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Functional Specification

110/220/400 kV Control, Protection and Metering

Revision History					
Revision	**Date**	**Description**	**Originator**	**Checker**	**Approver**
R0	08/09/2011	First Issue – This document supersedes XDS-WTS-06-001-R0. This functional spec covers 110kV, 220kV and 400kV. Section 4, 6 and 9 updated. New chapters 13, 14 & 15 by Cathal Kearney	Paul Moran	-	Christy Kelleher
R1	29/05/14	Minor revisions to sections 3, 4, 5, 7, 8, 9, 11 and 13	Sandra Howard	-	Paul Moran
R2	22/12/2020	Comprehensive review and update	Kelvin McGurk	Due-diligence process and Conor Farrell	Brendan Murray

Contents

1 SCOPE

The following specification covers the control & protection and metering requirements for 110 kV, 220 kV & 400 kV transmission substations. The specification covers the requirements for AIS and GIS installations with RTU and SCS applications.

This specification covers assets that will come under the control of the Transmission System Operator (TSO) and does not necessarily apply to all substations or assets under the control of the Distribution System Operator (DSO). Particular care should be taken in installations where both TSO and DSO requirements may apply.

The document describes in detail the required functionality of High Voltage switchgear operation, control and indication. Metering, signalling, alarms, interface requirements and the fundamental protection systems are included.

This specification applies to all new substations. For works in existing substations, this specification may be used as a guide, but due care shall be exercised to ensure consistency and compatibility with legacy conventions or practices which may be contrary to this specification.

For the purposes of this specification the definitions of panel, cabinet and enclosure shall be considered interchangeable. For details of the specific physical requirements for each refer to functional specification XDS-GFS-07-001.

1.1 ABBREVIATIONS AND DEFINITIONS

The following commonly applicable abbreviations are used throughout this document:

Abbreviation	Definition
AAP	Alarm Annunciator Panel.
AC	Alternating Current
AFR	Auto Frequency Restoration
AIS	Air Insulated Switchgear
BCP	Bay Control Point
BCU	Bay Control Unit
BESS	Battery Energy Storage System
BNC	Bayonet Neill-Concelman connector
CB	Circuit Breaker
CT	Current Transformer
DC	Direct Current
DRR	Dispersed Relay Room
DSO	Distribution System Operator (ESB).
ECC	Emergency Control Centre (TSO)
ETIE	EirGrid Telecoms Interface Enclosure
GIS	Gas Insulated Switchgear
GSA	General Station Alarm
HMI	Human Machine Interface

Abbreviation	Definition
HRC	High Rupturing Capacity (Fuse)
HV	High Voltage
ICP	Integrated Control and protection
IED	Intelligent Electronic Device
LCC	Local Control Cabinet
LIPL	Lightning Impulse Protection Level
LOTO	Lock Out tag Out. Operational safety procedure to control isolation of plant.
MCB	Miniature circuit breaker
MRE	Maintenance, repair and extension
MTBF	Mean time between failures
N/O	Normally open
N/C	Normally closed
NCC	National Control Centre (TSO)
NDCC	National Distribution Control Centre (DSO)
OEM	Original Equipment Manufacturer
OLTC	On Load Tapchanger
PCP	Plant Control Point
PD	Partial Discharge
RCP	Remote Control Point
RTU	Remote Terminal Unit. Commonly used to differentiate substations with this hardwired type of control interface.
SAS	Substation Automation System
SCS	Substation Control System. Commonly used to differentiate substations with this digital communication type of control interface.
SF6	Sulphur Hexafluoride
SLD	Single Line Diagram
SCP	Substation Control Point
TEV	Transient enclosure voltage
TRV	Transient recovery voltage
TSO	Transmission System Operator (EirGrid)
UHF	Ultra-high frequency
VFTO	Very fast Transient Overvoltage
VT	Voltage Transformer
Other terminology or common legacy naming is clarified as appropriate throughout the document.	

1.2 SWITCHES

The following general principles provide guidance for the requirements of various types of operation. In case of doubt, clarification can be sought from the EirGrid Client Engineer.

1.2.1 CONTROL ISOLATION SWITCH

This shall be a 2 position (On/Off) switch and shall disable a particular circuit or function and provide a point of isolation. These switches shall be capable of being padlocked in the off position. Examples are "Master Remote On/Off" switch in NCC RTU or SLC cabinet, individual plant "Control On/Off" switches at bay or plant control point.

The standard convention of vertical for "off" and clockwise rotation (60 or 90 degrees) towards horizontal for "on" shall apply.

1.2.2 OPERATIONAL RELEASE KEY SWITCH

A conditional "stop and think" facility to increase operator safety on particular operations.
These shall be 2 position spring return key switches arranged that the key can only be inserted and removed in the "off" or "locked" position.
An example is the additional earth unlock key switch release which shall be provided at all operating points for any earthing switch which could be energised from a remote source (i.e. a remote TSO substation or a remote customer MV substation).

1.2.3 COMMAND SWITCH

This switch[1] is used to issue a manual open or close command to a particular item of plant. Command switches shall be multiple action type (i.e. turn, push and turn).
The switch may be dual purpose (e.g. Open & Close) but shall be a transient spring return type (i.e. spring return from the command issuing position).
Illuminated command & discrepancy type shall be used in the Substation control cabinet and Local Control Cabinet.
The use of single action non latched push button command switches shall only be permitted by agreement (examples are tapchanger "Raise/Lower" or for consistency at legacy substations).
Command switches shall be fitted with suitable means for securing against unintentional operation. These shall be easily removable and shall prevent operation but not inhibit the view of the status of the switch when in place. The device shall not be capable of being propped or otherwise held in an open position and shall need to be removed to allow operation. Such securing devices shall be suitably sized for the respective command switch.
The use of "cups", held in place magnetically, shall generally be considered acceptable; however alternative arrangements may be accepted subject to formal agreement with EirGrid.

[1] Also commonly referred to as a control and discrepancy or SMD switch.

Figure 1 - Example of command switch “cups"

1.2.4 CONTROL SELECTION SWITCH (ROTARY)

This shall be a rotary switch used to select between 2 or more modes or points of operation. The contacts (Normally open/closed, early/late making & breaking etc.) shall be determined by the specific application, but shall not open circuit CT circuits, short circuit or parallel VT circuits or simultaneously provide conflicting selection condition.
Examples are bay control “Remote/Local” and protection relay “Normal/Trip Off/Test”.

1.2.5 CONTROL SELECTION SWITCH (PUSHBUTTON)

This shall be a push button switch used to select or support a particular operation or circuit. These shall be latched or unlatched and illuminated or not depending on the particular application.
Examples are the synchronising “direct close“, “sync close”, and control sync close bay selection pushbuttons.

1.2.6 ACKNOWLEDGE/ALERT PUSHBUTTONS

Non latching push button switches shall be provided as determined by the specific application.
Where required the buttons shall have an additional flap to prevent unintended operation.
Examples are “Blue alert acknowledge”, “Lamp test” and “Emergency telephone”.

1.2.7 INTERLOCK BYPASS SWITCH

These shall be 2 position key switches arranged that the key can only be inserted and removed in the “off” or “locked” position.
The switch shall be clearly labelled “Interlock bypass” and the 2 positions shall be labelled “Normal” and “Bypassed”.
These shall only be installed in the LCC in SCS installations.
Keys shall be interchangeable within all bays of a substation.

2 STANDARDS

All installations shall comply with the latest version of the Grid Code. The Irish Grid Code is available on the EirGrid website www.eirgridgroup.com.

Except where otherwise stated in the functional specification, materials shall be designed, manufactured, tested and installed according to relevant IEC/EN standards. Where applicable the Irish adaptation of the standard (IS EN version), including any national normative aspects, shall apply.
Where no IEC/EN standards have been issued to cover a particular subject a recognised international standard shall be applied.

The latest revisions of the following standards shall apply:

IEC 50288	Multi element metallic cables used in analogue and digital communication and control
IEC 60060	High Voltage Test Techniques (all parts)
IEC 60068	Environmental testing
IEC 60227	Polyvinyl chloride insulated cables of rated voltages up to and including 450/750V
IEC 60255	Electrical relays
IEC 60297	Mechanical structures for electronic equipment (all relevant parts)
IEC 60445	Basic and safety principles for man-machine interface, marking and identification
IEC 60529	Classification of degrees of protection provided by enclosures
IEC 60617	Recommended graphical symbols
IEC 60870	Telecontrol equipment and systems
IEC 60874	Fibre optic interconnecting devices and passive components
IEC 60917	Modular order for the development of mechanical structures for electronic equipment practices
IEC 60947	Low voltage switchgear and controlgear (All relevant parts)
IEC 61000	Electromagnetic compatibility (All relevant parts)
IEC 61082	Preparation of documents used in electrotechnology
IEC 61439	Low voltage switchgear and controlgear assemblies
IEC 61554	Panel mounted equipment – Electrical measuring instruments - Dimensions for panel mounting
IEC 61850	Communication networks and systems in substations
IEC 61869	Instrument transformers (all relevant parts)
IEC 61936	Power installations exceeding 1 kV a.c.
EN 50110	Operation of electrical installations – General requirements
EN 60051	Direct acting indicating analogue electrical measuring instruments and their accessories
EN 62262	Degrees of protection provided by enclosures
IEEE C37.2	Standard electrical Power System Device Function Numbers and Contact Designations (ANSI)
ES1 12-1	Terminal Blocks
BS 142	Electrical protection relays
VDE 0410	Direct recording electrical measuring instruments
DIN 43700	Cases and panel cut-outs for indicating instruments and associated equipment

DIN 43802	Scales and pointers for electrical measuring instruments
ET103: 2015	National rules for electrical installations – Power installations exceeding 1 kV a.c
I.S. 10101	National Rules for Electrical Installations.

In the case of conflict between this specification and any of the listed standards, this specification shall take precedence, however the Customer may seek a clarification to any conflict if necessary.

This specification shall be read in association with all other relevant EirGrid Functional Specifications.

In addition, there shall be compliance with the provisions of all relevant Directives of the European Communities relating to work equipment, i.e. in regard to safety of personnel who operate and maintain the equipment. In order to prove compliance, the equipment shall carry the CE Mark (where required) in accordance with Direction 93/465/EEC.

2.1 Reference documents

The customer shall also refer to all associated functional specifications and documents including the latest version[2] of the documents listed in
Table 11 below.

Table 1: Reference documents

Document no./ref	Title	Owner & type
XDN-CR-STND-H-001	Indicative Control room layout	EirGrid Design Standard Drawing
XDS-DELS-00-004	Electrical Schematic NCC Blue Alert	EirGrid Design Standard Drawing
XDS-DELS-00-005	Electrical Schematic Blackstart Schematic	EirGrid Design Standard Drawing
PG406-D010-682-001	RTU Substation Control Cabinet Schematic	EirGrid Design Concept Drawing
110KV-STATION_TELECOMS	110kV station SCADA Cabling Overview	ESB Networks Telecoms template drawing
XDS-DGA-00-006	110 kV Substation Control Cabinet	EirGrid Design Standard Drawing

[2] The latest version shall be taken to be the version included in the project specific Contestable Works Pack (CWP) or otherwise agreed with EirGrid. It shall be the responsibility of the Customer to confirm the latest version of any reference document not included in the CWP.

3 General

3.1 Safety

It should be noted that in case of conflict, requirements of ESB Electrical Safety rules shall take precedence over this functional specification.

General operation principle of HV equipment - Lock-Out, Tag-Out Permit to Work System
HV and LV electrical equipment shall be capable of facilitating dead working using a Lock-Out, Tag-Out (LOTO) and permit to work system in accordance with EN 50110-1 in the following specified sequence (also known as the "5 golden rules" for electrical safety):

1. Disconnect completely
2. Secure against re-connection (i.e. lock-off disconnector mechanism and electrical control of disconnector)
3. Verify absence of operating voltage
4. Carry out earthing and short-circuiting
5. Provide protection against adjacent live parts

All HV and LV switchgear and associated control systems shall be designed to facilitate ESBN LOTO requirements for operation and maintenance tasks.

Particular attention shall be given where three position switches using common control supplies are used to perform disconnection and maintenance earthing functions. Further details of the associated switchgear isolation and lock out facilities are outlined in EirGrid GIS Functional specification XDS-GFS-25-001.

Yellow background shall only be used for safety warning purposes. In all new Transmission substations, unless otherwise agreed, all other labelling including identification tags for cables across the station shall be white background black font.

3.1.1 Customer Interface

The first point of disconnection on the Transmission side of a Customer interface shall normally be at EirGrid's transformer disconnect (HV DT).

In order to ensure that work can safely be carried out at the interface or on the point of disconnection itself, it must also be possible to establish a point of disconnection on the Customer side.

All switchgear configurations must facilitate operation in accordance with ESBN Telemess procedures and incorporate interlocking in accordance with established principles.

In all cases the point(s) of isolation & earthing shall be capable of being secured in the on and off position using an ESB standard padlock (7mm minimum diameter hole).

The locking mechanism for the point of isolation shall be independent from the locking mechanism for the earth switch.

It must be possible to readily confirm the status of the Customer's plant by visual inspection[3].

As the point of isolation will typically be at the lower voltage side of the customer's grid-connected transformer it shall generally be achieved by ensuring that the customer switchgear complies with one of the following designs:

- A withdrawable circuit breaker whose racking mechanism (point of disconnection is the racking mechanism) can be locked open when racked out. It must be possible to lock the busbar shutters closed if the busbar shutters are selected as the point of disconnection as opposed to the racking mechanism.
- A fixed circuit breaker and separate disconnector and earthing switches that can be locked in the open and closed positions.
- A fixed circuit breaker and a separate three position disconnector and earthing switch (with On, Off and Earth positions) that can be locked in the off position[4].

Further requirements relating to Customer equipment may be agreed with the Customer as part of the connection offer or during the connection interface design process.

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[3] If the switchgear does not contain a visible break in the circuit, for example it is not withdrawable, the following additional requirements shall apply. Tests on the kinematic chain associated with the disconnector and earthing switch, shall be carried out in accordance with Annex A of IEC 62272-102. These tests shall be carried out by a recognised test laboratory. Copies of certification must be made available on request.

[4] Additional requirements may apply where such switches are being used for both isolation and earthing as part of Telemess i.e. capable of being padlocked in the off position prior to application and subsequent padlocking of the earth.

4 GENERAL CONTROL REQUIREMENTS

4.1 CONTROL ROOM

The standard arrangement of substation shall contain a centralised control building (or room within a GIS building) to locate the secondary systems (Control and Protection) and auxiliary power supply equipment required to ensure reliable local operation of the high-voltage substation equipment.

The secondary equipment in the control room provides functions such as controlling, signalling, monitoring, measuring, recording and protection.
Alternative substation configurations using dispersed relay rooms can be considered by the Customer subject to EirGrid review.

The control building shall also contain operator related service areas containing equipment for the ongoing operation and maintenance of the high-voltage substation equipment. The control building will normally be unmanned, but will be visited by operations staff on a rota basis for maintenance, operations and when fault conditions/alarms arise. Supervision and remote control of the substation will normally be exercised from the National Control Centre (**NCC**) and/or National Distribution Control Centre (NDCC).

The control room design shall take account ergonomic aspects such as a methodical and clear arrangement of panels to facilitate ease of access for operation, maintenance and future developments. Further details are outlined in EirGrid Control room drawing XDN-CR-STND-H-001, Substation Civil and Building Works specification XDS-GFS-13-001 and the project specific requirements.

The substation control point is the central control point location within the substation where the operator performs switching operations. The substation control point shall be located such that it is immediately within view of an operator when he/she enters the control room.

An operator’s desk and chair and a filing cabinet shall be provided in the control room.
A meeting table and 6 stackable chairs shall be provided in the mess room.
In **RTU** substations, the station event recorder and/or alarm annunciator panel shall be located adjacent to the control point to facilitate ease of operation.

4.1.1 FUTURE PROOFING

Substation secondary systems may be extended or modified for a number of reasons during a substations life cycle, be it additional future bays required, substation configuration altered, primary plant upgrades and/or additional secondary equipment installed.
Newly constructed control buildings shall be suitably sized to house protection and control equipment for the ultimate development of the substation and these future cabinets shall be shown in layout designs for initial substation developments.
LVAC, Battery systems and associated distribution boards shall be installed to cater for the ultimate development of the station whereas space only is acceptable for future bay protection relay cabinets.

Substation wide protection schemes shall be designed to allow the future extension to take place with the minimum requirement for substation wide outages.

The following systems shall be given particular attention

- Busbar protection
- Circuit Breaker Fail
- Synchronising
- Interlocking

Space for future cabinets shall have access from at least 3 sides (i.e. will not require new cabinet to be installed between 2 existing cabinets).
The Customer shall consult EirGrid for exact requirements if necessary.
Refer to the latest revision of the EirGrid standard control room layout drawing (for AIS and GIS substations) XDN-CR-STND-H-001 for representative layouts of a transmission substation control room for guidance on **RTU** station applications.

4.1.1.1 MULTIPLE BAY CABINETS

The following requirements shall apply to all substation wide cabinets and those involving equipment associated with multiple bays (including Substation Control Cabinet, AAP, Busbar protection, ETIE, Telemetering etc.).

All new substation wide control points shall be suitably designed and sized for the expected ultimate development of the substation as defined in the project specific SLD.
For **RTU** controlled substations, any additional cabinets required to accommodate the future bays shall be installed during the initial build. Space provision only for future cabinets is not acceptable.

The design layout shall be installed to allow easy and accessible future expansion of the substation while the initial plant remains in service and controllable from the substation and remote control points (NCC).
Trunking and all other items shall be arranged to facilitate future expansion or additions to the cabinet with minimum disturbance.
Initial design shall allow for future terminals for new wiring associated with additional bays.

4.2 SUBSTATION CONTROL

Control and monitoring of the substation high voltage equipment shall be achieved from separate locations as outlined below. (However, existing brownfield substations may not have all the control points referred to below.)

4.2.1 OPERATOR CONTROL

1. Plant Control Point (PCP)

The PCP refers to the operating point directly at an individual item of HV plant. This may include electrical controls in the plant mechanism box or manual operating handles / levers.

2. Bay Control Point (BCP)

The BCP refers to the control point specific to a particular bay. This shall be in close proximity[5] or mounted on the HV plant and will generally be the Local Control Cubicle (LCC[6]).
Generally, the BCP are used during maintenance, commissioning or as backup for use in the event of failure of a remote control point.
Some bay control functions shall also be provided at the associated bay protection cabinet (e.g. Special Protection Scheme, auto reclose selection).

