

**Construction
Design Handbook**

**APPLICATION GUIDANCE NOTES FOR THE PROVISION OR
MODIFICATIONS OF A SUBSTATION CONTROL SYSTEM**

DH 20

Issue 2

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APPLICATION GUIDANCE NOTES FOR THE PROVISION OR MODIFICATIONS OF A SUBSTATION CONTROL SYSTEM

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1 PURPOSE

This design handbook has been compiled to offer guidance to suppliers when creating or modifying a Substation Control System and its associated database.

2 REFERENCES

TS 2.07	Specification for Substation Control Systems
TS 3.07.01	G174 Protocol Requirements of a Substation Control System (Archived)
TS 3.07.04	Substation Control System Operator Interface
TS 3.07.07	Synchronising and Voltage Selection (Archived)
TS 3.24.03	Substation Control and Facilities Common to all Bays
TS 3.24.04	Hardware Platform
TS 3.24.60	Synchronising
TGN(T) 94	Application of Electrical Measurement Transducers for Operational Metering Purposes.
TGN(T) 65	Preparation of G174Data for Substation Control Systems
TP127	Lifetime Management of Substation Control Systems.

300 Sheets – Paper or electronic (edi file) record specifying the GI74 database to be configured on the IEMS. These records detail the addressing structure used and the text fragments to be associated with the GI 'bits'. An alternative form of data presentation is being developed for use with IEC 870–5–101 using a structured Excel spreadsheet.

ADR – Alarm Data Rationalisation. ADR text fragments are those standard alarm texts used on the IEMS. These fragments are conveyed to ENCC via the 300 Sheets (GI74 does not itself transmit alpha data but simply transmits 'bit' status with which the 300 sheets then associate alarm legends, analogue ranges etc). These text fragments can be either the IEMS presentation of a single alarm generated on site or the IEMS presentation of a grouped alarm. With an IEC 870–5–101 database it is expected that ENCC will receive raw alarms for subsequent grouping on the IEMS.

AIS – Air Insulated Switchgear

ARS – Automatic Reactive Switching.

ATCC (AVC) – Automatic Tap Change Control (Automatic Voltage Control).

BAY – In the context of this Document, a bay consists of a discrete set of control equipment capable of controlling and monitoring the primary and secondary plant of one or more circuit or circuit ends.

BCU – Bay Control Unit

CANC – Cancel Control, (associated with CB synchronising).

CB – Circuit Breaker

CCT - Circuit

CDU – Construction Delivery Unit

Circuit – In the context of this Document, a circuit consists of one of the following circuit or circuit ends:

- Feeders, including: OHL, Transformer, Generator and Series Reactor.
- Bus Section (including Mesh Corners).
- Bus Coupler.
- Shunt Compensation Equipment.

DAR – Delayed Auto Reclose.

DBI – Don't Believe It (00 or 11 state for a double point indication).

DBU – That part of the IEMS system called EBU by all parties:

- **NB. Following a series of discussions it has been agreed that for the purpose of SCS I/O Schedules, GI74 databases, SCS HMI displays and IEMS displays the terms EMS and EBU will be used. These terms are used throughout the remainder of this document. In this context EMS is deemed to be synonymous with the ENCC term Main.**

- **Active System** – That part of the IEMS (EMS or EBU) that is currently 'In Control' of all outstations. Note: Only one system (EMS or EBU) is active at any time and that one system 'controls' all SCSs. It is not possible to have some SCSs under the control of the EMS system and other SCSs under the control of the EBU system.

- **Standby System** – That part of the IEMS (EMS or EBU) that is currently not 'In Control' (ie not Active) of all outstations but is scanning (receiving analogue and digital point changes) all outstations and is thus in synch with the Active system.

DDS Database Development Syatem, used for database additions and amendment on the iEMS system

DNO – Distribution Network Operator

DSS – Data Set Switch, this comprises a database change both on the site SCS and on the iEMS.

ENCC – Electricity National Control Centre, the location from which operational control of the Power System is performed by Network Operations.

EDI – Electronic Data Interchange file this is a comma delimited text file used for echanging 300 sheet data between systems

GEM – Generic Equipment Model. This is a spreadsheet showing alarms, alarm grouping, Indications, Controls and where appropriate analogues pertaining to a particular type and, where multiple functions can be provided, function of a plant item or item of equipment.

