 **Intelligent CT/VT input modules**

It is the preference to utilise protection relays to provide current, voltage, Watts, and VArs data, however in the absence of capable protection relays, an Ethernet based intelligent CT/VT input module shall be used until compatible relays are installed.

Ethernet based Intelligent CT/VT input modules shall be used for transducing current and voltage where either a CT and/or a VT is connected to the SAS. The intelligent CT/VT input module shall provide current, voltage, Watts, VArs. Watt and VAr values shall be directional (4 Quadrant capable). PF and VA are optional inputs when required. If PF and VA are required inputs, but the relay does not provide these measurements, PF and VA can be calculated from Watts and VArs.

5.4.3.5 **Analogue input modules**

All analogue signals (other than those derived from CT/VT modules or protection relay interfaces) shall use 4 to 20 mA DC signals. The output of the transducers shall be arranged to provide an output of 4mA when the input is at the minimum value (or negative maximum) and 20mA when the input is at the maximum value.

All analogue transducers connected to analogue input modules shall comply with AS 1384 and the requirements of this standard. Transducers shall be of a design that will allow the transducer output to be open circuited, short circuited or loaded in any way without influencing the primary current or voltage. Under abnormal conditions, the transducer shall not generate any output current or voltage that exceeds the rating and could affect the operation of the analogue input module.

Passive transducers shall be given preference and the accuracy required shall be as specified by the class index defined in AS 1384.

5.4.4 **Human Machine Interface (HMI)**

The HMI display facility shall consist of the following minimum requirements:

- a minimum 17" flat panel LCD touch-screen monitor that is 19" rack mountable with a pixel density of at least 1280x1024;
- mouse and keyboard shall be provided with a slide out or retractable door; and
- separate CPU module with sufficient capabilities to run the SAS HMI program(s) and communicate to the SAS system. The CPU module shall have a minimum of:
  - Two USB ports
  - 1 Ethernet LAN port
  - Removable solid state flash card (hard drive)

5.4.5 **Remote Terminal Unit (RTU)**

The RTU racks should be mounted together in the RTU cubicle. The current, voltage and power transducers should be located in a marshalling panel. All cubicle and panels shall have sufficient vermin proofing.
Racks need to be installed in a well-ventilated area as they produce a lot of heat (approx. 50 Watts for each nine [9] slot rack) and need to be supplied with a cool air flow.

### 5.5 Automation functions

The automation functions required from the SAS are as follows:

#### 5.5.1 Remote control

Remote control, alarm and event recording, status and analogue telemetry shall be transmitted to the Master Station via IEC 61850 or the DNP3.0 communications protocol.

#### 5.5.2 Local control

Local control is via a HMI (Human Machine Interface) with either touch-screen or mouse and keyboard interface. The HMI interface shall provide operational control of circuit breakers, motorized switches/isolators, transformer tap controls and auto/non auto status controls.

#### 5.5.3 Event and alarm lists

Status event lists and alarm lists shall be provided via the HMI and displayed in sequence of event time order. A minimum of 100 entries shall be available for each list.

#### 5.5.4 Automation routines and local data processing

The following sections describe the standard SAS automation routines and requirements. Any inputs that are deemed to be necessary for the correct functioning of the SAS automation routines shall be made available to the SAS system. The minimal I/O requirements for SAS systems are set out in Annexure 1.

Additional routines or modifications to standard routines require approval from the SCADA and Program Manager.

##### 5.5.4.1 Standard Automation Routines

The standard automation routines include:

- Auto-Reclose;
- HV Feeder No Voltage Restoration (NVR)/Changeover;
- Transformer Auto-Standby;
- Voltage Regulation;
- Capacitor Control Scheme;
- Station Interrupt; and
- Frequency Injection (AFIC/SILC).

Refer to Annexure 2 for definition and requirements for standard automation routines.

##### 5.5.4.2 Medical emergency

Medical emergency provides a facility for staff within a substation to notify the control room of a medical emergency condition. A push button is located on the substation HMI panel. Once the button has been pressed, the control room acknowledges the medical emergency via the SCADA.
system and a siren is sounded within the substation to notify the staff within the substation that the medical emergency has been accepted and medical emergency procedures are underway.

Inputs and output requirements for the medical emergency routine are the push button input, the siren status input and siren control.

5.5.4.3 **CT/VT health monitoring**

CT/VT health monitoring logic provides the ability to observe the health of three phase CT/VT transducer equipment. By default, the voltage is considered healthy if all phases are greater than 85% of the nominal for more than two seconds. The voltage is considered unhealthy if all phases are less than 10% of the nominal for more than three seconds. The voltage is considered unbalanced if there is greater than 8% of nominal difference between any phases for more than 10 seconds.

