Eskom	Standard	Technology

Title: **SUBSTATION CONTROL SYSTEM COMISSIONING**

Unique Identifier: **240-106271076**

Alternative Reference Number: **41-517**

Area of Applicability: **Engineering**

Next Review Date: **STABILISED**

COE Acceptance	**DBOUS Acceptance**
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Date: 20 July 2021	Date:

This document is **STABILISED.** The technical content in this document is not expected to change because the document covers: *(Tick applicable motivation)*

1	A specific plant, project or solution	
2	A mature and stable technical area/technology	✓
3	Established and accepted practices.	

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Content

1. Introduction

Substation Control commissioning to the Eskom Control Centre/s involves the testing of signals between the Eskom Master Stations and substations to ensure that all signals are configures and operate as intended. This standard is intended to provide guidance to the commissioning teams on the procedure to be followed in commissioning of substation control systems.

2. Supporting clauses

2.1 Scope

This procedure covers all aspects of Transmission Control Systems commissioning in terms of specifying what checks and tests are required to be carried out and what information is necessary for Commissioning (Data Base compilation). Telecontrol systems shall include Enhanced Remote Terminal Units (ERTU's), Station/ITM RTU's and Bay processors. Local control systems shall include Local Alarm Panels, Human Machine Interfaces (HMI's) and Mimic Panels.

2.1.1 Purpose

This document establishes guidelines to be followed when commissioning Substation Control Systems (SCS) Equipment at Transmission Substations.

2.1.2 Applicability

This document shall apply throughout Eskom Transmission Division.

2.2 Normative/informative references

Parties using this document shall apply the most recent edition of the documents listed in the following paragraphs.

2.2.1 Normative

[1] ISO 9001, Quality Management Systems.

[2] 240-64100247 - Standard for Earthing of Secondary Plant in Substations

2.2.2 Informative

[3] E.M.S. Telecontrol requirements OPS 5026 Revision 1.

[4] ERTU and Bay Processor Installation, Configuration and Maintenance Manuals.

[5] Bay Processor Standard Data sheets

2.3 Definitions

2.3.1 General

Definition	Description
Substation Control System	Describes all the functionality contained in Telecontrol as well as local control systems.

2.3.2 Disclosure classification

Controlled disclosure: controlled disclosure to external parties (either enforced by law, or discretionary).

2.4 Abbreviations

Abbreviation	Description
BP	Bay Processor
CC	Control Centres
CT	Current Transformer
EA	Engineering Assistant
ERTU	Enhanced Remote Terminal Unit
HMI	Human Machine Interface
IDF	Intermediate Distribution Frame
IRB	Interposing Relay Board
IRC	Krone type Interposing Relay card
IRP	Interposing Relay Panel
LCP	Local Control Panel
PSU	Power Supply Unit
PTM&C	Protection, Telecommunications, Metering and Control
RTU	Remote Terminal Unit
SCS	Substation Control System
VT	Voltage Transformer

2.5 Roles and responsibilities

All Transmission Secondary Plant managers shall ensure that this standard is applied in all Transmission commissioning affecting control equipment.

All secondary plant managers shall ensure that the requirements of this standard are complied with.

Where Transmission and Distribution share a Substation Control System (SCS) in a Transmission substation, any changes to the SCS shall be completed in accordance with the respective Transmission standards.

2.6 Process for monitoring

Not applicable.

2.7 Related/supporting documents

Not applicable.

3. Commissioning of Substation Control Systems (SCS)

3.1 Requirements

1) Commissioning of the SCS shall be performed according to a pre-determine commissioning program.

2) All operable plant shall be operated from the responsible Control Centre(s).

3) Complete end to end testing of all telemetered data is required. Live testing is to be performed at all times unless it is impossible to do so at which time end to end implies testing from the furthest possible point.

4) If a tag block type IDF is used, all jumper points shall be soldered.

5) MegaWatt and MegaVar direction of flow shall comply with Eskom Standard OPS 5010/22/5.

6) All alarm grouping shall be software based.

7) Hardwired commoning of alarms will not be accepted.

8) A commissioning report outlining all outstanding work shall be completed by Control Field Staff within two (2) weeks of commissioning and copies shall be forwarded to National Control Systems Support, PTM&C Engineering Applications and the Project manager assigned.

   a) A copy of this report shall be stored in the relevant substation directory on the LAN S drive under the following directory:

   Spinnis01\Data_051\Subs\"Substation Name" OR

   b) any configuration management system in operation at the time.

9) Updated Excel databases (including IDF jumpering info), Derived data programs and Unicorn sub files shall be stored in either Spnnis01\Data_051\Subs OR any configuration management system in operation at the time.

10) All IDF drawings indicating "as built "status shall be forwarded to Control Applications for updating.

11) The handover document MC 403 shall be completed within two (2) weeks of commissioning and copies forwarded to all parties indicated in the document.