GI74 – The Master Station (IEMS) to Outstation communication protocol presently used by National Grid.

GIS – Gas Insulated Switchgear

GSP – Grid Supply Point

HMI – Human Machine Interface. This is generally a Screen with keyboard and mouse or rollerball.

HV – High Voltage.

IEC 870–5–101 – An alternative Master Station to Outstation communication protocol being considered by National Grid and which has been adopted on a small number of limited function outstations. The IEMS supports both GI74 and IEC 870–5–101 but unless otherwise agreed, GI74 will be used on all outstations. No SCS will be scanned using GI74 and IEC 870–5–101 simultaneously.

IED – Intelligent Electronic Device

IEMS – the Integrated Energy Management System comprising Main and DBU systems in addition to the DDS (Database Development System) and other components of no relevance to SCS .

IMUP – Information Management Unit Port.

IONA – Investment in On-Line Network Analysis.

LCP – Local Control Point

LV – Low Voltage.

Main – That part of the IEMS system called Main by ENCC but commonly called IEMS by parties outside ENCC.

MAL – Master Alarm List A general list of raw alarms with associated grouping and Remote Operating Point alarm legends. This list is no longer updated but it should be used for guidance whenever a Generic Equipment Model does not exist. Care should be exercised in the use of the Master Alarm List as some raw alarms appear in more than one group. The correct grouping can be determined only by consideration of the associated plant.

MOSC – Manual Override of Synchrocheck Control, (associated with CB synchronising).

MOSI – Manual Override of Synchrocheck Indication, (associated with CB synchronising).

MSC – Mechanically Switched Capacitor.

MVArso – Mega VARs sent out.

MWso – Mega Watts sent out.

NOC – Network Operations Centre, the location from which safe access to the transmission system is managed by Asset Management, in addition to the handling of Non-Trip 2 Alarms. Both ENCC and NOC access the same IEMS system but with different authority levels.

NMR - Nominal Maximum Reading, the analogue value associated with the nominal maximum GI74 value. This is 800 for high resolution and 100 for normal resolution analogues. This allows an over range of around 20% the maximum GI74 values that can be sent are 1023 and 127 for high resolution and normal resolution respectively.

NMV – Nominal Maximum Value this is the same as NMR above

NT1/NT2 Non Trip 1 or 2, alarms which do not come about as the result of a trip. These are categorised as type 1 or type 2 to determine the urgency of the actions required.

OMS – Operational Metering Summator, a summation device used to obtain metering data from Settlement Meters for Supergrid/LV Transformers and Generator circuits.

OTS – Operational Tripping Scheme, a scheme allowing the tripping generally of generation triggered by the tripping of circuit(s) monitored by the scheme.

PSSC – Power System Synchrocheck Control, (associated with CB synchronising).

PSSCI – Power System Split Control Indication, (associated with CB synchronising).

PSSI – Power System Split Indication, (associated with CB synchronising).

PTE – Portable Telecontrol Emulator. A software tool used by both National Grid and Suppliers to test the SCS GI74 database. The use of this common tool for independent testing carried out by the two parties (NG and supplier) ensures the quality/compatibility needed to permit the Master Station and SCS to be connected without the need for detailed 'end to end' testing.

QB – Quadrature Booster.

RCP – Remote Control Point. Operator Interface equipment installed at a remote location used to control a substation. May be sited at a ROP or ENCC.

RIP – Running, Incoming and Phase Angle Voltage analogue measurements, (associated with CB synchronising).

ROP – Remote Operating Point (where provided). A site containing the Remote Control Point for a substation under the direction of a control engineer at the ENCC.

RTU – The term sometimes used at ENCC instead of SCS. SCS is however the preferred term.

SBMCP – Substation Based Maintenance Control Point.

SCADA – Supervisory Control and Data Acquisition this term is often used to describe substation control systems

SCC – Synchrocheck Close Control, (associated with CB synchronising).

SCP – Substation Control Point. The central Operator Interface provided for control of the SCS within the substation.

SCS – Substation Control System. The collection of telemetry equipment, man machine interfaces and software which is the subject of TS 2.7.

SRSI – Synchrocheck Relay Selected Indication, (associated with CB synchronising).

SVC – Static VAr Compensator.

TCIP – Tap Change In Progress.

VOP – Virtual Operating Point

VSC – Voltage Selection Control, (associated with CB synchronising).

VSI – Voltage Selection Indication, (associated with CB synchronising).