5.5.4.4 **Motorised switch processing/controls**

The motorised switch processing and control routines require position status indications (open/close pallets) and plant control outputs (open/close controls). Inputs that indicate plant error, plant fault or automation function blocking conditions (open/close control blocking) shall be provided.

5.5.4.5 **Circuit breaker processing controls**

The circuit breaker processing and control routines require position status indications (open/close pallets), racking/available status and plant control outputs (open/close controls). Inputs that indicate plant error, plant fault or automation function blocking conditions (open/close control blocking) shall be provided.

5.5.4.6 **Manual voltage control (tap changing controls)**

The manual voltage control functions provide voltage raise/lower controls via online transformer tap changing facilities.

The manual voltage control function requires the status and control of all tap changer equipment (tap position indications, tap change in progress, tap changer available and tap changer raise/lower controls) along with any blocking and interlocking signals necessary for tap changing purposes.

5.5.4.7 **Others**

Any non-standard automation routines shall be defined in the Project Definition and provided to the SCADA and Program Manager for approval.

If non-standard automation routines are requested outside of an existing project, a Statement of Network Need will be required to include the delivery of the routine within the appropriate reactive automation program.

**5.6 Primary plant supervision and control requirements**

5.6.1 **Naming conventions**

In order to fully and unambiguously describe each point name defined in the SCADA scanlist and schedules, each name shall include the following components; Network, Plant, Designation, Quantity and States.

For example – “11kV CB 1234 Protection [1=Operated, 0=Restored]”
5.6.2 Minimal I/O requirements

Guides for configuring scanlist I/O for various substation configurations can be found on G:\SCADA\Standards\. Generic scanlist templates are defined and cover the majority of substation configurations within Endeavour Energy.

For customer funded installations there may be additional I/O requirements to be met. These requirements shall be negotiated between Asset Standards and Design, System Control and the connection applicant.

5.6.2.1 Transmission and zone substations

The minimum I/O requirements for transmission and zone substations are set out in Annexure 1.

5.6.2.2 Power Flow Conventions

The power flow conventions are set out in Annexure 3.

5.6.2.3 Generators

Where the customer installation is for connecting a generator having an output capacity of more than 2MVA, the following must be provided to Endeavour Energy through the SCADA system:

- circuit breaker status;
- circuit breaker fail-to-trip alarm;
- MW and MVAr analogue signals; and
- voltages and currents (at the connection point).

If these minimum requirements cannot be meet, approval must be sought from the SCADA and Program Manager.

5.6.2.4 Sub transmission customer funded installations

Where the customer installation is connecting to the sub transmission network, the following must be provided to Endeavour Energy through the SCADA system:

- circuit and switch breaker statuses;
- circuit breaker fail-to-trip alarm;
- voltage, tap position, MW and MVAr analogue signals on transformers that are under Endeavour Energy’s operational control;
- voltage, Amps, MW and MVAr flow on incoming feeders; and
- protection alarms.

If these minimum requirements cannot be meet, approval must be sought from the SCADA and Program Manager.
5.7 Requirements for legacy equipment/communications

5.7.1 Legacy Equipment/Communications

5.7.1.1 Legacy Remote Terminal Unit

An RTU is considered legacy if:

- the model is no longer manufactured, including spare parts;
- it is no longer supported by manufacturer;
- it is no longer under active development by manufacturer (i.e. superseded);
- it does not support IEC61850; and
- it is incapable of supporting any required local control routine/s.

5.7.1.2 Intelligent CT/VT input modules

Whilst the intelligent CT/VT module is not strictly a legacy device, in the event that a protection relay replacement project results in adequate analogue data, the Intelligent CT/VT input module can be considered as legacy, and should be managed as such.

5.7.1.3 Legacy protocol converters

Any device installed to maintain legacy communications protocols including proprietary protection relay protocols.

5.7.1.4 Serial communication

Serial communications used within a SAS shall be considered legacy.

5.7.1.5 Proprietary communications

Proprietary communications used within a SAS shall be considered legacy.

5.7.1.6 Legacy protection relay communications

Protection relays utilising legacy communication protocols over serial to the station RTU shall be considered legacy.

5.7.2 Management of Legacy Equipment/Communications

5.7.2.1 Equipment

When the primary functionality of the legacy equipment can be replaced by newly installed equipment, it should be removed from the installation.

5.7.2.2 Legacy protection relay equipment/communications
When relays utilising legacy communications are replaced during relay replacement projects, all protection relays operating on the legacy communication protocols shall be considered for replacement within the scope of the replacement projects.