3. Substation Control Point (SCP)

The SCP in a substation refers to the central control point where an operator can control all of the high voltage equipment[7].
There are two distinct types of SCP depending on the control system technology, namely Substation Control System (SCS) or Remote Terminal Unit (RTU) type control systems.
In **SCS** substations, the SCP shall be the Central HMI[8] (and synchronising panel adjacent if required).

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[5] For SCS controlled AIS plant the BCU shall be housed in a dispersed relay room (this is a room located close to the bay equipment containing all bay specific control and protection equipment and is alternative to the standard practice of these being located in a certral relay room). For retrofit in legacy substations an enclosure with suitable environmental controls shall also be acceptable. For HIS in close proximity to a control building the BCU may be located in the control building by agreement on a case by case basis.

[6] LCC is the preferred term for these control points. Historically these were often referred to as bay Marshalling Kiosks (MK) in AIS substations. For new transmission substations MK should only be used to refer to kiosks without any associated control facility.

[7] On Load Tapchanger (OLTC) control has traditionally been considered as part of central Substation control, therefore OLTC cabinets shall be located as close as possible to the SCP.

[8] In certain cases (e.g. multiple GIS buildings) multiple Central HMI may be required. The Customer shall confirm detailed requirements with EirGrid & ESB on a project by project basis

In **RTU** substations, the SCP shall include the Substation Control Cabinet (also commonly referred to as a Mimic or Mosaic Panel) and adjacent Event Recorder[9] cabinet (and synchronising cabinet if required).

4. Remote Control Point (RCP)

The RCP point refers to the EirGrid National Control Centre (NCC), ESBN National Distribution Control Centre (NDCC) and all associated emergency or backup (ECC) control centres.

4.2.2 Non Operator Control

A number of automatic operations shall also be incorporated into the control and protection system including:

- Circuit Breaker tripping
- Circuit Breaker auto-reclose
- Auto changeover

The automatic control point requirements shall be determined by the project specific requirements.
This location of these control points can vary depending on whether an SCS or RTU control system is to be implemented, whether centralised or dispersed relay rooms are to be used and whether GIS or AIS switchgear is to be used.
Full details shall be outlined in the project specific Protection Specification and associated elementary drawings.
It should be noted that additional DSO requirements may also apply. These requirements are outlined in separate specifications & standards.
Full details of individual equipment dedicated control (power electronics, equipment cooler control, battery charging, generator control etc.) is not outlined in this specification. Requirements can be found in the relevant equipment functional specification.

4.2.3 Control Point selection

A series of control selection switches shall control the manual mode of operation of the control system. These switches shall determine which control point has active control of the HV equipment.
Examples are “Master Remote Control On/Off” switch in NCC RTU or SLC cabinet, “Bay sub remote control switches” at substation control point and “Remote/Local control switches” at SCS Bay Control Units.

Selection between automatic and manual modes of operation for various systems shall be outlined in the project specific Protection Specification (Tripping, Auto-reclose, Synchronising, Tap changer) or the relevant equipment functional specification (Cooler control, Standby generator, Battery charger etc.).

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[9] Event recorders shall be installed in all new Transmission substations. Extension or modification of existing legacy Alarm Annunciator Panels (AAP) shall be confirmed with EirGrid on a case by case basis

5 CONTROL POINT REQUIREMENTS

This section outlines the functional requirements and typical layouts at the various control & monitoring panels/cabinets. For details of panel construction requirements (including wiring, terminals etc.) please refer to functional specification XDS-GFS-07-001.

5.1 REMOTE CONTROL POINT

In all transmission substations, there will be both a NCC interface (e.g. RTU) for remote HV Plant control and monitoring with dedicated communications to the National and Emergency Control Centres and a separate NDCC RTU with dedicated communications to the Distribution Control Centre. These are independent systems and signals shall be provided separately to each.

The remote control point shall be provided with control and indication for certain high voltage equipment in the substation, please refer to the project specific signal lists for all NCC & NDCC control and monitoring requirements.
Section 6 and section 8 of this specification also provide further information.

Remote control facilities to NCC shall be outlined in the project specific signal list which will include the following functions:

- All motorised circuit breakers and disconnectors open and close commands (control of earthing switches shall not be provided to NCC).
    - For **RTU** substations this shall be implemented by the provision of DC 24/48 V interposing relays in the interposing cabinets. SCADA remote control shall be double pole switched. The Sub-remote control switch (when off) shall remove the circuit breaker and disconnectors control supply from the contacts of the interposing relays.
    - For **SCS** substations this shall be implemented through contacts on the respective BCU which operate directly on the individual plant DC 220 V control circuits.
- ON and OFF control for the Blue Alert system. See drawing XDS-DELS-00-004. Silence alarm and signal system reset commands.
- ON and OFF control of the Auto-Reclosers and SPS on bays.

Non-revenue[10] CT and VT metering circuits shall also be connected back to remote control point. For NCC this shall consist of 3 phase <u>directly connected</u> CT and VT circuits i.e. not using interposing CTs or transducers.

For **RTU** substations the circuits should be connected to the telecoms telemetering cabinet for telemetering via the NCC RTU. The Voltage, Current and Power (MW and Mvar) metering to NCC/ECC will be provided by ESB Networks Telecoms.

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[10] A distinction is made between revenue metering (main and check) used for customer billing and other metering used for instrumentation and monitoring.

For **SCS** substations the instrument transformers shall be connected to the respective Bay Control Units.
If required (refer to NDCC signalling requirements), NDCC metering shall be separately provided by presenting the mA outputs from dedicated transducers in the Substation Control Cabinet to the NDCC RTU located in the control room.
The interface points to the substation shall be the EirGrid NCC RTU and ESBN NDCC RTU cabinets.

5.1.1 Master Remote Control On/Off

A switch shall be provided to disable all control commands from the remote control points (NCC, ECC, NDCC). Remote switchgear position indication, alarms or measurands shall not be controlled by this switch. Such indications shall be available at remote control points regardless of whether the switch is "ON" or "OFF".
The status indication of this switch shall be brought back to NCC.

For **RTU** controlled substations, this switch shall be located in the NCC RTU supplied and installed by ESB Networks Telecoms on behalf of EirGrid.
This switch breaks the positive and negative leg of the command supply. No voltage is present at the command terminals when this switch is in the "OFF" position.
A separate master remote control switch shall be provided on each RTU e.g. TSO (NCC) and DSO (NDCC) RTU.

Figure 2: Master Remote Control On/Off installed on RTU

In **SCS** controlled substations, it is implemented via a physical selector switch[11] on the substation SLC cabinet. This is wired to a binary input on the SLC to provide the functionality of blocking commands from remote control point via software. The central HMI also captures the status of the physical switch

[11] This switch is also sometimes referred to as Station Local/Remote or Master Scada on/off switch in legacy SCS substations.

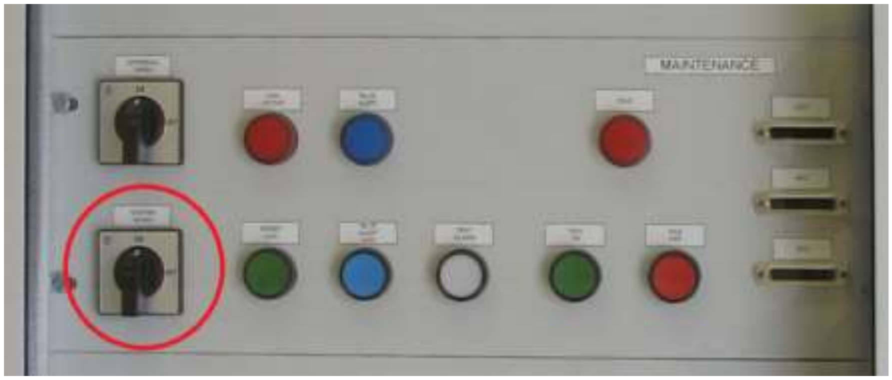

Figure 3: Master Remote Control On/Off installed on SLC

5.2 SUBSTATION CONTROL POINT

5.2.1 SUBSTATION CONTROL CABINET

This section describes the functional requirements in **RTU** substations.
Equivalent functionality shall be incorporated into the Station Level controller for **SCS** substations. Please refer to section 5.2.2 and functional specification XDS-GFS-24-001 for further details.

A Substation Control Cabinet containing a single line diagram (mimic) of the switchgear arrangement shall be provided to represent the physical disposition of the substation.

Control commands (Open / Close) are to be made available at the substation control point for all high voltage equipment except non fault make rated earthing switches (typically maintenance earthing). These shall only be operated from the Bay or Plant control point.
Customer transformer earthing switches (typically identified as DEM4 on SLDs) are required to be fault make rated and operable from the Substation Control Point.

All control shall be double pole switched (with the exception of circuit breaker open command, which is not switched on the negative).
Position indications are to be made available at the substation control point for all high voltage equipment (including busbar and maintenance earths where installed).
Position indication of customer HV equipment shall also be made available at the substation control point.
Detailed requirements shall be outlined on a project specific basis depending on the customer switchgear arrangements.
Semaphore LED indicators shall be used for position indication of plant not controllable from the Substation Control Cabinet.
VT symbols shall be used clearly showing the point of measurement. Where multiple VTs are installed it shall be clearly shown which set is connected to any instrumentation on the cabinet.
CT symbols are not to be shown on the Substation Control Cabinets.

The single line diagram shall adhere to the colour codes[12] listed in Table 22 for the various voltage levels to be represented.

Table 2: Busbar colour codes

Voltage	Colour	RAL Number	Sample
400 kV	Black	RAL 9004	
260 or 275 kV	Green[13]	RAL 6001	
220 kV	White	RAL 9003	
110 kV	Red	RAL 3020	
38 kV	Yellow	RAL 1018	
20 kV	Orange	RAL 2003	
13.8 kV	Violet	RAL 4001	
10 kV	Blue	RAL 5010	
6.6 kV	Brown	RAL 8001	
3.3 kV	Green	RAL 6001	
380/400 V	Black	RAL 9004	
Other voltages	Medium Grey	RAL 7046	

Due to differing quality of printers the colours indicated in Table 22 may appear slightly different to the actual colour on the mimic. Direct comparison should only be made using certified RAL colour cards.

Where mimics are shown on LCC or on MV switchgear (where operational voltage may be 10 or 20 kV) the SLD shall be black RAL 9004.

Colour for the earth symbol should be Green – RAL 6001.

The preferred colour for the background is RAL 7047, however alternatives may be considered if they provide adequate contrast to the other colours indicated in Table 1. In such cases an alternative grey may also be considered for "other voltages to provide adequate contrast.

Text face should be Black – RAL 9004.

All new Substation Control Cabinets shall be arranged with horizontal busbars (see Figure 44), with the higher voltage busbar on top and the lower voltage busbar on the bottom.

For double busbar substations, the substation control cabinets busbars shall be arranged with A above B.

Line bays and Transformer bays should be arranged for clarity, in general starting with the highest voltage busbar, line bays should be shown coming in from above and transformer (or other substation plant) bays leaving from the bottom. Note: this is then inverted as appropriate on any lower voltage busbars.

[12] These colour codes relate to all new substations. Where an existing substation mimic uses an alternative convention, guidance shall be sought from EirGrid whether to maintain the existing convention or upgrade the entire mimic. Under no circumstance shall conflicting colour codes be used on a single mimic.

[13] Note: Black was originally used to represent 275 kV at Louth substation. However, this has been changed to address the scenario of 400 kV at this substation.

Vertical Busbar Substation Control Cabinets (see Figure 55) are only acceptable in existing substations where new bays are being installed. This should only be done where it is appropriate to extend the existing mimic.

Note; Figure 44 and Figure 55 are for indication only and do not represent detailed design.

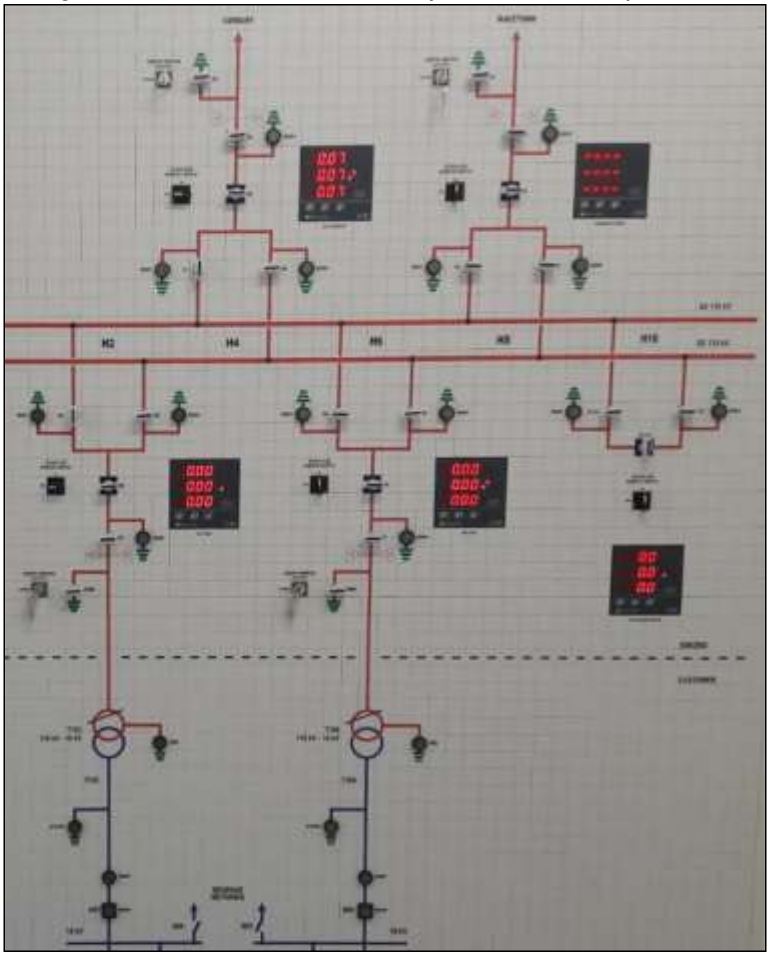

Figure 4: Substation Control Cabinet with Horizontal Busbars

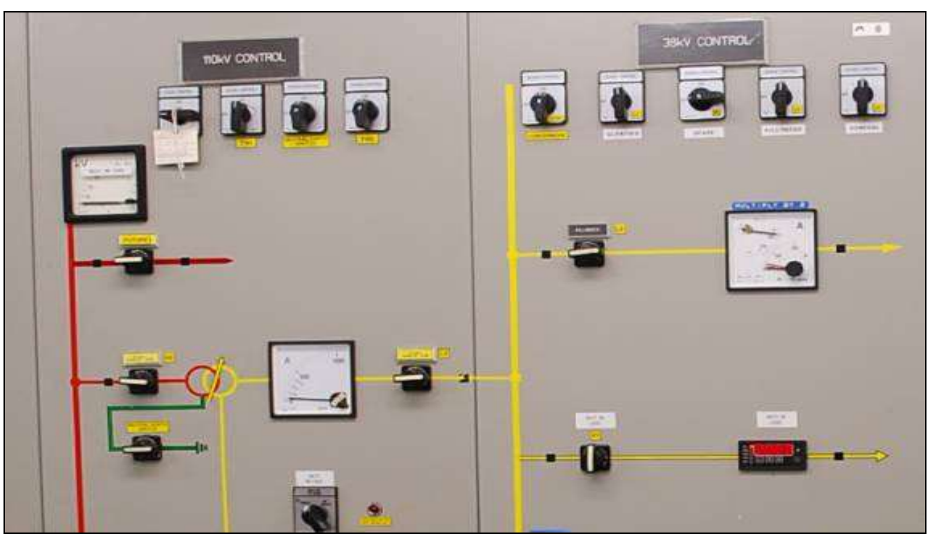

Figure 5: Substation Control Cabinet with Vertical Busbars

5.2.1.1 SUBSTATION CONTROL CABINET EQUIPMENT

The substation mimic shall be clear and indelibly applied. This may be achieved by the use of painted or printed panels or using a tiled mosaic system. The use of adhesive strips or tapes shall not be accepted.

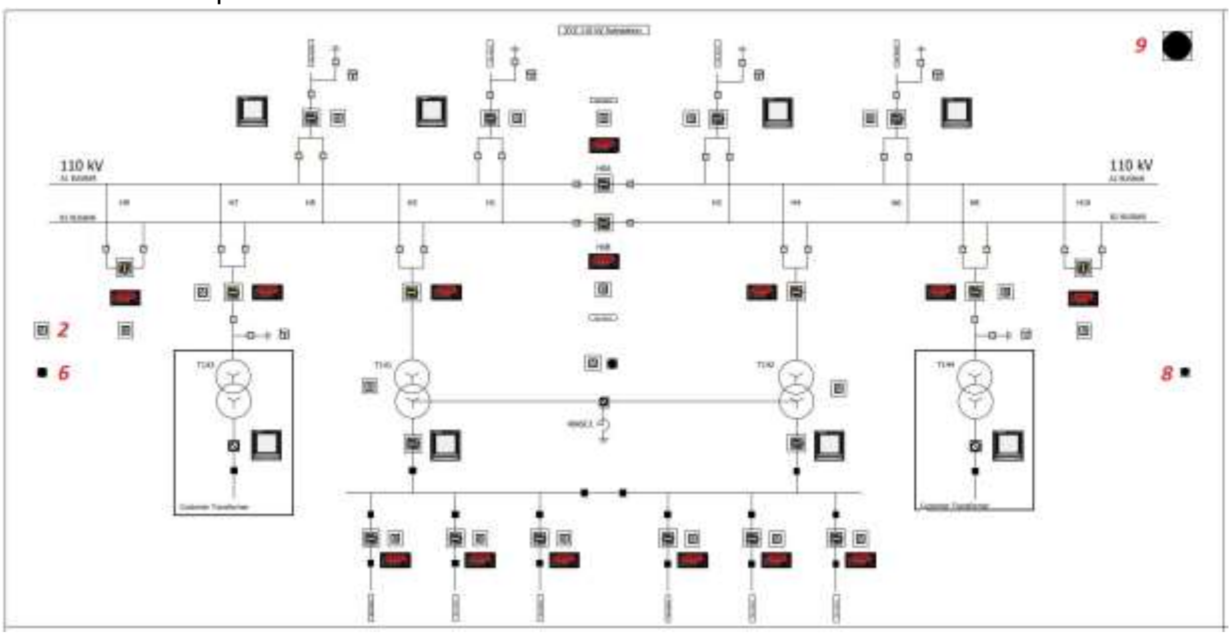

Figure 6: Substation Control Cabinet - Switches and Lamps

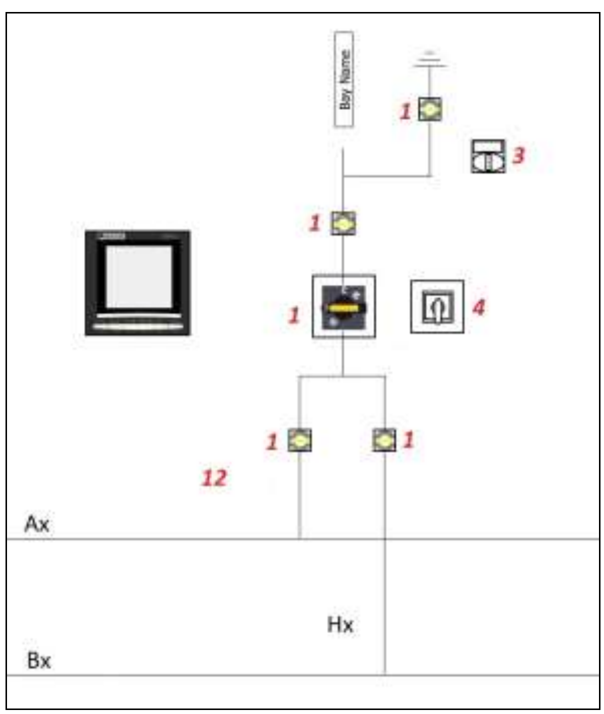

Figure 7 - Typical bay on Substation Control Cabinet

The substation control cabinet shall have, as a minimum, the switches and indications as outlined in Table 33 and the project specific documentation. Switches and Lamps listed in the table below are shown in the above Figures. More detailed guidance is available in PG406-D010-682-001.