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4 INTRODUCTION

National Grid operates a fully Tele-commanded (remote operation from the Electricity National Control Centre) power system, for which purpose Substation Control Systems are provided. SCSs are also provided to acquire data from embedded substations, not under the control of National Grid but from which data is needed to permit the safe, secure and efficient operation of the power system. This document supplements Technical Specifications and other documents where it is considered that more detailed guidance is required.

5 GENERAL REQUIREMENTS

The primary objective of a Substation Control System is to secure the control and operation of plant items to facilitate the efficient running of the Supergrid Transmission System. To meet these objectives it is necessary that the SCS provides the required functionality and is configured at each substation to provide the control facilities and information required to effectively operate the Substation Plant.

The SCS functionality is defined in TS 2.7 and documents referred to therein. The configuration of the SCS is the subject of this document. The guidance previously contained in TPS 2.7.1 has been incorporated into this document and tables showing the requirements of various items of plant and equipment are contained in appendices 2 to 4.

The tables in appendices 2 to 4 provide application policy for the majority of plant items, circuit configurations and substation topologies which are present on the National Grid Transmission System and set out the control facilities and information to be provided at each control point and to other Users including those external to National Grid at Interface substations..

Throughout the document, reference is made to the facilities to be provided at the Electricity National Control Centre (ENCC). Some facilities/data will however be distributed from ENCC to the Network Operations Centre (NOC). It is not the purpose of this document to define the distribution of these facilities; they will be managed by National Grid - Network Operations in conjunction with Asset Management.

National Grid requirements for 'plant information' are also specified in the form of data to be presented at an Information Management Unit Port. Where these data requirements require additional inputs to the SCS and the source does not currently exist, the inputs shall be physically provided and configured on the SCS to allow future connection as and when the source plant inputs become available.

6 PLANT ITEMS

Appendix 2 provides guidance on the control, indications, alarms, and where appropriate analogues, which are to be provided for the following primary and secondary plant items:

Circuit Breakers

Disconnectors

Earth Switches

Shunt Compensation Equipment (MSCs, Reactors)

Transformers

Quadrature Booster Schemes

ATCC Schemes

ARS Schemes

SVCs

DAR

Feeder Protection

Busbar Protection

Other Protection

Protection Signalling Systems

Intertripping

Miscellaneous Systems

7 CIRCUITS

Additional facilities for circuit configurations not covered in Appendix 2 are detailed in Appendix 3, Tables A3.1 to A3.2.

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8 SUBSTATION

Appendix 4 gives guidance on miscellaneous facilities which are to be provided for each site and substation voltage level. The provision of facilities includes:

Additional site alarms.

Voltage level based Site analogues.

9 ALARM AND EVENT LOGGING LEGENDS

Reference is made throughout the appendices to the source and group alarm requirements of plant items, circuits and substations. This hierarchical approach should ensure that the majority of the alarms which are required to be presented at the various control points and user interfaces are identified. There will, however, be a number of instances where equipment and alarm information is available which is not identified using this approach.

To ensure consistent alarm information is provided at all control points, reference should be made to the National Grid Master Alarm List. This list provides guidance on the use of alarm texts, event logging legends, alarm grouping and alarm filtering requirements for most older items of plant and equipment. The MAL is no longer updated and Generic Equipment Models should be available for items not covered.

More modern items of equipment and plant are covered by the use of GEMs. These provide a comprehensive list of alarms alarm grouping information controls, indications and where appropriate analogues for the item.

10 PLANT INDICATIONS

Unless specified otherwise, all digital plant indications shall be provided as single points with the OUT/OPEN condition = 1 status.

11 RESPONSIBILITIES

11.1 Construction Delivery Unit (CDU) & Suppliers

It is the CDU/supplier's responsibility to provide a configured and tested Substation Control System compliant with National Grid's technical specifications and meeting user requirements. This document is intended to provide guidance on the implementation and application of these specifications and requirements.

For the purpose of this document the term supplier is deemed to include any CDU (including Overhead Line CDU) carrying out work on behalf of National Grid.

11.2 National Grid

It is National Grid's responsibility to ensure the supplier is aware of all the relevant technical standards and requirements.

12 SCS NAMING AND ADDRESSING

Each SCS (RTU) will be assigned a Site Name, Short Code and GI74 Station Address for use in SCS database configuration and that will appear in the edi file (300 Sheets).