If an RTU refurbishment or replacement project requires the installation of additional hardware to maintain proprietary communications with legacy relays, replacement of relays shall be considered within the scope of the project.

5.8 Embedded generator remote supervision and control requirements

5.8.1 Modes of operation

Three (3) modes of operation will be considered for private generating units, namely:

**Non-parallel operation (break before make operation):** Operating in isolation from the supply network by way of a changeover switch. For this type of installation, suitable controlling switchgear is required that can be electrically, mechanically or key interlocked.

**Standby operation (synchronise, close, transfer trip operation - SCTT):** This mode of operation has similar connection arrangements to the non-parallel scheme, except that both the normal supply and generator supply may be connected for a short time in order to allow testing of the generator’s operation and changeover without interrupting the customer’s load.

**Parallel operation:** Connected continuously to the network, with or without the ability to export energy to the grid.

The general operating requirements for the different connection methods are detailed in PDI5000 - Protection of embedded generation systems. Detailed operating arrangements will be negotiated for each case and included in the operating agreement between the customer and Endeavour Energy.

5.8.2 Requirements

The following table details which generator applicants may require remote monitoring and control equipment:

<table>
<thead>
<tr>
<th>Mode</th>
<th>Size</th>
<th>Remote supervision and control requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Non-parallel</td>
<td>All</td>
<td>Not required</td>
</tr>
<tr>
<td>operation</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Standby operation</td>
<td>&lt; 5 MW</td>
<td>Not required</td>
</tr>
<tr>
<td></td>
<td>≥ 5 MW</td>
<td>Remote monitoring and control equipment may be required for remote operational purposes and load or voltage control.</td>
</tr>
<tr>
<td>Parallel operation</td>
<td>&lt; 2.5 MW</td>
<td>Not required</td>
</tr>
<tr>
<td></td>
<td>≥ 2.5 MW</td>
<td>Remote monitoring and control equipment may be required for remote operational purposes and load or voltage control.</td>
</tr>
</tbody>
</table>

This requirement will be negotiated for each situation, as any such requirements depend on the relative capacities of the generator and grid at the connection point. Should it be deemed that the embedded generator requires remote control and supervision; the generator applicant must provide the following:

- communications as per section 5.8.2.1;
• minimum I/O as per section 5.8.2.2;
• SCADA equipment that complies with IEC 61850;
• an RTU compatible with Endeavour Energy’s SCADA system;
• wiring connection schedule for the RTU;
• software development for the RTU and the master station; and
• testing and commissioning of all of the above.

There may be additional requirements to be met. These requirements shall be negotiated between Asset Standards & Design, System Control and the connection applicant.

5.8.2.1 Communication requirements

A communication medium between the generator premises and Endeavour Energy’s control centre is required in order to send and receive data. If remote inter-tripping is required to Endeavour Energy’s installation, the preferred option is for a dedicated optical fibre link. Alternatives include a dedicated copper wire link and UHF radio or, if no other option is practical, a leased telecommunications circuit. The reliability of leased links can be very poor. Generation may be inhibited while the link is out of service, but supply of power to the customer’s installation will not be interrupted.

The choice of communication medium shall be negotiated between Asset Standards & Design and the generator applicant. Communication equipment shall be installed in accordance with ADI 0006 - Communications in Substations.

5.8.2.2 Minimum I/O requirements

• status indication on all relevant Circuit Breakers;
• circuit breaker fail-to-trip alarms;
• protection operation alarms;
• analogue indication of 3-phase Current, voltage, active power and reactive power; and
• protection operation alarms.

There may be additional I/O requirements to be met. These requirements shall be negotiated between Asset Standards & Design, System Control and the connection applicant.

5.9 Customer funded installation supervision and control requirements

Where the customer installation is connecting to the sub transmission network, the requirement for supervision and control will be negotiated for each situation. The requirements will depend on the total customer load and grid at the connection point. Should it be deemed that the customer installation requires remote control and supervision; the generator applicant must provide the following:

• status indication on all relevant Circuit Breakers;
• circuit breaker fail-to-trip alarms;
• protection operation alarms;
• analogue indication of 3-phase Current, voltage, active power and reactive power on transformers that are under Endeavour Energy’s operational control;
• analogue indication of 3-phase Current, voltage, active power and reactive power on all incoming feeders; and
• low battery/battery warning alarms.
There may be additional I/O requirements to be met. These requirements shall be negotiated between Asset Standards & Design, System Control and the connection applicant.