Table 3: Substation Control Cabinet Switches and lamps

Label	Switch /Lamp
1	Illuminated command (control and discrepancy) switches.
2	Substation Control Cabinet On/Off switch. (Legacy substations only)
3	Earth Unlock Key switch.
4	Bay Sub Remote Control On/Off Switch.
5[14]	Emergency Telephone Push Button.
6	Mimic lamp ON and lamp test push button. (Note: Lamp on/off in some legacy substations)
7[14]	A lamp test push button. (Legacy substations only, now incorporated into 6)
8	Blue Alert lamp and acknowledge switch. (Must be Blue colour lens).
9	Blue Alert sounder.
10[14]	Blackstart On light (where specified)
11[14]	Blackstart Reset pushbutton (where specified)
12	Bay measurand Indication meters
13[14]	Voltage selection switches. (if required)
14[14]	Check Synchronising illuminated push buttons (where specified)
15[14]	Check Synchronising instruments (where specified)
16[14]	Check synchronising Status lamps (where specified)

5.2.1.2 Illuminated command (Control and Discrepancy) Switches

Illuminated control and discrepancy type switches shall be installed on the Substation Control Cabinet for all High voltage switchgear except those noted in section 5.2.1.

The circuit breaker switches shall have square escutcheons; all others shall have a circular escutcheon and shall be used for the operation and position indication of the switchgear.

These switches shall only be illuminated while “lamps on” is running, section 5.2.1.7 refers.

[14] Not fully illustrated.

If a switch position agrees/matches the position indication of the high voltage switchgear it controls, then its discrepancy lamp shall be illuminated with a steady light.
If there is a disagreement between the position of this control switch and that of the item of switchgear the lamp shall be illuminated with a flashing light (flicker of 1 Hz with 1:1 on/off cycle).
The switch shall require two independent movements to effect operation and the procedure shall be as follows.
Consider that the item of switchgear is open with its control and discrepancy switch in agreement and steadily illuminated. In order to perform a close operation, the control and discrepancy switch shall first be turned 90° to the closed position.
It shall then be illuminated by a flashing light as its position is in disagreement with that item of switchgear. The switch shall be depressed and turned in the same direction. This item of switchgear shall close and the flashing light on the switch shall be replaced by a steady light confirming its new closed position. To open the item of switchgear, the reverse operation is needed.
The conventional orientation of clockwise to close shall be applied.

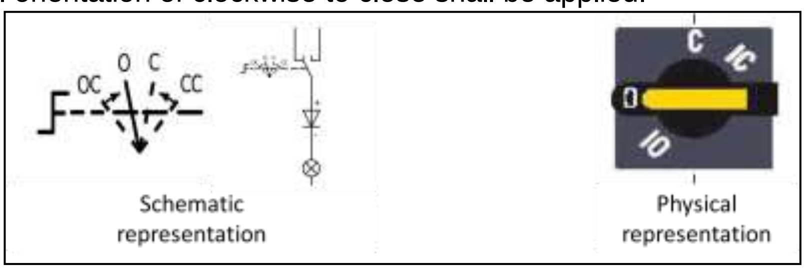

Figure 8 – Typical Control and Discrepancy switch

The circuit breaker control switch shall be connected to the CB close coil and open coil No.1.
The control and discrepancy switches in the substation control cubicle shall operate using the station DC 24/48 V supply[15] and be connected to the equipment control circuits through interposing relays.
LED semaphores (where red is used for closed and green for open) shall be used for items of plant not controllable from the substation control cabinet. The use of mechanical flag semaphores is not generally permitted.

An exception is for Arc Supression Coil (ASC) changeover switches on DSO transformers where a mechanical flag indicator may be used. Such flags shall have a neutral position which clearly shows loss of supply or semaphore failure.
Semaphores shall only illuminate when the associated plant is in the fully open or fully closed state and shall show loss of DC supply, intermediate position or conflicting position indication as per Table 44.

[15] This applies to all new transmission substations, In some legacy substations the command switches act directly in the plant DC 220 V control circuit. A decision whether to expand based on the existing convention or replace shall be agreed with EirGrid on a project by project basis depending on the extent of modification works.

Table 4 Discrepancy indication

Condition	Discrepancy	LED type
Loss of DC supply (or "lamps on" timer elapsed)	Not illuminated	Both elements off
Plant not in end position (not open & not closed)	Not illuminated	Both elements off
Plant status conflict (open and closed)	Illuminated solid (not indicated)	Both elements on
Plant status and flag status not aligned	Illuminated flashing	N/A

5.2.1.3 Substation Control Cabinet On/Off Switch

There is no requirement for a dedicated substation control cabinet On/Off switch in new substations. All DC circuits in the substation control cabinet shall be derived from the Station DC supply (24 or 48 V depending on substation primary voltage). DC 220 V control circuits shall not be routed through the substation control cabinet.

In legacy substations the substation control cabinet (or Mimic) may have such a switch[16] installed. In general, the purpose of this switch was to isolate the DC 220 V control circuits and disable control from the Substation Control Point. Modification or extension works in legacy substations should maintain consistency with the existing design (i.e. new bays control and indication shall also be conditioned by the switch) unless specifically outlined otherwise in the project specific CPP/CWP. Care shall be taken in such instances as there are a number of slightly different legacy designs.

Under no circumstances shall any such switch disable any of the following:

- Blue alert warning and acknowledgement.
- Operation from the **plant, bay or remote control points** (including Sync closing from NCC).
- Alarms or indications to the Event recorder or Alarm annunciator Panel (AAP).
- Operation from Protection devices.

There is no equivalent switch for **SCS** controlled substations.

5.2.1.4 Earth Unlock Key Switch

For **RTU** controlled substations, a dedicated earth unlock key switch shall be installed on the Substation Control Cabinet and Bay Control Points for feeder and TSO Customer Transformer earthing switches.

The substation project specific interlocking requirements specification shall be referred to for the application of these key switches for their respective bays.

This key switch shall be located adjacent to the control & discrepancy switch for the respective earthing switch.

[16] Substation Control Cabinet ON/OFF switch is also sometimes referred to as Master On/Off switch but should not be confused with the master remote control on/off on the RTU as outlined in 5.1.1 above.

This key switch must be in the unlocked position before a successful operation can be performed from the Substation Control Cabinet. This key switch is designed as an additional step for operators (to stop and think) before operating an earthing switch.

For **SCS** controlled substations, no dedicated earth unlock key switch is required if the system's own command logic provides adequate protection. (i.e. if the system requires the operator to go through a two or three step decision process to operate the earthing switch this is deemed to provide an equivalent level of protection).

5.2.1.5 Bay Sub Remote Control On/Off Switch[17]

A selector switch shall be provided to disable all control commands from the remote control point for each bay.
For **RTU** controlled substations, bay sub remote control switches shall be installed on the Substation Control Cabinet adjacent to each bay[18]. Each switch shall be located to avoid any ambiguity as to which bay control is controlled by the switch.

The switch shall operate such that when in normal operation **On** position (Remote):

- Operation control commands from both the remote and substation control points will be passed to the respective bay control point.

The switch shall operate such that when in **Off** position:

- Operational control of bay equipment from the remote control point is disabled. Control of other bays shall not be affected.
- All signals (Position indication, Alarms and measurands) to the remote control point are maintained.
- Operation from protective devices is not affected.
- Operation from the substation control, bay and plant control points is not affected.

Each switch should break both positive and negative legs of the command to all plant within the bay (excluding Circuit breaker opening[19]).
Bay level remote control On/Off switches shall also be installed on protection cabinets in accordance with the relevant protection elementaries (e.g. Tapchanger control, Feeder Auto Reclosing and any Special Protection Scheme).
Three separate bay sub remote control key switches are required on utility transformers (EirGrid/ ESB i.e. transmission 220/110 kV and distribution coupling transformers 110/38 kV) to enable & disable remote control of each side of a transformer bay. (One for each of the respective voltages and the third sub remote control switch shall be provided on the protection

[17] Note: Bay Sub Remote Control switch is also historically known as the SCADA ON/OFF switch. NCC defines the title of the switch as Sub Remote Control Switch.

[18] Note, for RTU, three separate Bay Sub remote control switches are required for coupling transformer bays (HV bay, LV bay and OLTC control)

[19] Only the positive leg is used for Circuit breaker opening. It is important to emphasise that the switch should not interrupt any tripping circuits.

panels in accordance with the protection elementaries (to enable & disable remote control OLTC control).

Figure 9: Bay Sub Remote Control On/Off switch (RTU substation)

For substations with **SCS** installations, there is no direct equivalent to the bay sub remote control at the Substation Control point. The closest functional equivalent is the remote/local control key switch incorporated into the Bay Control Unit (BCU)[20.]

5.2.1.6 Emergency Telephone Push Button

A push button shall be installed to allow operations personnel at the substation to alert NCC if the telephone connection is engaged or not functional.
The push button shall be non-latching and provided with a normally open pulse contact.

For **RTU** controlled substations, the push button shall be located in a prominent position on the Substation Control Cabinet.
For **SCS** controlled substations the pushbutton shall be installed on the SLC cabinet
This push button shall be coloured **red** with engraving “Emergency Telephone” and provided with a transparent flap cover. The push button indication cabling shall be wired to the NCC RTU enclosure location in the control room.

5.2.1.7 Mimic Lamp On Switch

A mimic lamp on push-button switch shall be provided to enable all illuminated semaphores and lamps on the Substation Control Cabinet. This shall be a black coloured, non-latched, push button type switch. This shall operate a timer relay (delay drop off) with a settable range of 1-10 Hours (default setting 1 hour). This shall also enable the supplies (steady and flicker) to the control and discrepancy switches in the Local Control Cabinets.

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[20] This uses the BCU software to enable & disable commands from BCU and upstream. A notable difference compared to RTU substations is that local (BCU HMI) operation is blocked when the switch is in Remote position.

A supply shall not be available for indication purposes on the board when the timer relay has elapsed. Note the below:

- The mimic lamp circuit shall not disable the control function of the control and discrepancy switches.
- Auxiliary supplies to digital meters shall not be interrupted by the timer relay.
- The "Blue Alert" function shall not be disabled regardless of the status of the "Mimic Lamp On" timer relay.

This push button shall also perform the lamp test functionality while the button is depressed.
The lamp test functionality shall allow verification that all lamps and semaphores on the Substation Control Cabinet (including Blue alert) are working. The lamp test facility may rely on dual indication to verify lamp integrity (i.e. normal indication of control and discrepancy switches where the lamp will be either on or flashing is considered acceptable). All indications shall revert to their true state when the push button switch is released.
The use of blocking diodes to prevent back energisation of indication through the lamp test facility shall not be accepted[21].
It should be noted that in legacy substations there may be alternative arrangements. Most commonly:

- Flicker supply is not always interrupted by the "lamp on" circuit.
- Functionality may be by 2 position On/Off switch rather than timed circuit.
- Lamp test facility is not always present.
- Lamp test may be via dedicated test push button.

Guidance shall be sought for works in such substations as to whether any new equipment should maintain the existing philosophy or whether the substation should be brought in line with this specification.This functionality is only required in **RTU** substations.

5.2.1.8 Lamp Test Switch

A dedicated push button lamp test switch is not required in new substations, see section 5.2.1.7.

5.2.1.9 Blue Alert

The blue alert system is an arrangement by which EirGrid advises its operators in various locations in the network that its system is in a critical condition and receives confirmation that the operator is ready to take action as required by EirGrid.
This shall be in accordance with EirGrid design standard XDS-DELS-00-004.
The Blue Alert push button shall be positioned in a prominent position on the Substation Control Cabinet. This shall consist of an Illuminated push button with a blue lens.
A dedicated DC supply shall be used for the Blue Alert system. This shall be taken from the isolated telecoms supply (which shall be DC 24 V or 48 V depending on the substation primary voltage level). Refer to EirGrid functional specification XDS-GFS-09-001 for further information.
The Blue alert function shall not be disabled by the Substation Control Cabinet On/Off switch, nor shall it be disabled by the mimic lamp switch (see sections 5.2.1.3 and 5.2.1.7)

[21] Modification/extension or replacement of such arrangements in existing substations shall be advised by EirGrid on a case by case basis.

In the case of **SCS** controlled stations, the Blue Alert system shall be routed through the Station Level Controller (SLC) supported by the IEC 101 control centre links.

5.2.1.10 BLACKSTART

Requirements for blackstart shall be specified by EirGrid on a substation by substation basis in the project specific protection specification.
Further details are outlined in EirGrid functional specification XDS-GFS-21-001.
Where required, a “Blackstart on” lamp and reset pushbutton shall be provided on the Substation Control Cabinet. Please refer to EirGrid schematic XDS-DELS-00-005.

For **SCS** substations, this functionality shall be incorporated into the relevant BCU(s).
In addition to tripping the respective TSO bay circuit breaker and initiating a flashing warning on the HMI, activation of the scheme shall trip the IPP MV CB via a single binary output on the BCU. Two additional outputs on the BCU shall also be configured to provide the double bit (Black start On/Off) status indication to the IPP. The scheme shall be capable of being activated and reset from the NCC and reset from the substation central HMI (soft switch). This shall only be possible when the BCU local remote switch is in the Remote position.

5.2.1.11 BAY MEASURAND INDICATION

Indicating meters shall be provided to measure the following for each bay.
Current (in A). "S" phase current if single phase analogue ammeter is used.
Voltage (in kV). Display of all phase and line voltages (R-N, S-N, T-N, R-S, S-T, T-R) in kV shall be possible using a single meter and a voltage selection switch.
An integral selection facility within a 3 phase digital meter is also acceptable.
If more than one VT is installed on a HV circuit then it must be clear which VT reading is being displayed by the panel meter(s).
Active power (in MW).
Reactive Power (in Mvar).
A multifunction meter capable of displaying all of the above shall be used.
All Indicating meters on the Substation Control Cabinet shall be suitably scaled for the particular bays.
The meters shall differentiate between export (“+”) and import (“-“) of power (MW and Mvar) where export is power flow away from the busbar. They shall also be suitable for connection to a three-wire, three-phase, unbalanced system.
The meters shall be flush mounted and have an accuracy class of at least 1.5[22].
The meters shall be connected to the non-revenue metering CT and VT circuits, via a serial output on transducers. These shall be minimum accuracy class 0.5 and shall also have mA DC output of 0 to 10 mA (I & V) or -10 to + 10 mA (MW & Mvar). Where required, these mA outputs shall be used to provide DSO remote metering via the NDCC RTU. The transducers shall derive their auxiliary supply from the station DC supply (24 or 48 V depending on substation voltage level).

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[22] Note, this applies to the multifunction meter only, the instrument transformers and transducers may have a higher accuracy class.

The meters shall generally be located on the Substation Control Cabinet, where they must be aligned with the relevant bay. Alternatively, subject to agreement with EirGrid, they may be installed in a separate metering cabinet which must be located adjacent to the Substation Control Cabinet. Standard substation metering instrumentation shall not be combined within any Synchronising cabinet.
Dedicated metering per bay is required i.e. a common instrumentation scheme with selection of information from each bay to common sets of meters is not acceptable.
As outlined in section 5.1, the transducers used for local and DSO remote metering requirement are separate to those in the telemetering cabinet used for NCC remote metering.
Measurands shall be incorporated into the SLC and available at the central HMI in **SCS** controlled substations.

5.2.1.12 Synchronised Closing

Where required, synchronising control facilities shall be provided. This shall be outlined in the project specific protection specification.

For **RTU** substations the control point shall be provided at the Substation Control Cabinet. Alternatively, subject to agreement with EirGrid, they may be installed in a separate dedicated synchronising cabinet which must be located adjacent to the Substation Control Cabinet. Further details are outlined in section 6.2.

For **SCS** substations this functionality (excluding the controlled Sync close facility) shall be incorporated into the SLC and available at the central HMI.
The controlled sync close facility shall be installed on the Substation Control Cabinet or dedicated synchronising cabinet which must be located beside the Substation Control Cabinet (**RTU** substations) or Central HMI (**SCS** substations).
Specific synchronising requirements will also be outlined in the project specific Protection Specification.

5.2.2 Station Level Controller Cabinet

For **SCS** controlled substations, much of the substation control functionality shall be incorporated into the Station Level controller and respective Bay Control Units. Substation control shall be available via the central HMI interface. As noted in section 4.2.1, substations may have multiple central HMI.
The additional functionality listed in Table 55 shall also be available via dedicated switches and lamps on the SLC cabinet.

Table 5: Station Level Controller Switches and lamps

Function	Requirement
External Siren	On/Off selector switch (2 position)
Master SCADA	On/Off selector switch (2 position)
General Station Alarm	Lamp/LED (red) & reset switch (non-latched pushbutton)
Blue Alert	Lamp/LED (Blue) & reset switch (non-latched pushbutton)
Remote Access	Lamp/LED (Red) & separate on & off switches (non-latched pushbutton)

5.3 BAY CONTROL POINT

5.3.1 LOCAL CONTROL CABINETS (LCC)

In all transmission substations (both AIS and GIS), the switchgear in each bay shall be locally controlled via its own individual bay local control cabinet[23] (LCC) located in close proximity to the switchgear.
These LCCs must be installed in accordance with the requirements of the latest revision of the EirGrid station control and protection cabinets and marshalling kiosks functional specification XDS-GFS-07-001.