12.1 SCS Naming Convention

Where there is a single SCS on site (controlling either a single or multiple voltage levels) the Site Name will simply be the name of the substation as above and the short code will not contain any voltage reference. For example:

Site name ALDWARKE (ALDW); Address: 35

Where there are multiple SCSs on site, each controlling different voltage levels each site name will include the highest voltage level controlled by that SCS or alternatively an extended name representing the substation being controlled. Where there are two SCS systems on the site with the same voltage level, for example where a new GIS site with a new SCS is built to replace an existing AIS site the site name will include a suffix to distinguish between the two e.g Mannington A and Mannington B. The associated short code will include a number referencing the highest voltage or alternatively a character representing the nature of the site (eg R for Rail site or A for SCS A and B for SCS B etc.)

E.g. at Harker there are three SCSs, one controlling the 400kV substation, one controlling the 275kV and 132kV substations and one controlling the Network Rail substation. Thus we have:

- Site name Harker 400kV (HARK4) Address: 42
- Site name Harker 275kV (HARK2) Address: 32
- Site name Harker 400kV/25kV (HARK-R) Address: 42

In the third example above, dual voltages are included in the site name as the highest voltage (400kV) is already in use. Note that coincidentally the first and third examples have the same address – this is acceptable. Site names and short codes are controlled and assigned by National Grid and it essential that names and short codes are not duplicated.

Whilst this document is not currently intended to cover off-shore transmission many of the requirements for National Grid SCSs are equally applicable to this new environment. Any parties involved in the preparation of windfarm SCS GI74 databases should obtain the agreed names, short codes and station addresses from National Grid before a new database is built in order to avoid unnecessary re-work.

Where windfarms comprise multiple off-shore platforms, additional agreement should be reached on the manner in which the off-shore platforms are named and described in databases - the proposal is to use alpha characters to describe the sub-platform (eg London Array Off-Shore Wind Platform A for which the short code would then be LOAW where the first two characters describe the development, the third is the platform and W is 'water' indicating the off-shore nature of the location).

12.2 RTU Address and Block Sizes

Site names and short codes can be found in the PTE Site Codes csv file. In the case of a new site, for which no name/code is available, guidance should be sought from the National Grid Database Coordinator. The Database Coordinator will also advise on the outstation address – this address determines the number of data blocks available for the SCS database. Suppliers should therefore consider the database size when requesting an address.

- Address Range 1-31 - 8 blocks
- Address Range 32-63 - 4 blocks
- Address Range 64-127 - 2 blocks
- Address Range 128-255 - 1 block

In order to determine the number of blocks required for an SCS, an accurate estimation of the maximum number of Control, Indication, Alarm and Analogue points is required.

As a guide to this if the standard function allocations, as described in TGN(T) 065 and subsequent amendments in function allocation conventions are used, the number of points available per block is as follows:-

- Single Controls – 2 function allocations – 256 points
- Double Points – 2 function allocations – 112 points
- Single Points – 2 function allocations – 224 points
- High Resolution Analogues – 5 function allocations – 35 analogues

These function allocations **can be amended if required** to accommodate an unusually large number of any particular data type. e.g. - the functions previously reserved for data types no longer used such as Printometers or Telegraph could, if required, be used for High Resolution analogues. It is not permissible however to have more than one data type in a function. Each function should therefore have the same data type across all blocks.

13 SYSTEM ARCHITECTURE

System architecture will largely be determined by the suppliers but National Grid expects that there will be a Bay Controller (Unit) per circuit where a circuit comprises:

- Feeder Circuit (whether Double Busbar or Mesh connected))
- Main Bus Section
- Reserve Bus Section (for an AIS installation where the reserve Bus Section comprises just a single or two disconnectors it may be acceptable to include these items in the corresponding Main Bus Section Bay Controller).
- Bus Couplers
- MSC
- Shunt Reactor
- Series Reactor (two Bay Controllers where the two ends are at the same substation)
- SGT HV (whether Double Busbar or Mesh connected)
- SGT LV (dependant upon the site layout it may be acceptable to combine the HV and LV into one Bay Controller)
- SVC
- Mesh Corner
- Common Bay – typically, indications required from non-National Grid assets would be acquired via the Common Bay where there is no circuit specific bay provided. Alarms from other 'common equipment' (eg common batteries, air systems etc) would also be acquired via the Common Bay. Other substation level systems (eg Operational Tripping, Auto Close schemes etc), should be associated with the Common Bay although it is accepted that in some cases the size of the substation level system may dictate that a dedicated bay control unit is provided.