6.0 AUTHORITIES AND RESPONSIBILITIES

**General Manager Asset Management** has the authority and responsibility for approving this instruction.

Manager Asset Standards and Design has the authority and responsibility for:

- making recommendations to the GM Asset Management in respect to this instruction; and
- approving minor amendments to this instruction.

**Communications and Control Manager** and **SCADA and Program Manager** have the authority and responsibility for:

- keeping the content of this instruction up to date based on industry best practice; and

**Substation Secondary Design Manager** has the authority and responsibility for verifying that the requirements of this instruction are adhered to in the design and construction of substation communication systems.

**Endeavour Energy staff and/or contractors** have the authority and responsibility for:

- verifying that the requirements of this instruction are met;
- working in accordance with local and statutory requirements; and
- working in accordance with Endeavour Energy’s Electrical Safety Rules.

**Regional Transmission Managers** have the authority and responsibility for:

- meeting the requirements of this instruction within their area of responsibility; and
- verifying that Endeavour Energy employees and/or contracts engaged to perform the work have appropriate qualifications.

7.0 DOCUMENT CONTROL

**Documentation content coordinator:** Communications and Control Manager

**Documentation process coordinator:** Standards Process Coordinator
## ANNEXURE 1: TRANSMISSION AND ZONE SUBSTATION I/O REQUIREMENTS