In **RTU** substations the LCC shall be located adjacent to the transmission bay. For AIS substations the LCC shall be incorporated within a suitable weatherproof enclosure. Location and arrangement shall also respect all substation access and DWA requirements as outlined in XDS-GFS-00-001.

In **SCS** controlled AIS (or outdoor GIS) substations, the LCC shall be installed within the relevant Dispersed Relay Room (DRR). Bay Control Units shall not be housed in standard outdoor enclosures or marshalling kiosks. For retrofit or extensions at legacy substations, the use of specific environmentally controlled enclosures shall be acceptable subject to agreement with EirGrid.

For compact HIS or other small installations where the bay is in close proximity to a central control building, the LCC may be installed in a relay room in the control building. Such cases shall be subject to individual detailed assessment and must be formally agreed with EirGrid.

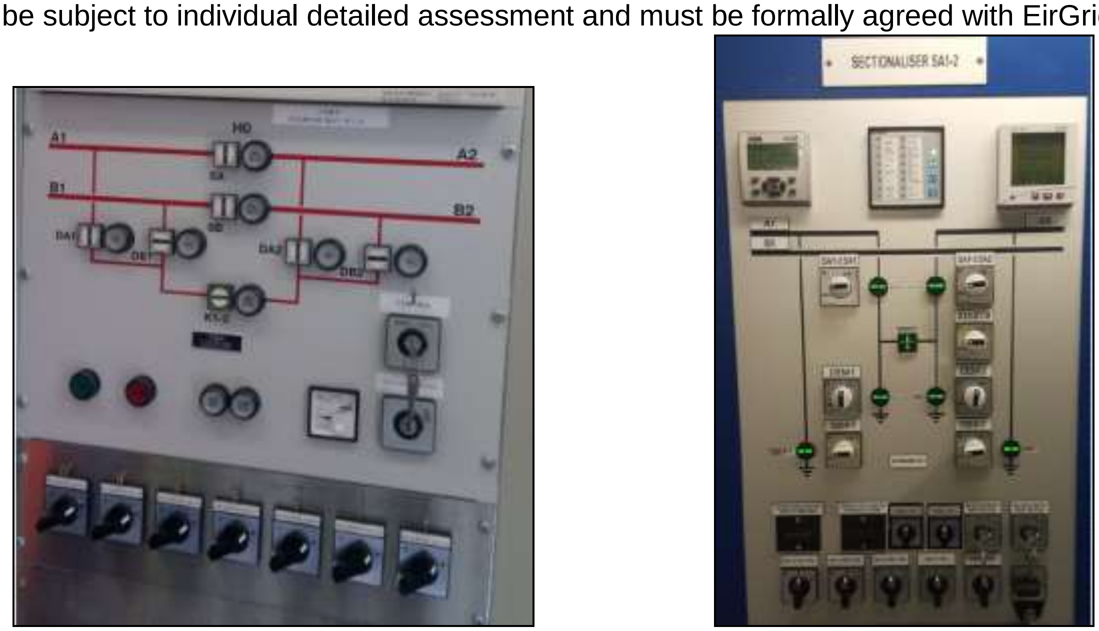

Figure 10: Legacy Bay Control Point (AIS & GIS)

[23] These were previously commonly referred to as bay marshalling kiosks (MK) in AIS substations, however, the term LCC shall be used for both AIS and GIS substations to distinguish the control point from other cabinets or kiosks used for marshalling only.

These control points are required for plant operation during commissioning, testing and maintenance and are required for both AIS and GIS substations and for RTU and SCS applications.

In the case of **RTU** substations a mimic diagram utilising control and discrepancy switches similar to those in the substation control cabinet shall be installed. The legacy types as illustrated in Figure 1010, utilising separate switches and position indication, shall not be installed in new substations.

The voltage level colour codes in Table 22 do not apply to the bay control point mimic which shall be black.

If equipment is to be controlled and operated by a station numeric control system (SCS), the Customer must adhere to the requirements of the EirGrid SCS Functional Specification XDS-GFS-24-001.

In the case of **SCS** substations, a single Bay Control Unit (BCU) shall be mounted in the bay control point and control shall be via the LCD HMI mimic.

A separate indelible single line diagram of the bay shall also be provided. This is to provide an operator with an overview of the bay equipment layout under circumstances where the BCU HMI is unavailable and has no active control or indication elements.

All LCC mimics shall clearly show the location of any associated Voltage Transformers.

In GIS substations, the BCU shall be installed on or adjacent to the switchgear in accordance with EirGrid functional specification XDS-GFS-25-001. In AIS substations the BCU shall generally be installed in a cabinet in the dispersed relay room (DRR). In legacy substations or other where DRR is not installed, the BCU shall be installed in an environmentally controlled enclosure suitable for the device.

Figure 11: Bay Control Point in SCS control

Table 6: Bay Control Switches and lamps	
Label	**Switch /Lamp**
1	Remote Off Key switch (RTU only),
2	Bay Remote/Local Key Switch on BCU (SCS only)
3	Equipment Control and discrepancy switches (RTU Only)
4	Control Isolation Switches (On/Off)
5	Earth Unlock key switch,
6	Interlocking bypass key switch (SCS only)
7	Bay Measurand Indication meters

The mimic shall be designed with clear positioning and labelling of control switches with the standard ESBN plant designations ***only*** as per project specific SLD and signals list. IEC designations shall not be depicted on LCCs.

5.3.1.1 Remote Off Key Switches (Bay)

For **RTU** substations, a dedicated Remote off key-switch shall be provided at the bay control point to disable all upstream remote control of the bay equipment.
This switch is used as a safeguard for personnel working on HV equipment with full knowledge that all upstream (i.e. from substation or remote control points) commands are blocked and the equipment is safe to carry out commissioning, testing or maintenance.

The switch shall operate such that when in Remote off position:

- Operational control can be performed locally (at the bay control point) and remote operation from the substation and remote control points shall be disabled.
- Protection tripping and reclosing are not disabled.
- All indications and alarms to substation and remote control points shall remain available.
- Status Indication of this switch is provided to remote control point that the bay is in local control mode.

The switch shall operate such that when in Remote on position (Normal Operation):

- Operational control is passed to the substation and remote control points.
- Electrical control from the bay control point is not disabled.
- Status indications at the bay and plant control points remain available.

Status indications of the position of this switch shall be provided to NCC (see also section 5.3.1.3).
For **SCS** substations the closest functional equivalent is the remote/local control key switch incorporated into the Bay Control Unit (BCU)[24].

[24] This uses the BCU software to enable & disable commands from BCU and upstream. A notable difference compared to RTU substations is that local (BCU HMI) operation is blocked when the switch is in Remote position.

5.3.1.2 COMMAND SWITCHES

For all new substations, the RTU LCC shall utilise control and discrepancy type switches similar to those in the Substation Control Cabinet. These shall also make use of the flicker discrepancy function. The command function shall operate directly within the plant 220 V control supply circuits (i.e. not interposed from the station 24/48 V supply), but the indication and discrepancy shall be derived from the station indication supply (steady and flicker).

The LCC shall have command switches for operational control of all motorised switchgear (circuit breakers, disconnectors and earthing switches, both maintenance and high speed).
Separate operational switches shall be provided for the disconnector and (maintenance) earthing function of any 3 position switches.
This shall be achieved via the BCU HMI for **SCS** controlled substations.

5.3.1.3 CONTROL ISOLATION SWITCHES

Control isolation switches shall be installed for all[25] motorised switchgear (circuit breakers, disconnectors and earthing switches, both maintenance and high speed) at the LCC.
These shall enable and disable commands from the respective individual command switches or BCU.
Circuit breaker control isolation switches shall only prevent operator control and shall not block any protection device commands (trips or auto-reclose).
These shall be clearly labelled but installed separate from the operational switches.
There shall be a separate Control isolation switch associated with each command switch.
A warning label shall be installed in close proximity to all circuit breaker control isolation switches. This shall be black text on yellow background with the following text:
"Warning. CB Isolation switches block operator commands only. Automatic operation such as protection trips, auto reclose and AFR may still be in service and further isolation may be required."
Note, these switches are required for both SCS and RTU controlled substations.

For **RTU** controlled substations the position indication of all of the control isolation switches in an LCC shall be ganged with the remote off switch to provide single point position indication of the control status of the bay. This shall be provided to the substation and remote control points (i.e. any switch in the off position shall provide a "control off" indication for the bay).

For **SCS** controlled substations the position indication of all of the control isolation switches in an LCC shall be brought back to the respective BCU individually. Only those associated with items of plant controllable from NCC[26] shall be included in the grouped signal to NCC.

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[25] Note that these may not be installed or may only be installed for particular items of plant in some legacy substations. Consistency with existing convention at such substations shall be maintained unless specifically outlined by EirGrid.

[26] The project specific signal list contains details of the plant controllable from NCC. Typically, NCC would not have control of DE or DEM and only has control of DL in legacy substations where some of the DA/DB are or were) interlocked against the DL. NCC would not generally have control of DA in single busbar substations.

5.3.1.4 Earth Unlock Key switch

Similar to section 5.2.1.4, for **RTU** controlled substations, a dedicated earth unlock key switch shall be installed at the LCC for all non-interlocked earthing switches.
This key switch shall be clearly labelled and where possible located adjacent to the operational switch for the respective earthing switch.
This key switch must be in the unlocked position before a successful operation can be performed at the LCC. This key-switch is designed as an additional step for operators (to stop and think) before operating an earthing switch.
Please note, that no dedicated earth unlock key switch is required at the LCC/BCU in the case of **SCS** controlled substation.
For **SCS** applications, the system's own command logic may provide adequate protection. (i.e. if the system requires the operator to go through a two or three step decision process to operate the earthing switch, this is deemed to provide an equivalent level of protection).

5.3.2 Protection Cabinets

Some bay control functions may also be required at the associated Protection cabinet. This may include:

- Transformer voltage/tapchanger control
- Special Protection System (SPS)
- Feeder Auto Reclosing

These requirements shall be outlined in the project specific Protection Specification and associated protection elementaries.

5.4 Plant Control Point

In all new transmission substations, the only electrical control of the primary circuit at the plant control point shall be the circuit breaker opening. All normal electrical operation should be performed from the bay control point or further upstream.

Where electrical operation facilities are provided at the plant control point by the equipment manufacturer as standard, they shall be disabled, removed and have suitable blanking plates fitted to any openings.
Manual mechanical operating requirements shall be as outlined in the relevant equipment functional specification. There is no requirement for a local/remote switch at the plant control point.
A circuit breaker opening push button shall be provided. This shall operate trip coil 1 and this shall not be conditioned by any other control selection or isolation switches (i.e. shall use “standing positive” supply).
It should be noted that in some legacy substations electrical control is available at the plant control point and associated remote/local control switches are installed. Guidance shall be sought for works in such substations as to whether any new equipment should maintain the existing control philosophy or whether the substation should be brought in line with this specification. Where such switches are installed, double point status indication shall be provided to NCC.
Control safeguards and safety interlocks, including those associated with engagement or operation of any manual operating handles or levers shall be as outlined in the relevant plant functional specification. Where status indication of such safeguards is available, control

unavailable indication shall be brought back to NCC in series with the control isolation switches outlined in section 5.3.1.3.

6 Protection and Automatic Control

6.1 Protection

Protection tripping and automatic reclosing shall be provided in accordance with the project specific Protection Specification and associated protection elementary drawings.

6.2 Check Synchronising System

Station synchronising requirements will be confirmed on a project specific basis and outlined in the project specific Protection Specification.
The synchronising facility shall be installed in the Control room in accordance with section 5.2.1.12.

Table 7: Check Synchronising Switches and lamps

Label	Switch /Lamp
14	Synchronising mode selection push buttons; • Direct Close • Sync Close • Sync Transfer (if required) • Stop
15	Synchronising Instruments
16	Synchronising mode selection lamps; • Direct Close • Sync Close Sync Transfer (if required) • Controlled Synch
17	Controlled Sync Bay Selection switches (RTU only)
18	Controlled Sync selection switch,
19	Controlled Sync Close command switch,
20	Controlled Sync condition indication lamps; • Voltage matched • Phase angle matched • Frequency matched • Sync Relay Ready to Close

The controlled sync close facility shall consist of a set of suitably scaled self-powered analogue synchronising instruments, comprising:

- Double voltmeter. Showing primary voltage in kV. Typical scale to 150 % of nominal voltage across a 90^o rotation. Dials should be arranged such that maximum and minimum on each scale are aligned.
- Delta voltmeter. Showing voltage difference as a percentage of nominal voltage. Typical scale ±20 % across a 240^o rotation
- Double frequency meter showing frequency in Hertz. Typical scale of 47 to 53 Hz across a 90^o rotation. Dials should be arranged such that maximum and minimum on each scale are aligned.
- Delta frequency meter[27]. Showing difference in frequency in Hertz. Typical scale ±0.5 Hz across a 240^o rotation (Maximum acceptable scale is ±1.0 Hz by agreement). Meters showing difference in frequency as a percentage of 50 Hz shall not be used.
- Synchroscope with 360^o rotation and a clear marking showing the point of zero phase difference.

The use of digital meters is not acceptable due to issues with response time and “jitter”.
The reference and incoming voltage shall be displayed on these instruments following selection of the controlled sync close mode. These Instruments and signals shall be clearly visible to the operator carrying out the synchronising operation.

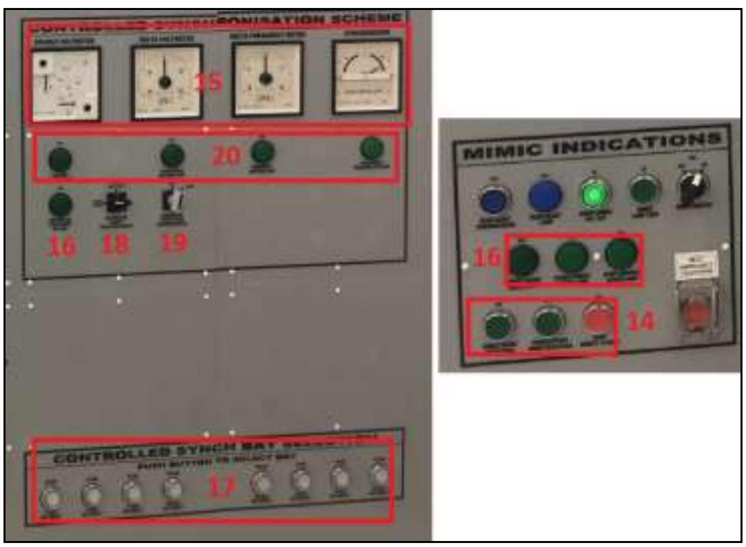

Figure 12: Check Synchronising Switches and Indications

[27] Although common in existing installations, vibrating reed type dual frequency meters are no longer acceptable for new installations.

6.2.1 Synchronising System Functional Requirements

Selection of “Controlled Sync Close” mode shall be from a latched 2 position switch.
This switch shall be located near to the synchronising instruments.
This switch shall normally be in the “Check Synch” (Off) position which shall allow all other modes to be selected by the push buttons outlined above (or via HMI in **SCS** controlled substations) . In the “Control Sync close” (On) position, it shall not be possible to initiate any other mode of operation. Operation of the switch shall not interrupt any mode which has already been initiated.

Once Controlled Sync Close mode of operation has been successfully selected a lamp shall be illuminated (or indication provided on the HMI for SCS substations). NCC shall have double bit status indication of this mode being selected.

For **RTU** controlled substations, the “Direct Close”, “Sync Close” and “Sync Transfer” shall be selected from non-latching illuminated push-buttons located in a prominent position. A non-latching illuminated “Stop” push button shall also be provided. This pushbutton shall fully reset the check synchronism system. The use of non–illuminated push buttons and separate indicating lamps is also acceptable.

Selection of “Direct Close”, “Sync Close”, “Sync Transfer” and “Controlled Sync Close” mode shall be via the central HMI in **SCS** controlled substations.
Selection of Controlled Sync in **SCS** shall inhibit all Direct and Check Sync operations from the SCS HMI.

There shall be clear indication of the current selected mode of operation at all times. This shall be adjacent to the selection push buttons and also brought back to NCC.
Note: It shall **not** be possible to select more than one mode of operation simultaneously.

It should be noted that in **RTU** substations “Sync Transfer” is a subset of the “Sync Close” mode which must be selected before a “Sync Transfer” can be initiated.

In **SCS** substations “Sync transfer” can be directly selected
Remote control (in parallel with the local control described above) and status indication for “Direct Close”, “Sync Close” and “Sync Transfer” shall be provided to NCC.

Once the process has started for closing a particular circuit breaker, the system shall ignore any attempt to close any other circuit breaker (Note: the system shall not inhibit any auto-reclose command as these are not routed through the synchronising system unless specifically requested in the project specific protection specification).

The synchronising system shall incorporate the following functions:

1. The system shall issue an alarm and prevent initiation of a further CB close operation if the voltage selection relays have not reset within 2 seconds of a system reset condition.
2. The system shall reset if a CB control switch or control sync switch is not operated within 60 seconds following “direct close” or “sync close” selection.

3. The system shall reset if the circuit breaker does not close within 60 seconds following operation of the discrepancy control switch.
4. The system shall reset if the generator Transformer CB does not close within 30 minutes following the operation of “Sync Transfer” either locally or remotely.
5. The system shall reset automatically following issue of a close command to a circuit breaker.
6. In control sync mode the system shall reset if the circuit breaker does not close within 15 minutes of selecting control sync mode and making bay selection. Bay selection would then need to be repeated to re- initiate.

6.2.2 Sync Close modes

6.2.2.1 ‘Direct Close’ Selection

This is the direct manual control. In this mode a close command is directly applied to the circuit breaker without any check that the voltages on each side of the circuit breaker are in synchronism. Selection of this mode is followed by operation of the appropriate circuit breaker control and discrepancy switch.

6.2.2.2 ‘Sync Close’ Selection

This is the automatic check-synchronising mode. When this mode is selected the voltage, frequency and phase angles on either side of the circuit breaker are automatically checked and a close impulse is only released when the check parameters agree within certain tolerances. If voltage is detected on one side of the CB only, then the synchronising close operation shall be blocked.

Selection of this mode shall be selected first followed by the operation of the appropriate CB control and discrepancy switch to automatically select the appropriate reference voltage. See section 6.2.3 for further details on voltage selection requirements.