The above list is not exhaustive but should provide sufficient guidance with respect to the principles to be adopted. Where additional guidance is required, National Grid's Design Assurance should be consulted.

The requirements above are intended to ensure that required level of Site Based Maintenance selectivity is achieved where the selection of this function is hardware based. It is not permissible for Bay Controllers to interface with two or more equipments/circuits where this would prejudice the effective use of SBMC. See Site Based Maintenance Control section.

14 DATABASE CONFIGURATION

SCS databases should provide the facilities (controls, indications, analogues and alarms) specified in this document. The detailed requirements for each plant item (e.g. circuit breaker, protection) are specified in Generic Equipment Models (GEMs), following the principles set out in the Master Alarm List (MAL). Where no GEM exists for a particular plant item the party requiring the GEM should produce a draft and seek approval as detailed in TP 127. ADR text fragments used within an SCS database and associated edi file should be obtained from the standard list maintained by Network Operations. Where no text fragment exists, agreement must be sought from NO to the use of a new fragment. This will then be incorporated into the standard list, which will be updated and issued as Appendix 1 of this document.

14.1 Synchronising

With the exception of most transformer HV circuit breakers and shunt connected plant, all National Grid circuit breakers employed on the HV Transmission system shall be equipped with synchronising facilities.

14.2 Additional Indications

Earth Switch indications are required on SCS HMI displays. They are not generally required at ENCC. There are however exceptions to this.

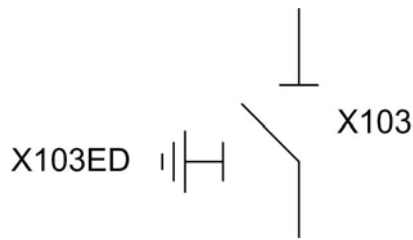
The first example of this is where an earth switch is associated with an (F4) ferroresonance quenching scheme. In this case the earth switch indication should be configured in the SCS GI74 database and returned to ENCC.

In addition to the earth switch indication requirements for an F4 scheme, an earth switch OPEN control is also required, as is a Ferroresonance Quench IN control and associated self re-setting indication.

The other example is in the case of three position switches. The Safety Rules Third Edition Guidance document R3.2 (b) states, with reference to Gas insulated switchgear three position switches, "in order to operate this equipment as designed the disconnector can be opened and selected to earth position by the Control Person (Operation) via telecommand"

In order to accommodate this, an exception to the rule shall be made in the case of three position switches. Remote control and indication of these switches shall be included in the SCS GI74 database.

A diagrammatic example of a three position switch is shown below.



14.3 Description Field

The description field used within SCS databases, for the purpose of outputting to event/alarm lists on site, shall provide meaningful information to the engineer receiving those alarms and should ideally align with alarm legends on drawings. Where this is not possible (e.g. due to limited text fields) alarm legends should be unambiguous.

14.4 Alarms Source Identification

Ideally all alarms should be logged and reported (locally and at ENCC) by the SCS on the site at which the alarm is initiated. Where this is not practical (e.g. cable oil alarms from remote compounds or in rare circumstances operational tripping scheme alarms) care should be taken to ensure that the (geographic) source of the alarm is clearly identified. The complete alarm annunciation should always lead the responding engineer to the right location as expeditiously as possible. Site codes are available for tunnels and Cable Sealing End Compounds where these are at locations remote from a substation.

14.5 Control and Indication Nomenclature

Where controls and associated indications are configured in an SCS database the control and indication description used in the edi file must be identical.

E.g. where target voltage selections and associated indications exist these should be configured as follows:

Control	Description	Status	
	Target 132kV	IN	
	Description	Status	
		Alarm	No-Alarm
Indication	Target 132kV	IN	OUT

This requirement is a function of the IEMS whereby a single record is created (single description field) with all the control and indication attributes in that single record.

14.6 Status Pairs

Events received by the IEMS are configured as Trip events, sequence events, non-trip 1 (NT1) and non-trip 2 (NT2) events (alarms). Trip, sequence and NT1 alarms are used for the immediate management of the power system and are available to operational staff at ENCC. NT2 alarms (requiring less urgent attention) are made available to Response Staff at the NOC.