<table>
<thead>
<tr>
<th>Item</th>
<th>Signal type</th>
<th>SAS inputs</th>
<th>Source</th>
<th>Option</th>
</tr>
</thead>
<tbody>
<tr>
<td>HV Feeders</td>
<td>AI</td>
<td>Line-to-line voltage (A-B, B-C, C-A)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Current (A, B, C)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MW, MVAr</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MVA, Pf</td>
<td>Relay [1] or CT/VT</td>
<td>O [3]</td>
</tr>
<tr>
<td>LV Feeders (with less than 2 MVA of embedded generation)</td>
<td>AI</td>
<td>Line-to-line voltage (A-B, B-C, C-A)</td>
<td>Relay [1] or CT/VT</td>
<td>O</td>
</tr>
<tr>
<td></td>
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<td>Current (A, B, C)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
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<tr>
<td></td>
<td></td>
<td>MW, MVAr</td>
<td>Relay [1] or CT/VT</td>
<td>O [2]</td>
</tr>
<tr>
<td></td>
<td></td>
<td>MVA, Pf</td>
<td>Relay [1] or CT/VT</td>
<td>O [3]</td>
</tr>
<tr>
<td>LV Feeders (with equal to or greater than 2 MVA of embedded generation)</td>
<td>AI</td>
<td>Line-to-line voltage (A-B, B-C, C-A)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
</tr>
<tr>
<td></td>
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<td>Current (A, B, C)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
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<td></td>
<td></td>
<td>MW, MVAr</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
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<tr>
<td></td>
<td></td>
<td>MVA, Pf</td>
<td>Relay [1] or CT/VT</td>
<td>O [3]</td>
</tr>
<tr>
<td>Transformer bay (HV side)</td>
<td>AI</td>
<td>Line-to-line voltage (A-B, B-C, C-A)</td>
<td>Relay [1] or CT/VT</td>
<td>O</td>
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<tr>
<td></td>
<td></td>
<td>Current (A, B, C)</td>
<td>Relay [1] or CT/VT</td>
<td>M</td>
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<td></td>
<td>MW, MVAr</td>
<td>Relay [1] or CT/VT</td>
<td>O [2]</td>
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<tr>
<td>Item</td>
<td>Signal type</td>
<td>SAS inputs</td>
<td>Source</td>
<td>Option</td>
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<tr>
<td>Transformer bay (LV side)</td>
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<td>Line-to-line voltage (A-B, B-C, C-A)</td>
<td>Relay [3] or CT/VT</td>
<td>M</td>
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<tr>
<td></td>
<td></td>
<td>Current (A, B, C)</td>
<td>Relay [3] or CT/VT</td>
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<td>MW, MVAR</td>
<td>Relay [3] or CT/VT</td>
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<tr>
<td></td>
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<td>MVA, Pf</td>
<td>Relay [3] or CT/VT</td>
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<tr>
<td>Bus sections</td>
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<td>Line-to-line voltage (A-B, B-C, C-A)</td>
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</tr>
<tr>
<td></td>
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<td>Current (A, B, C)</td>
<td>Relay [3] or CT/VT</td>
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<tr>
<td>GIS equipment</td>
<td>DI</td>
<td>Low SF6</td>
<td>IO</td>
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<td></td>
<td></td>
<td>Low SF6 stage 1 alarm for GIS equipment</td>
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<td></td>
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<td>Low SF6 stage 2 alarm for GIS equipment</td>
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<td>Circuit breakers</td>
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<td>Closed status</td>
<td>IO</td>
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<td></td>
<td></td>
<td>Open status</td>
<td>IO</td>
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<tr>
<td></td>
<td></td>
<td>Available/racking status</td>
<td>IO</td>
<td>M</td>
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<td>Earthed status</td>
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<td>Low pressure alarm</td>
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<td></td>
<td>DO</td>
<td>Close control</td>
<td>IO</td>
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<td></td>
<td></td>
<td>Trip control</td>
<td>IO</td>
<td>M</td>
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<tr>
<td>Auxiliary transformer</td>
<td>DI</td>
<td>Supply failure</td>
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<tr>
<td>Power transformer</td>
<td>DI</td>
<td>Buchholz main tank alarm</td>
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<td></td>
<td></td>
<td>Buchholz relay trip – main tank</td>
<td>IO</td>
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<td></td>
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<td>Buchholz TC alarm</td>
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<td></td>
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<td>Buchholz relay trip - TC</td>
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<td>Cooler control AC supply failure</td>
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<td>Cooling fan failure</td>
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<td>Cooling fan status (on, off)</td>
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<td>Cooling fan switch status (auto/manual)</td>
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<td>Item</td>
<td>Signal type</td>
<td>SAS inputs</td>
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<td>Option</td>
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<td>Oil pump status (on, off)</td>
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<td>Pump switch status (auto, manual)</td>
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<td>Temperature alarm (common oil and winding)</td>
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<tr>
<td>Temperature trip (common oil and winding)</td>
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<td>Oil temperature</td>
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<td>Tap changer</td>
<td>DI</td>
<td>Buchholz relay trip – (tap changer)</td>
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<td>Main supply failure</td>
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<td>Tap changer available</td>
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<td>Tap changer cam switch (t/c in progress)</td>
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<td>Tap position LSB</td>
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<td>Tap position Bit 2</td>
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<td>Tap position Bit 4</td>
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<td>Tap position Bit 8</td>
<td>IO</td>
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<tr>
<td>Tap position MSB</td>
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<tr>
<td>Lower</td>
<td>DO</td>
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<tr>
<td>Raise</td>
<td>IO</td>
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<td>Protection signals</td>
<td>DI</td>
<td>Refer to protection and indication schedules</td>
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<td>SEF Auto/Non Auto status for substation</td>
<td>IO</td>
<td>M</td>
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<tr>
<td>SEF protection operation for each breaker</td>
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<tr>
<td>Maximum fault current</td>
<td>AI</td>
<td>Relay</td>
<td>O</td>
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<tr>
<td>Distance to fault</td>
<td>AI</td>
<td>Relay</td>
<td>O</td>
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<tr>
<td>SEF auto/non auto for substation</td>
<td>IO</td>
<td>M</td>
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<td>Substation batteries</td>
<td>IA</td>
<td>Battery terminal voltage</td>
<td>IO</td>
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<tr>
<td>DI</td>
<td>AC supply failure</td>
<td>IO</td>
<td>M</td>
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<tr>
<td>Battery earth fault</td>
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<tr>
<td>Battery hi/lo volts</td>
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<td>O</td>
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<td>General battery alarm</td>
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<td>Frequency injection</td>
<td>DI</td>
<td>General alarm</td>
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<td>FI control status (avail/unavail)</td>
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<td>FI keying contactor status</td>
<td>IO</td>
<td>M</td>
<td></td>
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<tr>
<td>FI run injection alert</td>
<td>IO</td>
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<td>FI street lights off</td>
<td>IO</td>
<td>M</td>
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<td>FI street lights on</td>
<td>IO</td>
<td>M</td>
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<tr>
<td>Item</td>
<td>Signal type</td>
<td>SAS inputs</td>
<td>Source</td>
<td>Option</td>
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<td></td>
<td>FI voltage supervision</td>
<td>IO M</td>
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<td></td>
<td>DO FI alert output (motor contactor)</td>
<td>IO M</td>
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<td></td>
<td>FI keying output (impulse contactor)</td>
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<tr>
<td>Radio, communications</td>
<td>DI Radio battery hi/lo volts</td>
<td>IO O</td>
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<td></td>
<td>DI Radio battery AC failure</td>
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<td></td>
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<td></td>
<td>DI Receiver failure</td>
<td>IO O</td>
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<tr>
<td></td>
<td>DI Transmitter failure</td>
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<td></td>
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<tr>
<td>Supervisory control</td>
<td>DI Status of output control switch</td>
<td>IO M</td>
<td></td>
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<td>Medical emergency</td>
<td>DI Button</td>
<td>IO M</td>
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<td></td>
<td>DI Siren status</td>
<td>IO M</td>
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<td></td>
<td>DO Start siren</td>
<td>IO M</td>
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<tr>
<td>Security system alarms</td>
<td>DI Status</td>
<td>IO M</td>
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<tr>
<td></td>
<td>DI Alarm</td>
<td>IO M</td>
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<td></td>
<td>DI Equipment failure alarm</td>
<td>IO M</td>
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<td>Fire detection system</td>
<td>DI Status</td>
<td>IO M</td>
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<td></td>
<td>DI Alarm</td>
<td>IO M</td>
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<tr>
<td></td>
<td>DI Equipment failure alarm</td>
<td>IO M</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