In general, auto-reclosing is independent of the check synchronising scheme but there are some circumstances whereby the reclosing is routed via the check synchronising scheme. Requirements will be outlined on a case by case basis in the project protection specification.

6.2.2.3 ‘Sync Transfer’ Selection

This mode shall provide the Customer/Generator synchronising equipment with the necessary busbar “reference” VT output, the customer bay “incoming” VT output, and CB sync close control to allow the Customer to synchronise across the HV side of the CB.

For **RTU** substations, this mode can only be selected when the overall system is in Sync close mode. For **SCS** substations sync transfer can be selected directly.

This mode shall also disconnect/disable the start command input, closing output (paralleling order) and voltage signals (incoming and reference) from the transmission system synchronising IED and instrumentation.

Once Sync transfer is selected (either locally or remotely) the scheme shall allow the Customer 30 minutes to Sync across the Transmission Grid circuit breaker (switched DC 220 V positive and DC 220 V negative supply) otherwise the scheme will reset.

6.2.2.4 'Controlled Sync Close' Selection

This mode is required to synchronise 2 parts of the network which have become separated (Island mode).
After selecting this mode, the operator must select the Circuit Breaker to be closed using the appropriate bay selection switch.
It shall not be possible to select more than one Circuit Breaker at a time.

For **RTU** controlled substations selection shall be done via the bay selection push button switches. Confirmation of the selected circuit shall be provided either via the use of illuminated pushbutton switches or separate pushbutton switches and indicating lamps.

For **SCS** controlled substations, the bay selection shall be done via the SLC HMI. The SCS system shall control the voltage references passed to the synchronising instrumentation. Separate indication of the selected circuit is not required at the control sync cabinet as it is available at the central HMI which should be adjacent.

The Operator must then match the voltage, frequency and phase angles of the 2 parts of the network (using the Synchronising instruments), and then issue the close command at phase coincidence.
Lamps are required to indicate when the different conditions have been met: voltage, angle, frequency matched and check release. These lamps shall be driven by output contacts of the synchronising relay.

The close command of the CB shall issue from the dedicated "Controlled Sync close" command switch (i.e. not the individual Circuit Breaker discrepancy switch) and be routed via the synchronising IED. The command switch shall be a dual action push and turn with spring return rotary type. These shall be similar to the command switches as outlined in 1.2.3, but with the status indication/discrepancy/flicker and CB open functionality unused.

6.2.3 Voltage selection

A voltage selection facility shall be installed to ensure that the appropriate reference voltage signals are presented to the synchronising instrumentation and IED.

The voltage selection shall take account of the position of all disconnectors, and in the case of Coupler/Sectionaliser bays, circuit breakers, and shall have a consistent approach to ensure that the voltages are representative of the voltages present on either side of the circuit breaker.

For both **RTU and SCS** substations R-S line voltage shall be used.
For modifications in existing substations, consistency with the existing voltage selection design shall take priority over this specification unless specifically requested by EirGrid. The use of phase voltage shall only be accepted by agreement at legacy substations depending on the requirements of existing synchronising IED (both EirGrid/ESB and customer devices).
Under no circumstances shall the voltage selection cause VT secondary wiring to be shorted or paralleled, even momentarily.

For **RTU** substations voltage selection shall be initiated by either;

- Selection of controlled sync close and associated bay selection, or
- Selection of any other mode (excluding direct close) and close operation of the circuit breaker control and discrepancy switch or sync transfer.

For **SCS** substations the busbar reference voltage shall always be available to the BCUs using a hardwired busbar reference voltage bus (or buses in the case of double busbar configurations) between the BCUs.
Priority for which BCU provides the reference voltage onto the bus shall be determined using graded time delays in addition to conditioning based on primary plant and VT status.

6.2.3.1 Convention

The following convention shall be implemented in all new installations to ensure consistency.
It should be noted that alternative arrangements may be in place in existing substations and care should be taken to ensure any modifications or extensions are consistent with the operation of the existing scheme.

The terms “incoming” and “reference” refer to the voltage signals presented to the instrumentation and IED as representative of those on either side of the breaker.
The orientation of left and right within the substation shall be as outlined in functional specification XDS-GFS-00-001 or an alternative agreed site specific convention.
Once initiated, the voltage selection scheme shall connect the VT on the selected circuit to the “Incoming” voltage busbar. This shall be conditioned by the position of any disconnector between the VT and the circuit breaker (e.g. on GIS installations) and shall also prevent any other VT signal from being connected in parallel.
The scheme shall use a busbar image arrangement to determine which circuit VT would be appropriate to use as a reference voltage.

Selection of VT for reference voltage shall also be conditioned to ensure that a circuit with a faulty VT is not selected. This shall be achieved using a system to detect voltage presence. For **SCS** installations this shall be implemented using a “VT live check” functionality whereby the BCU checks for voltage on the respective analogue input.
The use VT secondary MCB status indication to condition VT selection shall only be implemented to maintain consistency in legacy substations and is subject to the VT MCB status indication not being a grouped signal with other VT MCBs.
One of these shall then be automatically selected based on priority cascading from the left. This shall also prevent any other VT signal from being connected in parallel.

For couplers and sectionalisers the reference voltage shall be taken from a circuit to the left (or A bar on coupler) and the incoming voltage from a circuit to the right (or B bar on coupler).
The scheme shall not allow the same VT to be used for incoming and reference signals.

As an example, the typical order of preference to select a busbar voltage reference for a feeder circuit breaker (F3) connected to the A1 bar on a standard 220kV ring substation would be F7 bay VT if VT available and CB and DA closed (& DL if VT outside the DL as per GIS), followed by F5, F1, then F2, 4, 6 etc. subject to the A1 & A2 bars being coupled.

For **SCS** substations the voltage selection shall be integrated into the SLC logic with the relevant reference voltages (from the respective BCUs) being passed to the synchronising cabinet if required for controlled sync closing.

6.3 Voltage Control

Automatic and manual voltage control shall be provided in accordance with the project specific Protection Specification and associated protection elementary drawings.
Additional requirements may also be found in the relevant plant functional specification (e.g. Transformer).
As there are different requirements for TSO and DSO Transformers, the Customer may seek confirmation of requirements for a particular transformer from EirGrid. The Customer shall comply with all relevant DSO requirements additional to those referenced in this specification.

6.4 CT And VT Secondary Circuits

All instrument transformer windings from each single phase instrument transformer shall be cabled to marshalling boxes adjacent to the instrument transformer or to a bay LCC. Marshalling boxes should be installed at a reasonable height, i.e. the bottom of the box should be no more than 1.2 m above ground.

Each instrument transformer winding shall be earthed at only one point.
Where the winding crosses an interface boundary, the earth shall be located in the Interface Cabinet in the HV control building. Spare CT cores should be shorted out in the marshalling box/kiosk and earthed. The other CT cores shall be earthed at the first cabinet where it connects to a numerical device.
Earthing of any CT secondary wiring crossing the Customer interface boundary shall be agreed to ensure that only a single earth is applied.
Spare VT windings should be wired to MCB's (and suitable terminals for future onward connection) in the bay LCC/marshalling box.
Marshalling boxes shall be lockable to prevent unauthorised access.
All CT and VT wiring within cabinets, kiosks panels, etc. shall be designed according to the block diagram in Figure 1313. Note that these are minimum cable core sizes and larger sizes may be required in accordance with Instrument Transformer suitability calculations based on cable lengths and the protection and metering devices and as outlined in the project specific Protection Specification.

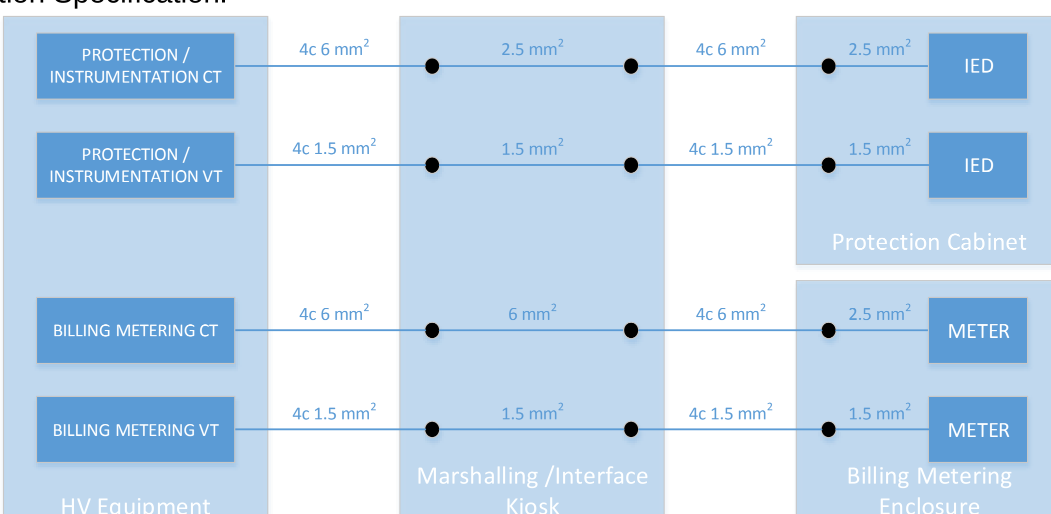

Figure 13: CT & VT Secondary Wiring Block Diagram

For details on CT and VT terminal requirements refer to the latest revision of EirGrid specification XDS-GFS-07-001.

VT star-connected and open-delta connected circuits for protection and (non-revenue) indication metering shall be protected by MCBs with characteristics as defined in the protection elementary drawing for the specific device used. These shall be located in the LCC/marshalling box. (Note: this is in addition to the 16 A fuses incorporated within the VT which protect the cable before the MCB which are not shown in Figure 1414 for simplicity).

The star connected VT MCB's shall be fitted with auxiliary contacts (1 N/O, 1 N/C), one to block inappropriate operation of impedance protection relays and one for signal purposes.

Billing meter VT circuits shall be protected by the 16 A fuses in the primary plant and 2 A fuses in the marshalling box/LCC and within the metering cabinet.

VT star-connected circuits may be connected to both protection and (non-revenue) metering systems. The VT Circuits shall be routed via the protection cabinets where the protection device shall be connected with no additional fusing or MCB. Any winding also used for instrumentation or metering will be sub-fused for each metering system e.g. indication metering, SCADA metering, disturbance recorder etc. This shall be achieved using terminal type fuses (typically 2 Amp) as outlined in EirGrid functional specification XDS-GFS-007-001.

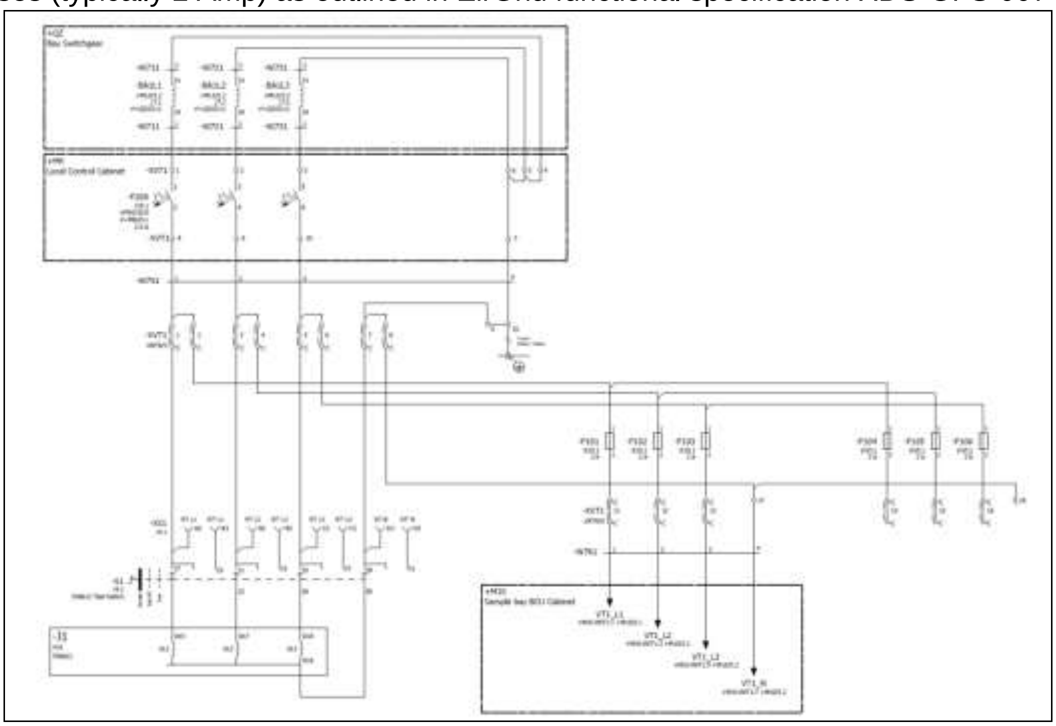

Figure 14: Sample schematic of VT sub fusing

All CT circuits for billing (revenue) metering shall be wired with at least 4x6 mm² NYCY cables. All VT circuits shall be wired with at least 4 x 1.5 mm² NYCY cables. Rating calculations shall be performed to confirm suitability and submitted to EirGrid for review.

6.4.1 Billing And Metering

Dedicated CT and VT windings shall be used for the main and check billing (revenue) meters. There may be instances where there are a limited number of CT / VT cores and check metering may be shared with protection cores, which shall be agreed with EirGrid.

Billing metering CT and VT circuits shall be implemented as in the block diagram in Figure 1313.

The circuits shall be marshalled in dedicated marshalling boxes which will be fitted with a seal. Alternatively a Plexiglas box with seal can be installed in the CT marshalling or customer interface kiosk to segregate the revenue metering circuits.

Additional requirements for billing metering in GIS substations are outlined in EirGrid specification XDS-GFS-25-001.

The orientation of the CT/VT cabling from the CT/VT cores to the metering cabinet shall be installed in order to meter the export generation to the transmission network.

See section 12 for further details.

Note: For demand connections refer to project specific requirements.

6.5 Relay Selection and Application

6.5.1 Main Protection Relays

The following should be noted in relation to application of protection elementaries.

- The customer shall be responsible for confirming that they are referencing the correct drawing and revision for all applications as outlined in the project specific protection specification.
- All main protection and control relays (IED) shall be per the specific product order codes outlined in the project specific protection specification and associated protection elementaries.
- The elementaries define the requirements for I/O allocation, test sockets (including pin details) and test switches.
- The elementaries define the parameters for confirmation of Instrument Transformer suitability.
- Interface connections to switchgear or associated equipment/bays are indicative and shall be adapted by the Customers designer to accurately reflect the specific substation equipment and interfaces.

6.5.2 Auxiliary Relays

This section refers to auxiliary relays. Auxiliary relays shall be selected based on the particular scheme requirements. The following general rules shall apply:

- The use of interposing relays shall be minimised as far as possible. Unless formally agreed otherwise, interlocking, plant position indication and inputs to protection IEDS shall operate directly from plant auxiliary contacts.
- All relays shall be from reputable suppliers with proven service reliability.
- All contactors must be constructed as a simple AC or DC coils without any electronic control circuits.

- All relays used in tripping circuits[28] or other time critical applications shall be high speed type with a maximum operate time of 10 ms. These must be withdrawable form a fixed base without affecting wiring. (Example 7PA26 or equivalent)
- Functionality and rating of all coils and contacts shall be suitable for the respective application.
- Construction of the relay shall eliminate the possibility of unwanted operation of the contacts during plugging/unplugging due to squeezing the relay casing. (Signal, position indication and similar circuits example Schrack MT321 or equivalent 11-pin relay.)
- All DC coils must have a back-emf overvoltage protection (internal diode, snap on or a freewheel varistor) based on OEM recommendations.
- Coils shall not be connected in parallel with the binary inputs of IEDs.
- Where appropriate, relay coils shall be suitably rated for continuous operation.
- All identification tags for cables across the station shall be white background black font.

[28] Note: The use of trip repeat relays shall be kept to a minimum. It should be noted that there is a distinction between an operator Open command and a trip.

7 INTERLOCKING

7.1 GENERAL

The interlocking conditions are designed to prevent:

- the operation of disconnectors under load.
- the operation of earthing switches on to a locally energised circuit.
- energising a circuit onto a local earth.
- Unintended or unwanted switching sequences.

The purpose is to ensure the safety of personnel and to preserve the integrity of the substation.

An interlocking scheme must be designed so that it is fail safe i.e. the failure of any part of the scheme must not allow an inadvertent operation.

Primary contacts shall be used from the high voltage switchgear for position indication to the interlocking scheme. If auxiliary relays are required to be incorporated in the interlocking scheme, they shall be operated in a fail-safe mode. The use of auxiliary relays to provide position indication must be evaluated on a case by case basis and must be approved by EirGrid.

Local mechanical operation should also be subject to the same interlocking conditions as electrical operation.

It shall not be possible to inadvertently store a switchgear open or close command through hold-on circuits or other means beyond the end of travel of the initial command.

Please refer to the substation specific interlocking requirements for the interlocking conditions for the installation.

For contestable works this will be provided by EirGrid, for non-contestable works it will be provided by ESBN.

Plant specific safety interlocks (e.g. low gas) shall be as outlined in the relevant plant functional specification.

7.2 RTU CONTROLLED SUBSTATIONS

All electrical interlocking shall be hardwired.

A separate dedicated DC 220 V interlocking supply is required for station interlocking requirements.

A dedicated interlocking DC 220 V supply is to be used for each primary voltage level.

7.3 SCS CONTROLLED SUBSTATIONS

For SCS installations please also refer to EirGrid functional specification XDS-GFS-24-001.

For **SCS** designs, a dedicated position indication DC 220 V supply is used for each bay[29].

In-bay interlocking requirements shall be implemented via the BCU software. Bay control units shall have an associated interlock bypass key-switch, which bypasses the bay control unit internal interlocking for each bay. This is required for maintenance or in the event of failure of the system, (communication network, as opposed to the substation computer). These are

[29] In bay interlocking utilises the position indication for the BCU and there are not separate PI and interlocking inputs.

labelled “Interlock Bypass” switch with two positions “Normal” and “Bypassed”. This switch shall be maintained in both positions and the key can be removed in “Normal” position only. Keys shall be interchangeable within all bays of the substation. Individual alarms from each bypass switch shall be provided. Only local operation at the bay control point is permitted while the interlocking is bypassed.

Interbay interlocking shall be hardwired in all cases. As per RTU substations (see section 7.2) this shall be on a dedicated interlocking supply per primary voltage level.