NT2 alarms are generally identifiable by the inclusion of the term ABNORM or ABNORMAL in the ADR text in the edi file. More particularly they are characterised by the use of the

status pair ON/OFF. A small number of exceptions exist within the Master Alarm List and some GEMs. For example:

- ON MTCE ON/OFF
- ON LOCAL ON/OFF
- ON AUTO ON/OFF.

Automatic IEMS configuration is much improved if the ON/OFF status pair is limited to NT2 alarms. Therefore it is required that ON MTCE etc is configured with status pair IN/OUT.

14.7 Substation/Voltage vs. Cct Names

The correct nomenclature for SCADA stations and circuits is defined in NGUK/NO/BP1406 and TP109 respectively. Care should be taken to ensure that a substation name/voltage cannot be confused with a circuit and associated number. This shall be achieved by the correct use of spaces. E.g.

Thorpe Marsh 275kV substation shall be THOM2 (no space) whereas the Thorpe Marsh number 2 circuit at West Melton shall be THOM 2 (space).

15 ANALOGUE REQUIREMENTS

15.1 Metering

Operational metering is that data (analogues) supplied to ENCC via SCSs for operational management of the transmission system. These analogues (eg feeder MW, MVar, kVolts) are generally supplied via transducers or direct ac input. Analogues at Grid Entry points, (generator connection), or Grid Supply Points (supplies to DNOs via National Grid Supergrid Transformers) however, are supplied to the SCS via an Operational Metering Summator (OMS). The Operational Metering Summator receives its data (pulses) from Settlement Meters, and is thus deemed to be of high accuracy.

Care should be taken when providing analogues at Grid Entry or Supply Points, and in these cases reference must be made to the Technical Appendices of the Bilateral Connection Agreement.

15.2 Additional Analogue Requirements

The circuit/plant specific analogue requirements to be provided by an SCS are given in the appendices and TGN(T)94 (analogue ranges). Whilst the appendices cover most analogue types, a number of additional analogues may be required (eg SGT Conservator Oil Level, ambient temperature, wind speed) not yet formally documented. Where there is any doubt about the requirements advice must be sought from National Grid Design Assurance.

15.3 Frequency

Frequency shall be provided as per TGN(T) 94. Frequency analogues should be provided for all generating sites and for other sites as specified by National Grid (Network Operations). Reference should therefore always be made to Design Assurance who will liaise with Network Operations to confirm frequency requirements. Frequency reading should be derived from the automatic selection scheme for each voltage level within the substation. Where the substation is to be run permanently split, two frequency readings should be provided from the automatic selection schemes, one on each side of the split.

15.4 Range Requirements and Sign Convention

TGN(T)94 specifies the analogue range requirements for specific circuit configurations/plant sizes etc but is based on transducer technology. Increasingly, analogues are being provided

by direct ac input but the range requirements are the same as for transducer sourced analogues. Work is ongoing to update/rationalise these documents.

It is intended to standardise NMR requirements for 400kV and 275kV circuits as follows:

- 400kV Feeder - 4000MW/2000MVar
- 275kV Feeder – 2000MW/1000MVar

This should be readily achievable when direct ac inputs are used but may not be when transducers are used – transducer current capability must be considered.

The adoption of these standards should avoid the need in future to modify SCS NMRs when circuit thermal ratings are enhanced

Analogue sense (signing +ve or –ve) is of critical importance to ENCC; extreme care must therefore be taken when configuring analogues. Guidance on this issue is provided in TS 3.24.4, and TGN(E)94 Issue 2 (errors exist in these documents, but will be corrected). Analogue sense output on SCS HMIs should align with the sense provided to ENCC to ensure that there is no confusion caused when comparing analogue values at the two locations. It is accepted that there may be occasions when tabular displays on site using this convention appear to contradict Kirchoff's current rule (ie when SGT LV analogues are displayed on HV analogue tables but with the sign convention appertaining to the LV).

Where it is required to assign directional flow to a quantity (eg MW and MVar], a "positive"(+) sign shall indicate "Export" and a "negative" (-) sign "Import". "Export" is defined as a flow away from the measuring point and "import" flow toward the measuring point. The sign convention shall apply to both remote and substation control points. Figure 1 details the application of this sign convention for most types of feeder, transformer, shunt connected plant and generator connections.