M = Mandatory
O = Optional – to be installed if available

See Annexure 3 for power flow conventions.

Notes:
1. It is the preference to ensure analogues are available via the protection relay;
2. SAS inputs are optional if unavailable, for example:
   a. protection relays do not support Ethernet communication, and
   b. both VTs and CTs are unavailable to be connected to an intelligent CT/VT module.
3. If MVA and pf are required, and the source is only capable of sending MW and MVAr, then MVA and pf will be calculated within the substation RTU.
ANNEXURE 2: STANDARD SCHEME DEFINITIONS AND REQUIREMENTS

Auto-Reclosing

Definition

Feeder auto-reclose monitors the state of feeder circuit breaker. If a protection operation occurs on the feeder, the scheme attempts to close the circuit breaker online after a short pre-determined delay to restore supply. Auto-reclose functionality is used on overhead feeders where the likelihood of a transient fault is high.

In general, feeders can be classified into one of two categories; (1) Source feeders (provides supply to the line) and (2) Receiving feeders (receives supply from the line). The majority of feeders within Endeavour Energy substations are source feeders.

In some cases, transmission feeders may require the option of being dynamically configured as a source feeder or a receiving feeder depending on the switching arrangements of the transmission network. In order to cater for these dynamic auto-reclosing requirements, transmission feeders may be configured to provide three modes of operation (tri-mode auto-reclose). The three modes of operation are:

1. **Dead Line Charge (DLC)**
   For source feeders where closing the feeder’s circuit breaker will supply (charge) a dead line.

2. **Live Line Check (LLC)**
   For receiving feeders where closing the feeder’s circuit breaker will provide supply to the busbar.

3. **Non-Auto**
   Disable the auto-reclosing functionality of the feeder.

The majority of Endeavour Energy feeders are of a fixed type and only require a simple Auto/Non-Auto point to enable or disable auto-reclosing functionality. Transmission feeders may require the three modes of operation and the ability to remotely select the mode of operation. For these types of feeders, tri-mode auto-reclose provides the dynamic configuration requirements.

Hardware Requirements

- Feeder CB status and control inputs
- Digital triggering inputs (such as protection operations)
- Blocking inputs (such as busbar protection operations)
- Where tri-mode auto-reclose (DLC/LLC) is required, high speed 3 phase voltage indications are required on both the line side of the feeder, and on the busbar where the feeder is attached to. Voltage values are required < 1 second.

<table>
<thead>
<tr>
<th>Suitable Sources</th>
<th>Unsuitable Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethernet based intelligent transducers</td>
<td>RS232, RS485 based intelligent transducers (for example, ABB CVDs)</td>
</tr>
<tr>
<td>Values from protection relays via Ethernet communications</td>
<td>Values from protection relays via RS232, RS485 communications</td>
</tr>
<tr>
<td>Transducer values via SCADA based analogue input modules</td>
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</table>

<table>
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</tr>
<tr>
<td>Transducer values via SCADA based analogue input modules</td>
<td></td>
</tr>
</tbody>
</table>
Configuration Requirements

- Trigger conditions (usually feeder protection operations)
- Blocking conditions (for example, recent busbar protection operations)
- Number of shots (number of auto-reclose attempts to try before giving up – usually just 1 attempt)
- Dead time delay (dead/settling time before attempting an auto-reclose operation)

HV Feeder No Voltage Restoration (NVR)/Changeover

Definition

No voltage restoration monitors the voltages of the incoming feeders, and if a loss of supply is detected on the in-service feeder, the scheme attempts to resupply supply the substation after a short pre-determined delay. Other trigger conditions, such as a protection operation can also be incorporated into the triggering conditions of this scheme.

No voltage restoration also has a chargeback feature which, if appropriate, will close the secondary CB to resupply the downstream substation at the other end of the feeder.