8 Monitoring, Alarms and Indications

Monitoring of the substation high voltage equipment shall be possible from separate control point locations as outlined in section 4.2. Indications at these control points are also outlined in sections 5 and 6.

This section of the specification deals with the specific requirements for communications to NCC. ESB Networks are responsible for providing specific requirements for the NDCC RTU and associated connections.

8.1 General

EirGrid will be responsible for terminating all cables at the RTU and MDF cabinets (Note: this is carried out by ESB Networks Telecoms on behalf of EirGrid).

Refer to the ESB Networks Telecoms Cabling 110 kV Overview drawing listed in section 2.1.

The Customer shall be responsible for terminating all CT and VT cables at the telemetering and energy metering cabinets.

ESB Networks Telecoms (on behalf of EirGrid) will supply and install an EirGrid Telecommunications Interface Enclosure (ETIE) in the control room. The ETIE will be the marshalling point for Grid Code control commands/signals/measurands etc. These signals should be connected via the Customer Interface Cabinet in the control room. EirGrid will supply and terminate (at both ends) the cables between the ETIE and the SCADA equipment enclosures (Telemetering, NCC RTU and MDF).

The Customer shall supply and terminate (at both ends) the cables between the ETIE and the Customer Interface Cabinet.

Each of these cables must be dedicated to one particular function i.e. remote control, status indication, alarms or mA analogue signals.

All of the mA analogue signal cables to SCADA shall be multiple twisted pair cables (solid cores with minimum wire diameter 0.75 mm).

Dedicated terminal blocks suitable for paired cable shall be used (KRONE LSA-PLUS 10 pair blocks or agreed equivalent shall be accepted).

NCC control, position indication and signal cables must be multicore screened cables. Control and PI must be provided on separate cables.

0.2 mm^2 multicore DEFSTAN is the preferred cable type for position indication and alarms.

0.5 mm^2 multicore DEFSTAN is the preferred cable type for commands[30].

Suitable core numbers (typically 12 core for position Indication and 36 core for alarms) should be used. For further details of cable requirements refer to EirGrid functional specification XDS-GFS-11-001.

EirGrid will also install and connect the telecoms DC 48 V battery and charger. The battery will be located in the substation battery room.

Sufficient space should be allocated in the battery room for the DC 48 V battery. Sufficient space should be allocated in the control room for all SCADA cabinets. A layout drawing indicating the positioning of all cabinets in the control building must be submitted to EirGrid for approval prior to the construction of the control building.

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[30] This is assuming the legacy Allen Bradley recloser control relay is not being used. Further details for suitable cables for legacy installations can be requested from EirGrid.

For additional guidance refer to the ESB Networks Telecoms drawing 110kV station SCADA Cabling overview (drawing reference: 110KV-STATION-TELECOMS Sheet 1).
A single dedicated AC 230 V MCB for each Telecoms 48 V battery charger and 4 dedicated DC 24/48 V MCB's for the SCADA system to be provided. Please refer to the latest version of EirGrid functional specification XDS-GFS-10-001 for further detail.

8.1.1 REMOTE CONTROL

A SCADA advance warning facility shall be provided. This shall allow the control centre to energise an **outdoor** audible alarm (external pre-switching siren to warn anyone in the station compound of the imminent operation of a circuit breaker or disconnector by remote control). The audible alarm shall be initiated from a DC 24/48 V remote control command and shall be held on for a period of time by an adjustable timer. Sounders which require an additional AC auxiliary supply are acceptable.
See section 8.1.3 for further details.

8.1.2 STATUS INDICATION

Position indication (ON and OFF) of the CB, all disconnectors, alarms and measurands shall be provided back to NCC regardless of the position of the Sub-remote control (or any other control isolation switch) switch.
Status indication to NCC and NDCC shall be provided by independent volt free contacts. It is permissible to group one side of potential free contacts into a common return where it is practical to do so.
Where available, status indication of all switches or facilities (e.g. operating handle interlocks) that can prevent remote operation of the plant shall be provided back to NCC.
3 levels of indication shall apply

- Station remote control unavailable
- Grouped indication per bay. This includes bay sub remote, bay remote (at LCC) and individual plant control (only for items where control from NCC is possible)
- Individual indication for Black start, Auto Reclose and Special Protection System unavailable

Refer to the substation specific outline design document and EirGrid Signal List for a list of all status indication requirements.
Position indication shall be required from additional items of Customer switchgear. EirGrid will confirm requirements upon receipt of the Customer single line diagram.

8.1.3 ALARMS

A normally open volt-free contact shall be provided to the SCADA systems for indication of "STATION GENERAL ALARM" which shall close whenever any alarm is generated in the substation. Both NCC and NDCC shall get this alarm.
A normally closed contact shall be provided to a back-up system (i.e. Cello[31]) which shall open whenever any GSA is generated in the substation.

[31] All equipment & cabling required for the Cello alarm to NDCC shall be provided and installed by ESB Networks Telecoms.

The backup unit shall also monitor for loss of supply from any of the station DC (24/48 V) supplies necessary for operation of the alarm system.
Both internal and external audible alarms which sound whenever an alarm is generated shall be provided. An internal lamp/visual indication (red) shall illuminate whenever an alarm is generated.
The internal lamp and alarm shall sound for a loss of DC supply that is used for the alarm circuits.
The external alarm shall time out after 30 seconds. Provision shall be made for a test input to allow operation of the alarm system to be tested locally and from the NCC . Provision shall be included for failure of an alarm unit to generate one local and two remote alarms.
The siren must have a different tone for each of the following events:

- SCADA advance warning (pre switching)
- General station alarm (GSA)
- Blue alert (where required)

An “External Siren On/Off” switch shall be provided to disable the external siren for GSA events only. Status indication of the switch shall be brought back to NCC. This shall be located on the SLC cabinet in **SCS** substations and on the Backup Alarm cabinet in **RTU** substations.
Facilities to allow the "silence alarm" and "signal reset" function to be implemented from both local push-buttons and from NDCC SCADA shall be provided via installation of NDCC RTU.

8.1.3.1 Event Recorder

For **RTU** controlled substations the signalling system device consists of an Event Recorder unit housed in a dedicated cabinet. Datac type Alarm Annunciator Panels shall only be used by agreement with Eirgrid for modification works in legacy substations.
The system design shall incorporate the following features.
All available signals shall be connected to the local signalling system. A substation signal list shall be provided by the Customer and all signals shall be programmed in the Event Recorder by the Customer.
Provision of all alarms to the local signalling system and to the SCADA system shall be by means of interposing relays connected to each alarm source. Unless as part of the extension of an existing alarm system, parallel indication shall not be achieved through the use of blocking diodes or diode type terminal arrangements.
The interposing relays shall have 3 normally open volt free contacts which will enable up to 3 separate locations to get each alarm simultaneously. These interposing relays shall have a test facility.

- NCC via KRONE LSA-PLUS block (using RTU supplies)
- Event Recorder via KRONE LSA-PLUS block (using Event Recorder supplies)
- Backup system (dedicated backup supply)

Alarms shall be displayed on a terminal/ screen located at the desk.

All alarms must be GPS time stamped to indicate when they became active and when they were cleared. Sufficient capacity shall be provided to cater for the ultimate development of the substation and for the possible installation of duplicate protection in the line bays.

The arrangement of DC 24/48 V supplies used for various inputs into the alarm system shall be designed so as to provide segregation between alarms from the individual feeder bays and other systems which justify a segregated supply e.g. battery supervisory alarms and various miscellaneous alarms. Individual MCBs shall be used for the alarm circuits per segregated group. Care shall be taken to ensure that the correct group negative is used in the interposing cabinet.

EirGrid only require certain alarms to be brought back to NCC. These will be outlined in the project specific EirGrid signal list. The Customer shall bring any available signals (based on specific plant installed) not on the signal list to the attention of the EirGrid Client Engineer for consideration.

All NCC signals shall be presented at Marshalling Distribution Field (MDF) to facilitate alarm selection, grouping and onward connection to NCC RTU.

NDCC signals will be detailed separately in the NDCC specification. Indication of alarms to NDCC shall be via gateway fed from the Event recorder

A single Datac type Annunciator shall be used as backup system. Alarms shall be grouped into 2 signals per bay (“Alarm” and “Trip” events).The backup system shall activate the General station alarm and sounders.

8.1.3.1.1 Notes on AAP cabinets (Legacy **RTU** only)

The annunciator unit must be capable of grouping alarms on a bay by bay or functional basis. The alarm text must be easily legible by an operator and the unit must be capable of displaying sufficient text characters to cater for the signal text. The alarm unit must be capable of differentiating between active and cleared alarms – all alarms must remain on the annunciator unit until they have been manually cleared by an operator.

If there is more than one alarm annunciator unit, the first unit fail shall be connected to a spare channel of the second unit and the second unit fail to be connected to spare channel of the first unit. Any subsequent units shall be daisy chained in the same fashion. The unit fail shall also indicate to the RTU and initiate the GSA sounder.

NDCC signals shall be presented to the NDCC RTU via serial connection using data cable from the alarm panels to Modbus port on NDCC RTU. This shall be a permanent serial link and shall not make use of ports intended for temporary or commissioning purposes.

8.1.3.2 SCS

Except where outlined otherwise, the Alarm and indications signals shall be routed through the Bay Control units and Station Level Controller.

The SLC shall be used to set and reset the GSA. Local test button shall operate via the SLC. The local GSA reset pushbutton shall provide input to the SLC in addition to operating directly on the GSA circuit Outputs from the BCU’s shall also be brought back to operate a backup GSA trigger.

The GSA shall also trigger a Cello unit as outlined above. This shall utilise normally closed contacts to ensure that the GSA DC supply is also supervised.

For **SCS** substations a dedicated additional Cello unit shall monitor the SLC watchdog contact.

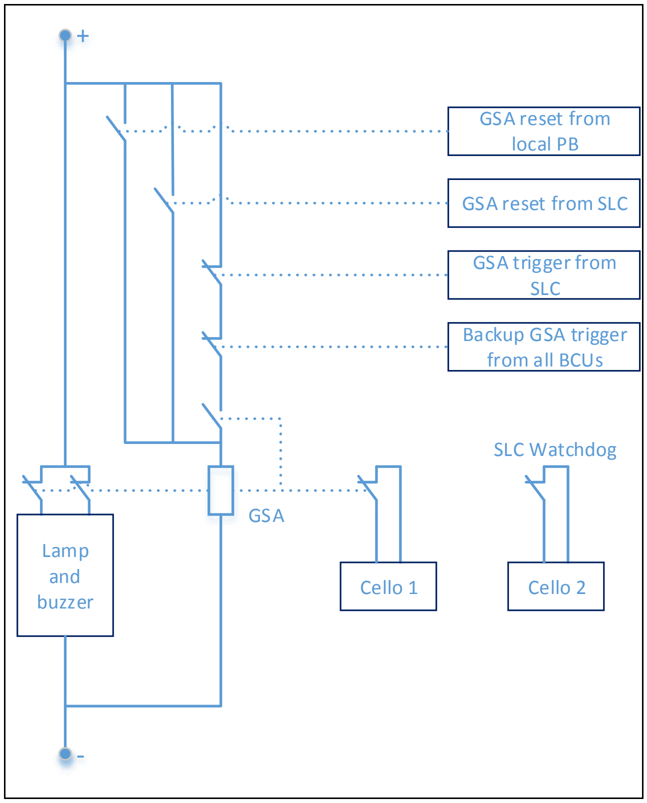


Figure 15: Simplified schematic of SCS duplicate backup monitoring arrangement

The following shall also be installed on the SLC cabinet

- External siren On/Off rotary switch (GSA only)
- Test alarm pushbutton switch
- GSA active lamp and reset pushbutton switch

8.1.4 Measurands

Refer to the station specific EirGrid (NCC)) and ESB (NDCC) signal list documents for a list of all measurand requirements.

8.2 Remote interrogation (IEDs)

8.2.1 General

Remote interrogation of the energy meters, protection relays and disturbance recorders is required by EirGrid.

All devices requiring a GSM (i.e. Cello units & metering) shall have their own dedicated antenna.

If required, the Customer shall install external high gain GSM antenna and associated antenna cable for the devices.

A single GPS antenna shall be shared by all equipment requiring GPS signal.

Details for protection and metering communications and time synchronisation shall be outlined in the project specific Protection Specification.

Remote communications capabilities shall be provided via ESB Networks Telecoms Wide Area Network (WAN.) (A 3rd Party PSTN telephone connection is required only where an ESB multiplexor (MUX) is not available.)

Where specified in the project specific protection specification, remote Interrogation of Disturbance Recorders and Protection Relays requires the installation of a dedicated Ethernet interface card in the WAN Multiplexor (MUX) cabinet. A Cat-5e cable shall then be connected from the MUX to the Disturbance Recorder/Remote Interrogation Cabinet.

(Note; MUX cabinet shall be supplied and installed by ESB Networks Telecoms. Remote Interrogation and Disturbance Recorder cabinets shall be installed by the Customer. Disturbance recorders and associated Local Storage Units (LSU) shall be free issued to the Customer by EirGrid).

8.2.2 Energy Metering

Remote interrogation of Main and Check Revenue Energy meters to the EirGrid central interrogation software is required nightly. A WAN or PSTN connection is required to the EirGrid Main and Check Energy meters. An EirGrid backup Vodafone GSM SIM card will be supplied by EirGrid with the Main and Check Energy meters; this is only subject to sufficient and reliable GSM Data coverage to the Energy meter cabinet. If required, the Customer shall facilitate the fitting of an external high gain GSM antenna and associated antenna cable to the EirGrid Energy Meters. The EirGrid Energy Meters shall be powered by the ESB Networks Telecoms DC 48 V supply.

8.2.3 Disturbance Recorder

Where outlined in the project specific protection specification, a disturbance/data recorder is required which shall monitor 110/220/400 kV voltages and currents on the specified bay(s). GPS synchronisation is required for the disturbance recorder clock (see section 8.2.5).

The Disturbance Recorder shall be powered from the station DC 220 V supply via a dedicated DC 220 V MCB. The Disturbance Recorder shall generally be housed within the Remote Interrogation cabinet.

8.2.4 Protection Relays

Control and indication from the protection devices shall also be provided in accordance with the project specific Protection Specification.

Fibre links will be required between the disturbance recorder/Remote Interrogation cabinet and the protection cabinets. For certain relay types, Fibre Optic-to-serial converters will also be required in the protection cabinets.

Line protection communications (e.g. GRL & TEBIT) requirements will be outlined in the project specific protection specification.

It should be noted that additional (duplicate) teleprotection is required on 220kV and 400kV network circuits.

8.2.5 Time Synchronisation

Certain protection relays shall be provided with IRIG-B time synchronisation from a GPS-synchronised time source. Further details shall be outlined in the project specific protection specification and associated elementaries.

A suitable clock and GPS antenna shall be installed. The GPS antenna shall have a lightning arrester installed where the antenna coaxial cable enters the building and must be adequately earthed.

As per section 8.2.1, where multiple services require GPS facility, these shall be consolidated into a single substation GPS receiver. This shall give HOPF 6870 timing pulse outputs using Universal Time Coordinated (UTC) time standard.

For **SCS** substations the SCS clock shall be acceptable for time synchronisation.

8.3 TELECOMS

This specification does not outline all substation telecoms requirements. Further details of telecoms equipment requirements can be provided by EirGrid on a project specific basis.

In general, there shall be separate communication paths to the NCC and ECC. Where only 1 route from the substation is available, this must be agreed with EirGrid and it must be capable of being switched between NCC and ECC.

Requirements for communication to the NDCC shall be outlined in the DSO specifications.

9 MAINTENANCE TESTING FACILITIES

Facilities shall be provided for in-situ testing of all meters and on load testing of protection relays by injection of test currents and voltages into the secondary circuits of CT's and VT's. It shall be possible to test a particular relay or meter independently of any other instrument connected in the same circuit. These facilities shall also enable secondary current and voltage outputs of CT's and VT's, respectively, to be measured.

In order to allow connection of portable test equipment without disturbing the small wiring, accessible test points in the form of test terminal blocks shall be provided at all cabinets containing CT and VT secondary circuits.

As per the relevant elementaries, the protection relays shall be connected through a test switch/ test socket combination. This test switch shall be suitably rated with sufficient contacts. Standard drawings (which shall be non-specific but relevant to all protection schemes of a given type (i.e. Lines or Cables etc) shall be provided by EirGrid. It will include the **mandatory** test socket arrangement. The test switch used must provide for automatic disconnection from the load and the short-circuiting of the CT secondary circuits. VT's shall be disconnected and open-circuited. It must be impossible during operation of the switch for CT's to be open-circuited or VT's to be short-circuited. Relay inputs and outputs shall be wired via the test switch in accordance with the elementaries. In general, relay outputs (including trip circuits) shall be disconnected in “Trip Off” and all relay inputs & outputs shall be disconnected in “Test”. All CT and VT terminals must be of the specified type. In the case of metering circuits and the disturbance recorder these terminals will provide adequate test facilities. Protection Relays shall have Trip Test switches (spring loaded and covered).

Note: There shall be only one test switch per protection relay. In all cases, but in particular where CT cores are shared between protection devices, the operation of the test switch on one relay shall not interrupt any other protection circuit. Such arrangement shall be subject to agreement by EirGrid.

Access is to be provided and permitted to EirGrid main and check revenue energy meters to facilitate testing, calibration and maintenance on site at the energy meter cabinet.
Access to the EirGrid energy metering cabinet, is subject to approval by EirGrid.
Breaking of EirGrid metering cabinet seals is subject to approval by EirGrid.

10 EIRGRID-CUSTOMER INTERFACE REQUIREMENTS

Please refer to project specific Wired Interface Schematic provided as part of Contestable Works Package or Committed Project Parameters.
For details on Kiosk, Cabinet and Terminal requirements refer to the latest revision of EirGrid Functional Specification XDS-GFS-07-001.

All LV signalling connections between EirGrid substation and the Customer[32] substation shall be routed through an Interface Kiosk. Note the following exceptions:

- Auxiliary supplies (AC or DC). These shall be connected directly between the relevant distribution & sub-distribution boards.
- Billing metering CT & VT circuits[33]

Where pulsed metering outputs are to be provided to the customer, these shall be routed via the interface Kiosk in accordance with the Wired Interface Schematic. Also, where there is MV/sub-metering, and the Energy Meters themselves are installed in the HV control room, MV CTs and VTs shall be routed via the interface kiosk. In all cases metering circuits shall be suitably segregated per section 6.4.1.