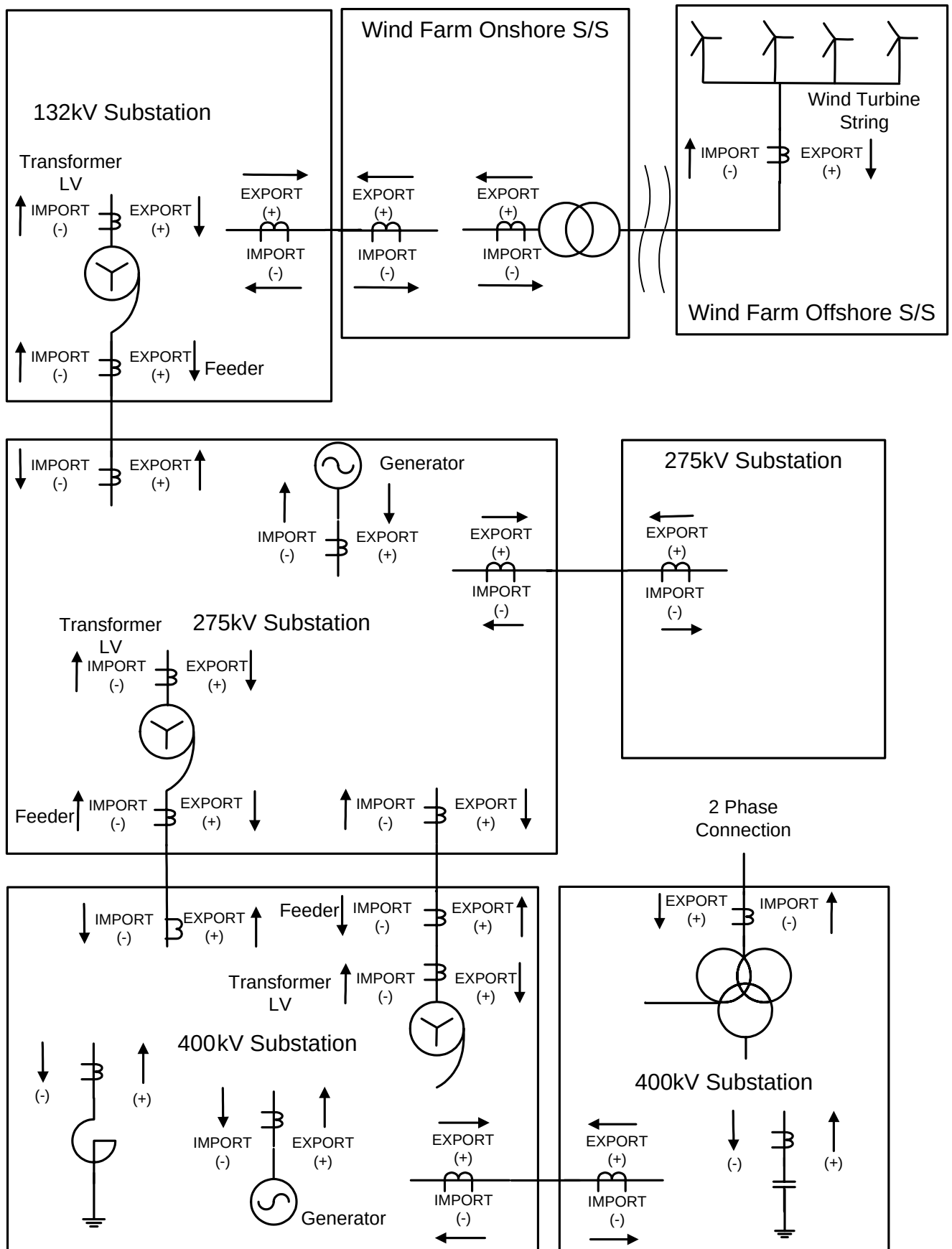


Figure 1 Analogue Sign Conventions

16 SITE BASED MAINTENANCE

The SCS shall permit selected plant/circuits, on a circuit by circuit basis, to be transferred to and from Site Based Maintenance Control (SBMC) mode. This action shall be subject to the operator authorisation levels appropriate to controls. Any change in the operational point of control of the substation (e.g. from RCP to SCP) shall not result in any change of point of control for those circuits which are in Site Based Maintenance Control mode. All data acquisition for the circuits selected to Site Based Maintenance Control mode shall continue to be archived and annunciated at the Substation Control Point. However, indications and alarms on these circuits, which are normally reported to the Remote Control Point shall be suppressed (automatically if part of SCS configuration) or be able to be suppressed,