1. No Voltage Restoration/Changeover Functionality

Given the example below, if a loss of supply is detected on VT 1 (FDR 1), the following steps occur:

1. Open CB 1 (if it wasn’t already opened due to a protection operation of the feeder)
2. Wait for a short pre-determined delay – usually 10 seconds (allow upstream restoration schemes to operate)
3. If VT 1 supply is healthy, Close CB 1 (restores supply to the previous state)
4. If VT 1 supply is unhealthy, but VT 2 supply is healthy, Close CB 2 (restores supply via alternate feed) [show in example below]

![Diagram showing NVR/Changeover Functionality](image)

Prior to NVR operation

Post NVR operation

NOTE: The standard no voltage restoration only provides monitoring of two feeders.

2. Chargeback Functionality

Given the example below, if a loss of supply is detected on VT 2 at substation 1, the following steps occur:

1. Wait for a short pre-determined delay – usually 10 seconds (allow upstream restoration schemes to operate)
2. If VT 2 supply at Substation 1 is healthy, do nothing
3. If VT 2 supply at Substation 1 remains unhealthy, Close CB 2 at Substation 1 (restore supply to Substation 2 via Substation 1 HV Busbar/Feeders)
Hardware Requirements

- HV Feeder CB status and control inputs
- Digital triggering inputs (such as protection operations)
- Blocking inputs
- High speed 3 phase voltage indications (line side of feeders) on both incoming feeders. Voltage values are required < 1 second.

<table>
<thead>
<tr>
<th>Suitable Sources</th>
<th>Unsuitable Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ethernet based intelligent transducers</td>
<td>RS232, RS485 based intelligent transducers (for example, ABB CVDs)</td>
</tr>
<tr>
<td>Values from protection relays via Ethernet communications</td>
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<tr>
<td>Transducer values via SCADA based analogue input modules</td>
<td></td>
</tr>
</tbody>
</table>

Configuration Requirements

- Trigger conditions (usually loss of all 3 phases on in-service feeder)
- Blocking conditions (for example, recent busbar protection operations)
- Restoration time delay (settling time before attempting a restoration operation)
- Chargeback requirements (which feeders require chargeback functionality)
- Chargeback time delay (settling time before attempting a chargeback operation)
Transformer Auto Standby

**Definition**

Transform auto-standby monitors the state of all online transformers at the substation. If an internal protection fault occurs on one of the transformers, the scheme attempts to close a standby transformer online to restore capacity to the substation. Generally speaking, this scheme is used to restore capacity to a low voltage busbar after loss of an in-service transformer due to a fault.

There are many substation topologies and operational configurations that the transformer auto-standby scheme must take into consideration. Primarily, the standard scheme only works by simply closing a standby transformer online to resupply capacity to the substation – no further CB operations are executed (such as LV busbar rearrangements).

If any low voltage (or high voltage) busbar rearrangements are required to restore capacity to the substation, then additional functionality must be defined and developed. The transformer auto-standby scheme allows for this additional functionality to be added where necessary, but must be thoroughly defined, reviewed and agreed upon prior to commencing any of the additional development works.

The following diagram shows an example of a successful auto-standby operation. The diagram on the left shows the substation prior to any auto-standby operation occurring (normal substation operating configuration). The diagram on the right shows the substation after an internal fault on T1 has occurred and a successful auto-standby operation.

![Diagram of substation showing auto-standby operation](image)

**Hardware Requirements**

- All transformer CB status and control inputs
- Digital triggering inputs (such as transformer protection operations)
- Blocking inputs (such as busbar protection operations)
- Where loss of supply to an online transformer is required as a trigger, high speed 3 phase voltage indications are required on the low voltage side of the transformer. Voltage values are required < 1 second.
### Suitable Sources
- Ethernet based intelligent transducers
- Values from protection relays via Ethernet communications
- Transducer values via SCADA based analogue input modules

### Unsuitable Sources
- RS232, RS485 based intelligent transducers (for example, ABB CVDs)
- Values from protection relays via RS232, RS485 communications

### Configuration Requirements
- Trigger conditions (usually internal transformer protection operations)
- Blocking conditions (for example, recent busbar protection operations)
- Any additional restoration requirements (for example, LV busbar rearrangements post standby operations)
Voltage Regulation

Definition

The Voltage Regulation scheme is responsible for maintaining the voltage level within defined limits on the low voltage busbar within a substation. This is achieved by continually monitoring the actual (feedback) voltage levels and comparing them with the required levels. If the actual voltage levels are outside of the required limits for a period of time, the voltage regulation scheme will initiate appropriate tap raise or lower controls depending on the current voltage level.

The VR scheme can be configured to regulate the transformers individually or configured to regulate the transformers in a parallel group.