These kiosks shall be located at the physical boundary between the EirGrid and Customer substations i.e. in the fence or wall depending on the boundary).
Unless otherwise agreed, there shall be a separate interface kiosk for each high voltage customer circuit. The locations shall be agreed with EirGrid and shall be such that there can be no ambiguity regarding which primary interface connection the kiosk is associated with.

The kiosks shall be in accordance with EirGrid functional specification XDS-GFS-07-001.

[32] Does not apply to DSO interfaces.

[33] This is only applicable at Legacy substations. For all new transmission substations, the Customer Billing metering shall be installed in the EirGrid substation control room.

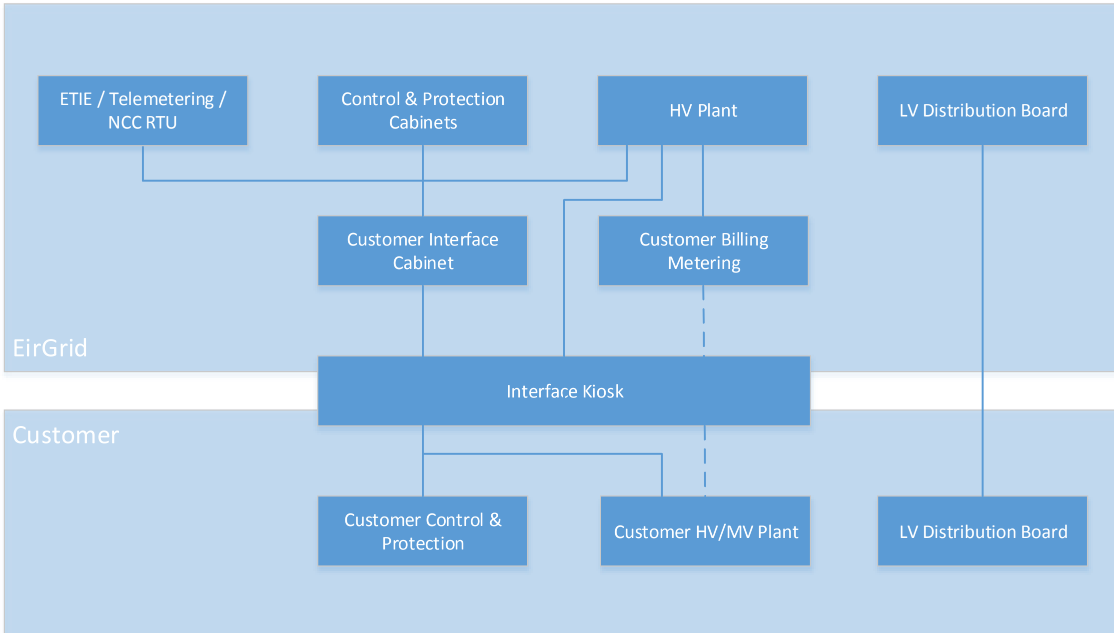


Figure 16: Customer LV Interface Block Diagram

The kiosk shall contain terminals on both sides to provide the interface connections between EirGrid and the Customer. The terminals shall be isolatable and incorporate test points per Eirgrid functional specification XDS-GFS-07.

The kiosk shall be separately accessible from the ESB and Customer sides and the terminal arrangement shall be identical on both sides to avoid any misunderstanding during isolation.
The kiosk is intended for cable marshalling and associated heating & lighting only.
The installation of other devices (e.g. relays, transducers etc.) within the kiosk is not permitted (any interposing relays shall be installed in the customer interface cabinet or suitable location on the customer side).
All DC connections crossing the interface boundary shall respect the following requirements in the compound where the supply is not derived. These requirements are symmetrical for supplies originating on either side of the interface:

- “Foreign” supply cabling shall be kept as short as possible. The DC circuit shall not extend beyond the interface cabinet on the 3rd party side[34]. Where signals from multiple devices at various locations are required, these shall be brought back to the interface and interposed.
- The use of multiple contacts for a given signal is acceptable provided all are within the interface cabinet
- “Foreign” supply cabling shall be secured against damage.
- Each supply shall be transferred across the interface at a single point (i.e. there shall not be multiple positive connections across the interface.).
- Supplies shall be used only for the intended purpose (i.e. connected to volt free contacts and no other derived functionality).

[34] A notable exception is interlocking circuits where direct auxiliary contacts shall be used as far as possible. Interposing of status indication for interlocking shall only be done with the express agreement of both parties.

- Receiving or input devices may be located in the interface cabinet or at other locations on the source side.

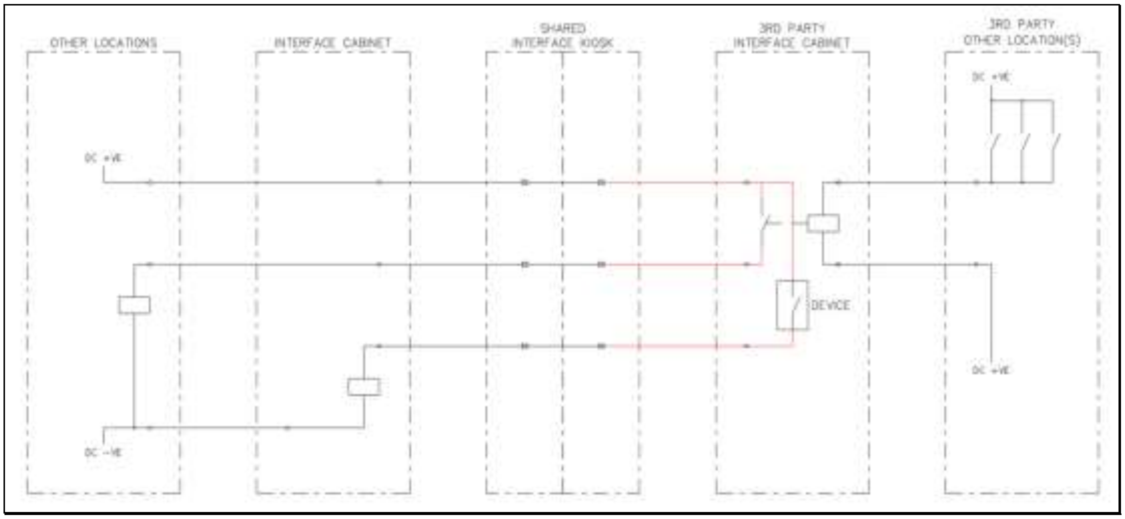


Figure 17: Illustration of acceptable use of supplies crossing customer Interface

Metering and instrument transformer cores being shared shall be routed directly to the Customer interface kiosk. All other interface connections to the interface kiosk shall be in accordance with fig 16 and the customer interface schematic.

The use of a separate customer interface cabinet per circuit is required in all new Transmission substations. It should be noted that where a common Customer Interface Cabinet is agreed in brownfield sites, full segregation between customer circuits is required to facilitate identification and isolation during maintenance. This applies to DC supplies, wiring and terminals.

It should be noted that a dedicated EirGrid RTU is required for IPP (including BESS or any other Flexible Generation or storage Customer) Customer interface signals in **SCS** substations. Use of the respective BCU for Customer interface signals is not acceptable[35].
For Demand Customers an RTU shall not be required for this purpose unless specifically requested in the project specific protection specification.

[35] Legacy conventional generation connections dispatched via the Electronic Dispatch Instruction Logger are a notable exception and do not generally require an additional dedicated RTU. In such cases, signals and measurands may be brought back to NCC via a dedicated interface BCU. It should be noted that changes to the nature of the generation may drive the need for a future installation of a dedicated RTU

11 Drawings And Information

11.1 General

A comprehensive set of drawings and associated documents shall be provided for the substation. The substation name shall appear in the title block of each drawing and the use of drawings common to several substations shall be avoided.

All drawings and documents must demonstrate that a quality assurance process has been implemented. Further details are outlined in EirGrid Functional specification XDS-GFS-00-001.

The Customer shall provide further details of their Quality Assurance process if requested by EirGrid.

To facilitate easy revision of drawings in the event of a feeder name being changed at a future date, feeder names should appear only on Single Line Diagrams and on the title block of schematic diagrams. This shall not affect the actual alarm text or bay equipment labelling requirements.

When the drawings are finalised, the Customer shall provide electronic copies of all drawings in pdf and native format to EirGrid.

Schematic drawings shall be on A3 size sheets. The drawings to be provided shall include the following information:

1 Schematic Diagrams
2 Wiring Details
3 Cable Schedules
4 Lists of Apparatus

11.2 Schematic Diagrams

Schematic diagrams will be required before commissioning to enable the following functions to be carried out and they shall be arranged accordingly.

- Manufacture & Installation
- To facilitate checking of method of operation.
- To indicate sources of supplies.
- To facilitate testing of circuits and equipment.
- To facilitate addition or alteration to functional circuits.

In the preparation and layout of schematic diagrams the following points shall be adhered to:

1 Schematics shall be provided to account for all substation equipment including all cabinets and cubicles and the associated cabling.

2 Schematics shall be prepared in accordance with IEC 61082-1

3 Particular attention shall be given to ensuring clear and unambiguous contents page(s) and schematic page numbering.

4 Symbols shall be in accordance with IEC Recommendation No. 60617.

5 As far as possible each circuit shall be shown complete on one sheet from source back to source, e.g. from battery positive - through all contacts and coils - to battery negative. Where this involves information included on OEM or other related drawings, cross referencing should be added to ensure all details are captured and guard against contradictory final records. Duplication should be kept to a minimum and simplified (or indicative) details included as required. Theses shall be clearly identified as such.

6 Each circuit shall clearly show source and voltage of supply so that supplies can be traced back to the respective distribution board and isolation point (i.e. not simply “Comms +ve” or “Comms –ve”)
7 Contacts may be shown detached from their associated coil or drive mechanism if clarity of presentation is thereby improved. Full cross referencing between device and contacts shall be included, and duplicate representation of the same contact shall be avoided as far as possible.
8 Cable numbers and cores to be clearly identified
9 A schedule of all devices showing used/spare contacts shall be included.
10 Associated cabinet layouts showing arrangement of equipment (Front, back & side elevations as appropriate) shall also be provided. This shall generally be incorporated within the schematic, but may be provided separately subject to agreement with EirGrid.

11.3 Drawings and information to be included before manufacture/purchase.

In addition to the particulars to be supplied in the completed Technical Schedules, information in the form of drawings, photographs, diagrams and descriptive literature shall be submitted to enable the merits of the equipment to be assessed. The minimum requirements in this regard shall be:

1 A proposed layout of control room including battery room.
2 Constructional details of control and protection cabinets.
3 Section drawings and Layout of Station.
4 Constructional details of proposed control cabinet.
5 Technical particulars of control and discrepancy switches, meters and converters, protection relays etc.
6 Schedule of auxiliary relays showing used/spare contacts
7 Representative sample schematic diagrams of control and protection illustrating proposed format and presentation.
8 Representative sample of wiring diagrams illustrating proposed format and presentation.
9 A proposed SLD including the long description of all Primary Relays.
10 Elementary diagram of proposed signal and alarm system.
11 Indicative Cable schedule including details of size, type and number of cores.

11.4 Drawings And Information To Be Submitted before installation

The following drawings shall be submitted to EirGrid in accordance the project specific SLD, protection specification, interlocking specification and protection elementaries.

1 Control room layouts.
2 Schematic diagrams of 110/220/400 kV switchgear operation and position indication with accompanying description of how each scheme works.
3 Schematic diagram of each protection scheme.
4 Schematic diagram of the signal and alarm system with accompanying description of its operation.
5 Details of maintenance testing facilities.

All documentation shall be updated and as-built versions provided based on the final commissioned state in accordance with EirGrid Functional specification XDS-GFS-00-001.

11.5 Protection Settings Request

EirGrid are responsible for preparing protection settings.
The Customer shall submit all necessary information required to prepare the settings using the EirGrid protection settings request template. This template shall be provided in the Contestable Works Package or be available by request via the EirGrid Client Engineer.
Customers should note that unavailability of protection settings can have significant time and cost implications on the commissioning and energisation works.

Settings requests shall be complete as far as possible.
Partial requests shall only be considered under exceptional circumstances and with agreement of the EirGrid Client Engineer.
Where the customer is not in a position to provide the complete information required in the setting request template, they shall clearly bring this to the attention of the EirGrid Client Engineer.
In such cases, it is recommended that the customer should discuss this with the EirGrid Client Engineer. Further details of the process and timelines associated with settings requests and other project delivery issues are outlined as part of the CWP/CPP.

12 Energy Metering Commissioning and DOF Procedure

This section of the specification relates to TSO supply (IPP) customers only. Energy metering for TSO demand customers is carried out by ESB Metering. Please refer to the relevant ESB specification for details of requirements for Demand Customers.

12.1 General requirements

12.1.1 PRE-INSTALLATION

12.1.1.1 CT configuration

The direction of exported active energy (MWh) as seen by the energy meter is determined by the polarity of the CT. Based on the standard station elementary drawings used by ESB and EirGrid; there are two possible configurations for the CT polarity:

1. Tail-fed single transformer configuration with P1 to the generator
2. Busbar-terminated configuration with P1 to the station busbar

These configurations are illustrated in the simplified single line diagrams shown in Figure 1818.
The convention for channel orientations in the meter is as per a busbar-terminated configuration i.e. P1 to the station busbar. To ensure channel orientation consistency across all energy meters, the CT tails are to be reversed for a tail-fed single transformer configuration.
CT lead reversal is to be completed inside the energy metering cabinet, between the CT terminals and the Test terminals, and is to be carried out by EirGrid's Meter Contractor.

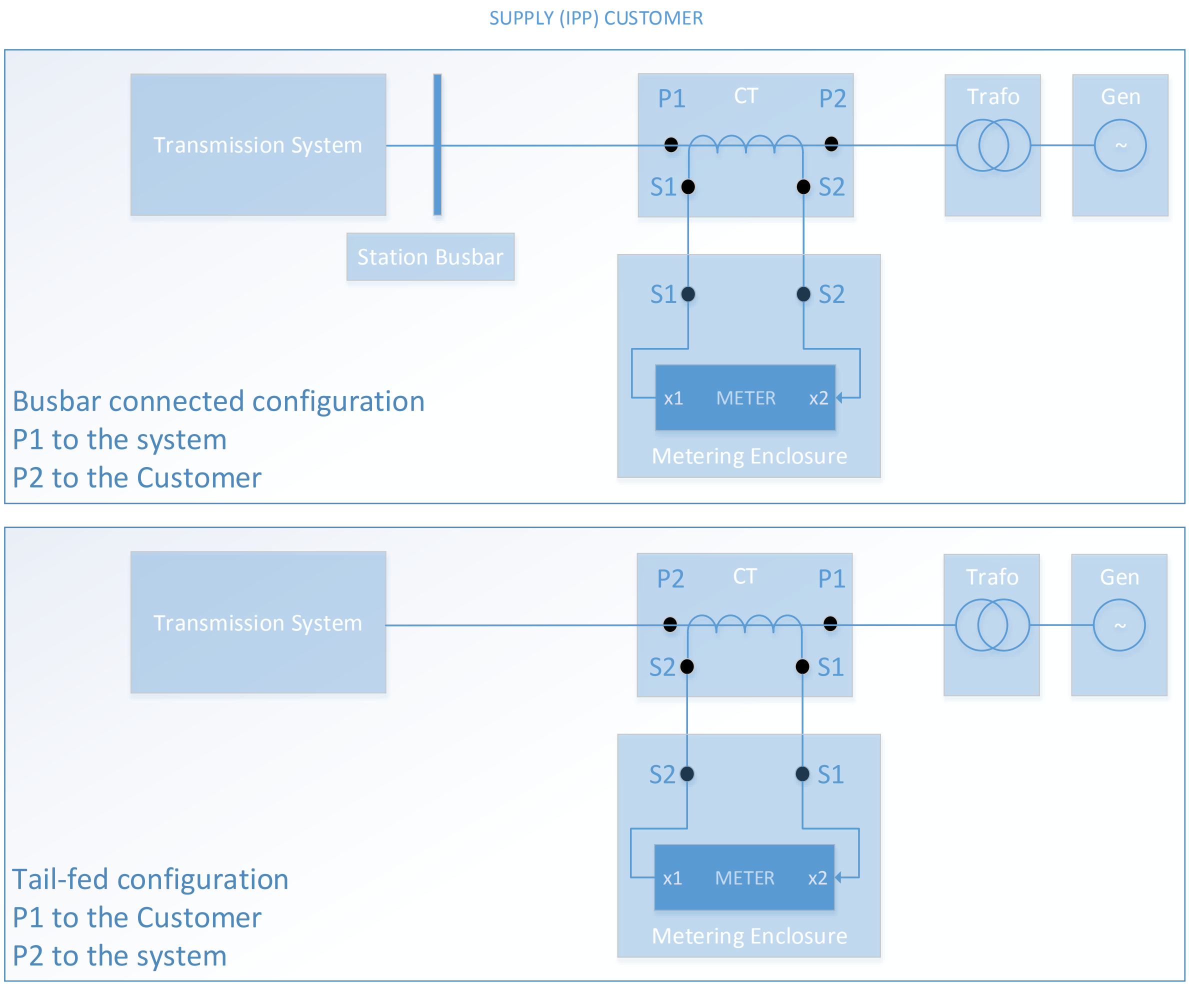


Figure 18: Configurations of Energy Metering CT Polarity

12.1.2 SCOPE AND DEFINITION OF RESPONSIBILITIES

EirGrid's Meter Contractor is responsible for the provision and installation of the energy metering cabinet and the energy meters, complete with modems and communication links to EirGrid Metering Department central interrogation system and all associated wiring within the metering cabinet with the exception of the CT and VT cabling external to the metering cabinet. If there is a requirement to reverse the CT tails, the wiring reversal is to be done between the CT terminals and the Test terminals in the metering cabinet and is the responsibility of EirGrid's Meter Contractor. EirGrid's Meter Contractor are to also place a label inside the energy metering cabinet indicating that the CT wiring has been reversed.

EirGrid's Meter Contractor are to seal all metering equipment, data collection equipment and associated modems and telephone links.

Termination of the external CT and VT cables to the terminations in the Energy Metering Cabinet is not the responsibility of EirGrid's Meter Contractor as it lies within the Station Electrical Contractors Scope of Work.

The approved station Commissioner is responsible for the end to end testing of all required metering signals from the primary terminals of the CT/VTs to the metering cabinet.

The station commissioner shall advise EirGrid's Meter Contractor and EirGrid Metering of the testing schedule to allow this end to end testing to be witnessed by EirGrid's Meter Contractor on behalf of EirGrid Metering.
EirGrid System Performance will issue the Energisation Instruction/s.