16.1 Implementing SBMC

The above requirement should be implemented as follows:

- a) The selection of plant to SBMC shall be made only by an operator on site with the appropriate level of authorisation.
- b) Plant under SBMC shall be operable from the SCP but not from ENCC (remote)
- c) Status changes of plant (both primary and secondary – see exceptions below) under SBMC shall not be reported to ENCC but shall continue to be archived and annunciated at the SCP.
- d) SBMC shall be available on a plant/circuit basis not simply on a hardware (bay controller) basis. This ensures that where plant/circuits share a bay controller (eg a Mesh corner bay unit containing both mesh corner and associated Bus Section Circuit Breaker I/O) SBMC can be made selectively to reflect the various combinations of plant outage/fault). Logical assignment of the SBMC function is therefore required and may result in multiple SBMC controls being associated with a single Bay Controller).
- e) A list of points currently subject to SBMC shall be available to the site operator

The Site Based Maintenance (SBMC) function is used during maintenance (or fault repair) outages of equipment to avoid sending unnecessary (nuisance) alarm and indications to ENCC from out of service plant whilst maintaining full SCP functionality for testing purposes. Point suppression (on an individual point basis) should ideally be achieved by database configuration and a single (per plant/circuit) SBMC suppression control on the HMI.

If automatic point suppression cannot be achieved by database configuration and SBMC selection then the SBMC selection shall make available to the operator a list of points (assigned logically) so that he can readily suppress (and afterwards unsuppress) all required points.

16.2 Alarms NOT to be Suppressed

Certain categories of alarm must not be suppressed at any time so these alarms must not be included in the suppression 'configuration'.

Alarm categories that must not be suppressed are:

- a) Gas density alarms from GIS Substations.
- b) Cable oil pressure alarms
- c) Environmental alarms.

- d) Alarms input to one bay control unit, but which are derived from/associated with another bay control unit. E.g. if an alarm associated with or derived from BCU A (e.g. watchdog alarm) is input to BCU B, the selection of SBMC for BCU B shall not result in suppression of the alarm associated with BCU A. Logical (rather than hardware assignment of SBMC alarm suppression is required.

16.3 SBMC and Alarm Grouping

Suppression of points associated with group alarms shall not prevent the normal operation of those group alarms from all non-suppressed group members.

Further information can be obtained from TS 2.7 and TS 3.7.33 (Archived).

17 HMI DISPLAYS

The requirements to be met by SCS HMIs are given in TS 3.7.4. In general displays provided should include a substation overview (split if the size of the substation is such that it cannot be displayed adequately on a single screen) and a series of detailed circuit displays. These circuit displays should include displays for ATCC, ARS, Auto Close, OTS etc. The substation overview may include earth switches if the inclusion of these would not render the display unclear.

Where individual circuit displays include reference to the adjacent circuit/plant, consistent naming should be employed at these 'boundaries'. Circuit/plant names used on displays should be either the full name (as shown on the Operation Diagram) or the abbreviated circuit name based on the standard 4 character codes. Where circuit numbers exist (e.g. Circuit 1, Circuit 2) to distinguish between circuits, the number must be preceded by a space.

17.1 Requirements for Specific Systems

Where there are specific requirements (e.g. status displays for numeric busbar protection systems where there are duplicated master units – only one in service at any one time) specific displays (example below) should be developed for use on the substation overview display or circuit display(s) as appropriate).

Site Busbar protection	
SYSTEM 1	IN (or OUT as appropriate)
SYSTEM 2	OUT (or IN as appropriate)

And on the circuit displays we add

Busbar Protection Field Unit	
On Maintenance	IN (or OUT as appropriate)
On Test	IN (or OUT as appropriate)

In the event of a Busbar Protection System (Master Unit) becoming faulty, it is essential that ENCC staff understand which of the two systems is faulty. Therefore discrete BB Prot System 1 and BB Prot System 2 faulty alarms are required.

18 ALARM MANAGEMENT

Management and annunciation of alarms is crucial for the successful operation of the power system. For most alarms the way in which they are fully described (originating substation/voltage, plant item, alarm description, status) is straightforward. For some systems however, care should be taken to ensure that all controls, indications and alarms can be readily identified with that system and location.