1. Individual Regulating Transformers

The standard voltage regulation scheme allows each transformer to regulate the voltage levels independent of the other transformers. Each transformer can have its own set of operating configurations, such as float levels, tap ranges, load drop compensation, etc.

The diagram below shows a typical substation configured so all transformers are regulating individually.

![Diagram of Voltage Regulation Scheme]

2. Parallel Group Regulating Transformers (Master Follower Regulation)

The master-follower implementation of the voltage regulation scheme allows for transformers to be grouped and regulated as a single group. In a master-follower type of arrangement, one of the transformers (usually the first transformer) assumes the role of master, and regulates itself by maintaining the desired float level. All other transformers in the group are follower transformers and simply follow the master transformer tap.
The scheme allows for transformers with different tap numbers and ranges to be regulated in parallel groups by defining an equivalent tap lookup table. As the master transformer raises or lowers its tap changer, the follower transformers refer to the lookup table to find their equivalent tap and raise or lower their tap changer as required.

The following diagram shows a typical configured to regulate as a parallel group.

**Hardware Requirements**

- All transformer CB status inputs
- All transformer tap changer inputs and controls
- High speed 3 phase voltage indications are required on the low voltage side of all transformers. Voltage values are required < 1 second.

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**Configuration Requirements**

- Nominal Float Voltage Level
- Trigger Percentage (usually 1.5 %)
- Hysteresis Percentage (usually 1%)
- Out of Range Percentage (usually 20%)
- Maximum Delay Time (usually 90 seconds)
- Blocking conditions
Capacitor Control Scheme

Definition

The Capacitor control scheme is responsible for minimising the reactive losses (MVAr) within the substation. This is achieved by continually monitoring the total reactive losses (MVAr) of all online transformers within the substation, and comparing them against the acceptable limits. If the losses are outside the accepted limits for a period of time, the capacitor control scheme will initiate the appropriate switching of capacitors into or out of the system depending on the current reactive losses.

Hardware Requirements

- All capacitor switch status inputs and controls
- All capacitor/auxiliary CB status associated with the capacitor control scheme
- Capacitor available inputs (this may simply be auxiliary CB status inputs)
- High speed MVAr values of all transformers. MVAr values are required < 1 second.

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Configuration Requirements

- Station MVAr Threshold Level
- Maximum Delay Time (usually 900 seconds – 15 minutes)
- Capacitor Bank Availability logic (what logic determines the capacitor bank is available to the scheme)
- Blocking conditions
- Capacitor discharge timeout (usually 300 seconds – 5 minutes)
Station Interrupt

Definition

The station interrupt scheme is an operational support scheme that monitors the voltage levels on all transformers at the substation. If the scheme detects that all transformers have lost volts, an alarm is generated for the system operators indicating a total loss of supply to the substation.

Hardware Requirements

- 3 phase voltage indications are required on the low voltage side of all transformers.

Configuration Requirements

- No configuration requirements

Frequency Injection (AFIC/SILC)

Definition

SILC (SCADA Integrated Load Control) is responsible for turning on and off loads such as off-peak hot water systems, pool pumps, irrigation systems and street lighting. It is a time-based system that controls the signals that are injected onto the distribution feeder network to communicate with frequency injection relays installed on the system.

Hardware Requirements

- Motor generator or static frequency unit input status and control
- Keying contactor input status and controls
- SILC availability inputs
- Injection supervision checkback signals (for example, voltage or current supervision signals)
- Photo Cell inputs (for street light controls)

Configuration Requirements

- Frequency Injection program (time based program for substation)
- SILC Cell Availability logic (what logic determines the SILC cell is available to the scheme)
### ANNEXURE 3: POWER FLOW CONVENTIONS

The table below shall be used for power flow conventions.

<p>| | |</p>
<table>
<thead>
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</tr>
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<tr>
<td><strong>Real power</strong></td>
<td>MW flowing <strong>into</strong> a busbar is positive. MW flowing <strong>out of</strong> a busbar is negative.</td>
</tr>
<tr>
<td><strong>Reactive power</strong></td>
<td>Capacitive MVAr is positive (supplying reactive power). Inductive MVAr is negative (consuming reactive power).</td>
</tr>
<tr>
<td><strong>Transformers</strong></td>
<td>MW and MVAr flowing from <strong>HV to LV</strong> busbar is positive. MW and MVAr flowing from <strong>LV to HV</strong> busbar is negative.</td>
</tr>
</tbody>
</table>

The following diagram illustrates these principles. For simplicity transformer losses have been ignored.

![Power Flow Diagram](image)