12.1.3 ISSUING OF DECLARATION OF FITNESS (DOF)

EirGrid's Meter Contractor will issue a DOF for the Energy Metering Cabinet to the station Commissioner / Electrical Supervisor / PICW for Contractor and to EirGrid National control centre. This DOF will specifically detail the status of the CT and VT input terminations (CT shorting links open/closed, VT fuses or MCB in/out.)
Where CT wiring reversal has been implemented in the metering cabinet, this is to be recorded in the Telecoms DOF.
The station Commissioner will then cover the overall EirGrid Billing Metering Scheme as part of the main DOF.

12.1.4 COMMISSIONING

The Telecom Commissioning Checklist will identify the links/shorting links on the VT/CT input into the Billing Metering Cabinet and ensure that these are left in the operational position following the full Billing Metering circuitry test.
Before the issue of the EirGrid's Meter Contractor DOF, the status of the Energy Metering VT/CT input circuits excluding those within the Energy Metering Cabinet will be the responsibility of the station Commissioner.
The station Commissioner is to advise EirGrid if any seals need to be broken for further testing.
ESB DOF Certificate, Instrument Transformer Commission Report and CT test reports are available from ESB Asset Management Services.

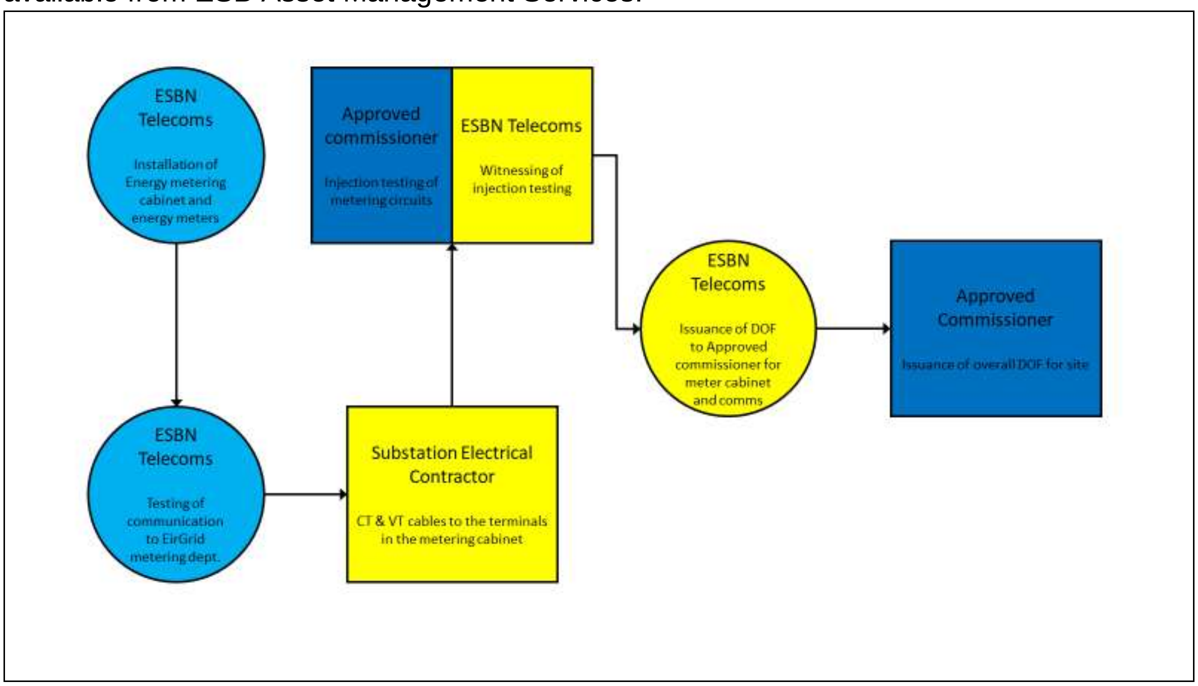


Figure 19: Work Flow Process and responsibilities for Energy metering installations

12.1.5 REQUIREMENTS

Prior to injection testing of the energy metering cabinet and energy meters, the station Commissioner shall advise EirGrid's Meter Contractor on the CT polarity configuration that will be used.

EirGrid's Meter Contractor, on behalf of EirGrid Metering, are to witness the injection testing carried out on the metering circuits by the Commissioner and EirGrid's Meter Contractor to issue the completed Energy meter injection test completion certificate to EirGrid Metering. (See Appendix 1: Metering test Certificates)

The station Commissioner shall send EirGrid the Instrument transformer Commission report and CT/VT test reports to metering@eirgrid.com, for CT/VT's connected to EirGrid Billing and Revenue meters.

12.2 SUB METERING

12.2.1 SCOPE AND DEFINITION OF RESPONSIBILITIES

Where sub-metering of certain generator units is required, with the agreement of EirGrid, the Customer may supply metering class CTs and VTs for use on the sub-circuits. This equipment must comply with the standards set out in the CER meter code. Such equipment shall be subject to acceptance testing for each site.

The direction of exported active energy (MWh) as seen by the energy meter is determined by the polarity of the CT. Prior to installation of the sub-metering, the Customer is to provide EirGrid Metering with a full Single Line Diagram (SLD) of the site, which should clearly indicate the location of the meters and the ratios and polarities of all instrument transformers used. Depending on the polarity used, EirGrid Metering may require the CT tails to be reversed to ensure channel orientation consistency across all energy meters.

EirGrid's Meter Contractor is responsible for the provision and installation of the energy metering cabinet, the energy meters complete with modems and communication links to EirGrid Metering Department and all associated wiring within the metering cabinet with the exception of the CT and VT cabling external to the metering cabinet. **If there is a requirement to reverse the CT tails, the wiring reversal is to be done between the CT terminals and the Test terminals in the metering cabinet and is the responsibility of EirGrid's Meter Contractor.**

EirGrid's Meter Contractor are to seal all metering equipment, data collection equipment and associated modems and telephone links.

Termination of the external CT and VT cables to the terminations in the Energy Metering Cabinet is not the responsibility of EirGrid's Meter Contractor as it lies within the Station Electrical Contractors Scope of Work.

The Customer Commissioner is responsible for end to end testing of all required sub-metering signals from the CT/VTs to the metering cabinet terminals.

The Customer are to advise EirGrid's Meter Contractor and EirGrid Metering of the testing schedule to allow this end to end testing to be witnessed by EirGrid's Meter Contractor on behalf of EirGrid Metering.

EirGrid System Performance will issue the Energisation Instructions for the site.

12.2.2 ISSUING OF ENERGY METERING INJECTION TEST COMPLETION CERTIFICATE

EirGrid's Meter Contractor will only issue an Energy metering injection test certificate if the following criteria are met:

Where an interface kiosk is fitted between the Customer generator and the EirGrid metering cubicle and located within the boundary of the ESB Networks station, testing of the sub-metering from the kiosk to the metering cubicle shall first be performed by the station commissioner and witnessed by EirGrid's Meter Contractor Services.

The station

commissioner will then include the testing of the sub-metering cabling to the customers interface panel, as part of the main DOF. Where CT wiring reversal has been implemented in the metering cabinet, this is to be recorded by EirGrid's Meter Contractor in the energy metering DOF.

When this initial testing is complete it will then be the responsibility of the Customer commissioner to perform CT/VT injection tests from the generator/unit directly to the EirGrid metering cubicle. **These tests MUST be witnessed by EirGrid's Meter Contractor on behalf of EirGrid Metering.**

Where no interface kiosk is present, all sub-metering circuit injection tests will be performed by the Customer commissioner from the generator/unit directly to the EirGrid metering cubicle. **These tests MUST be witnessed by EirGrid's Meter Contractor on behalf of EirGrid Metering.**

The Customer commissioner will then issue a DOF for the sub metering CT/VT cabling detailing the tests from the generator to the metering cabinet terminals.

12.2.3 COMMISSIONING

The Telecom Commissioning Checklist will identify the links/shorting links on the VT/CT input into the Billing Metering Cabinet and ensure that these are left in the operational position following the full Billing Metering circuitry test.

The status of the sub-metering CT/VT input circuits excluding those within the Energy Metering Cabinet will be the responsibility of the Customer commissioner.

It is the responsibility of the Customer commissioner to advise EirGrid when the injection tests are to be performed on the sub-metering CT/VT input circuits, and to be signed and witnessed by an EirGrid meter representative.

The Customer Commissioner is to advise EirGrid if any seals need to be broken for further testing, after the issuing of the Energy metering injection test completion certificate, the Customer commissioner will take full responsibility for the sub-metering CT and VT circuitry excluding those within the Energy Metering Cabinet, until the plant is switched in.

12.3 PROVISION OF PULSES FROM COMMERCIAL ENERGY METERS

12.3.1 DOCUMENT SCOPE

Pulses from a single designated Check meter will be provided by EirGrid to parties who have such a requirement and have made a formal request to EirGrid for the service. This document defines:

- the energy (active and reactive) transfers for which pulses are provided;
- where the interface is located;
- the characteristic of the pulses; and
- The roles and responsibilities of the various parties.

12.3.2 ENERGY (ACTIVE AND REACTIVE) TRANSFERS

Pulses will be provided for the following:

- Active Energy - Exported (MWh)
- Active Energy - Imported (MWh)
- Reactive Energy – Export Lag (Mvarh) (Exported MWh, lagging Mvarh)
- Reactive Energy – Export Lead (Mvarh) (Exported MWh, leading Mvarh)
- Reactive Energy – Import Lag (Mvarh) (Imported MWh, lagging Mvarh)
- Reactive Energy – Import Lead (Mvarh) (Imported MWh, leading Mvarh)

12.3.3 INTERFACE

An interface will be provided by EirGrid by means of file terminals located within the Energy Metering Cabinet. The schematic drawing included as part of this document details the terminal and wiring layout for the interface. A detailed wiring diagram will be provided for each installation.

The energy meter output pulse cables to the interface must be multiple twisted pair cables with a CSA of 0.44 mm².

12.3.4 PULSE DEFINITION

12.3.4.1 LANDIS+GYR ZXQ TYPE METERS

Pulses will be provided according to the specifications detailed below.

Electrical Characteristics

Type	Solid state relay
Max switching voltage	125 V AC/DC
Min switching voltage	24 V DC
Max continuous switching current	55 mA AC/DC
Min switching current	0.1 mA
Contact resistance	</= to 50 ohms
Insulation between the contacts, and other current circuits	3.75 kV AC/1 min
Insulation between contacts groups	2 kV AC/1 min

Pulse Outputs

Pulse outputs are be provided via normally open potential free relay contacts.

Pulse Width

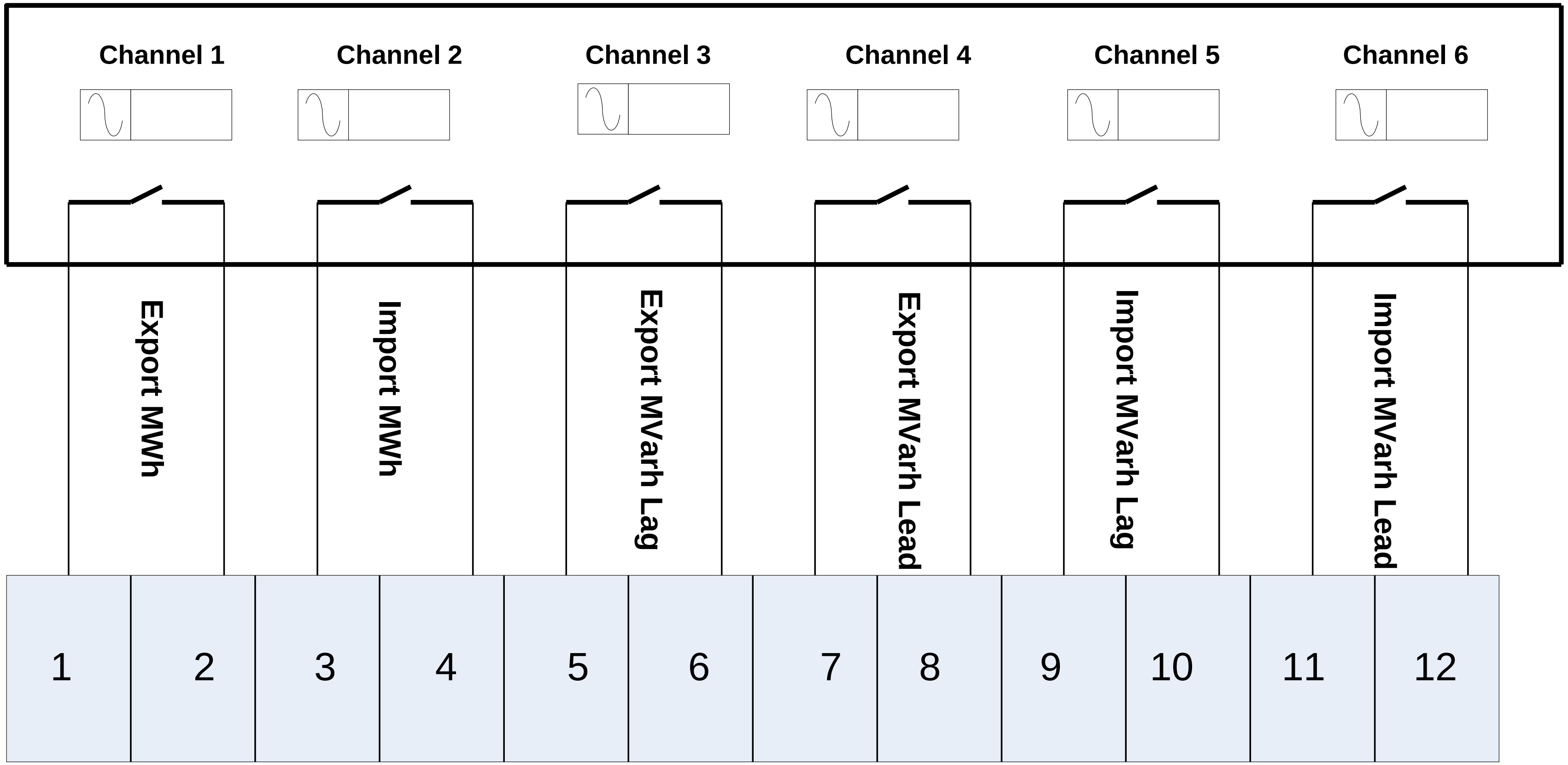
Pulse width	80 ms

12.3.5 ROLES AND RESPONSIBILITIES

EirGrid will be responsible for the provision of pulses at file terminals within the Energy Metering Cabinet according to the specification in this document. The provision of cabling, termination of cabling at the file terminals and commissioning of the pulse monitoring equipment is the responsibility of those requesting the service. During commission of a new connection it is the responsibility of those requesting the service to ensure the pulse monitoring equipment is in place in order to provide a full end to end test of the pulse outputs to the pulse monitoring equipment. If in the event that pulse monitoring equipment is not in place and requires a return visit after commissioning of the energy metering cabinet to perform a full end to end test this cost will be subject to the customer requesting the service.

Schematic Drawing of Meter Pulse Outputs to IPP

Meter Pulse Outputs



Cabinet Pulse File Terminals (IPP Interface)

APPENDIX 1: METERING TEST CERTIFICATES

ENERGY METER INJECTION TEST COMPLETION CERTIFICATE

As per EirGrid Energy Metering Commissioning and DOF Procedure requirement 12.1.5, the following injection tests have been performed by the Commissioner and witnessed by an EirGrid meter representative.

- Active Energy - Exported (MWh)
- Active Energy - Imported (MWh)
- Reactive Energy – Export Lag (Mvarh) (Exported MWh, lagging Mvarh)
- Reactive Energy – Export Lead (Mvarh) (Exported MWh, leading Mvarh)
- Reactive Energy – Import Lag (Mvarh) (Imported MWh, lagging Mvarh)
- Reactive Energy – Import Lead (Mvarh) (Imported MWh, leading Mvarh)

The above tests have been performed to determine the direction of flow of energy through the EirGrid billing meters only.
All CT links have been left in the operational position.
All VT fuses have been installed and tested.

Witnessed on behalf of EirGrid meter data Provider,

Date:

Signed: ____________________

EirGrid Meter Contractor
Signed copy to be returned to EirGrid metering.

ENERGY METER INJECTION TEST COMPLETION CERTIFICATE

(SUB METER)

As per EirGrid Energy Metering Commissioning Procedure for Sub-Metering Certification requirements section 12.2.2, the following injection tests have been performed by the Customer and witnessed by an EirGrid meter representative.

- Active Energy - Exported (MWh)
- Active Energy - Imported (MWh)
- Reactive Energy – Export Lag (Mvarh) (Exported MWh, lagging Mvarh)
- Reactive Energy – Export Lead (Mvarh) (Exported MWh, leading Mvarh)
- Reactive Energy – Import Lag (Mvarh) (Imported MWh, lagging Mvarh)
- Reactive Energy – Import Lead (Mvarh) (Imported MWh, leading Mvarh)

The above tests have been performed to determine the direction of flow of energy through the EirGrid billing meters only.
All CT links have been left in the operational position.
All VT fuses have been installed and tested.

Witnessed on behalf of EirGrid meter data Provider,

Date:

Signed: ____________________

EirGrid's Meter Contractor
Signed copy to be returned to EirGrid.

CHECK METER PULSE OUTPUT TEST CERTIFICATE

As per EirGrid Energy Metering Procedure for provision of pulse outputs the following tests have been performed by an EirGrid meter representative during commissioning.
It is the responsibility of those requesting the service to ensure the pulse monitoring equipment is in place to perform a full end to end test during commissioning. If in the event that pulse monitoring equipment is not in place, *the cost of a return visit will be subject to those requesting the service.*
The Check meter has been programmed with the following outputs

- Active Energy - Exported (MWh)
- Active Energy - Imported (MWh)
- Reactive Energy – Export Lag (Mvarh) (Exported MWh, lagging Mvarh)
- Reactive Energy – Export Lead (Mvarh) (Exported MWh, leading Mvarh)
- Reactive Energy – Import Lag (Mvarh) (Imported MWh, lagging Mvarh)
- Reactive Energy – Import Lead (Mvarh) (Imported MWh, leading Mvarh)

Pulse output Constants for meter number : ____________________
Active: ______________________ per impulse
Reactive: ______________________ per impulse
Pulse width: 80 ms
Frequency: ______________________ Hertz
Meter pulse output has been tested to: Meter Cabinet Terminals Yes / No
Customer Interface Yes / No
Customer pulse monitor equipment Yes / No
EirGrid Meter Contractor Signed: __________________
Customer Signed: __________________ Date ____________

EirGrid Meter Contractor return signed copy to EirGrid metering