12) All SCS equipment installed at the substation shall adhere to the Standard for Earthing of Secondary Plant in Substations [2].

3.2 Prerequisites

1) Only personnel whom are deemed to be competent to work on substation control systems are permitted to commission substation control systems. In this regard the decision on competence shall be made by the relevant Transmission Secondary Plant manager.

2) HMI commissioning shall only be undertaken by personnel competent to configure and commission the HMI. Where work is undertaken by contractors, field staff shall be responsible for ensuring that the contractor commissions according to the correct procedures.

3) The SCS database (including all pseudo variable and tag names) shall be submitted to the relevant control centres at least four (2) weeks prior to commissioning date.

3.3 Commissioning Plan

1) A commissioning plan is necessary to ensure the successful commissioning of the SCS. This plan shall be compiled by Transmission Secondary Plant Grid personnel in conjunction with the outage schedulers, affected customers and any other stakeholders involved.

2) The final plan shall be distributed to all stakeholders prior to commissioning. These parties include but are not limited to:

   a) Control Centre(s) Managers

   b) Engineering Assistants (EA)

   c) Protection, Metering/Measurement and Control field teams involved in the project

   d) Project Manager

3) The plan shall include the program for commissioning each bay at the substation as well as the commissioning of all other substation device data (Buszone, Carriers, and Chargers etc.). It must state the time allocated per bay. It shall include any specific operating procedures that may be required for commissioning.

4) The commissioning plan must provide for the testing of all operable devices at each bay while also allowing for testing the alarms and indications from the protection schemes.

5) If the commissioning of the SCS will in any way affect Automatic Generation Control (AGC), provision shall be made in the commissioning plan to inform the relevant department as to the date on which the system will be returned to full operation.

3.4 Pre-Commissioning RTU Checks

1) Power Supplies (RTUs and BPs):

   a) Check RTU Power Supply Unit (PSU).

   b) If Chopover units are installed, check for correct operation.

2) All RTUs and BPs:

   a) Ensure that all devices have the latest official released firmware version (version number may be requested from the PTM&C Control and Automation Technology and Support department).

3.5 Commissioning Procedure

1) All bays at the substation shall be set to **Off Supervisory** for the duration of the commissioning and when any work on the IDF/MDF(s) is performed. This ensures that no inadvertent plant operations occur.

2) Commissioning staff shall verify with National Control Systems Support or National Control that the relevant alarm indicating that the panel is **OFF Supervisory** is active on Encor.

3) Notify National Control that spurious **Quality of Supply** alarms may be generated during testing which should be ignored until notified that testing has been completed.

4) If the commissioning of an SCS involves the change from one system to another (e.g. ERTU to D400), the cut-over shall be undertaken in a phased manner. This involves the retention of the ERTU data-base with the simultaneous activation of the D400 database on Temse and the per bay cut-over from the ERTU to the D400. On completion of the days commissioning as outlined in the commissioning plan, all panels in service are to be returned to **ON Supervisory** by the EA as per operating procedures.

5) Commissioning staff shall check with National Control Systems Support or National Control that all alarms at the substation are clear before leaving site.

6) Once all bays are **OFF Supervisory,** the IDF jumpers pertaining to the panels indicated in the commissioning plan shall be removed from the old SCS and re-jumpered to the new SCS as indicated in the jumpering schedule. Once this jumpering is complete, local testing shall begin.

7) The status of the actual plant versus the indications on the RTU(s) must be verified. Protection Field staff shall verify these indications and simulate the indications (if closed, simulate open and vice versa) from the furthest possible point. The furthest possible point is deemed to be from the Junction Box in the case of "**Phase 1**" protection schemes and from the Protection Panel in "**Phase 2-6**" Protection schemes.

8) All alarms shall be tested in a similar manner. Successful local testing of each digital point shall be indicated in the space provided in the database sheet.

9) All Controls shall be locally tested to the VAWA or similar relay. If the protection scheme does not provide for a visible relay or it cannot be determined by local testing that the control will be successful (e.g. Lock out Reset control), the relevant control shall be executed from the RTU and the protection field staff shall confirm that the control signal from the RTU is present at the correct contact in the protection scheme. Successful local testing of each secure control point will be indicated in the space provided in the database sheet.

10) All analogues points shall be locally tested as follows:

a) Wherever possible or if an analogue reading is suspected to be incorrect, Metering and Measurement staff shall measure the input to each transducer and confirm that the output of the transducer is in accordance with the input.

b) It shall then be verify that the panel meter reading is in accordance with the transducer output. The output of each transducer (mA) is to be compared with the analogue raw data value indicated in the RTU to confirm that the A/D conversion is correct. (10mA=binary count 4095).

c) Successful local testing of each analogue point shall be indicated in the space provided in the database sheet.

11) Field staff shall ensure that the busbar kV readings correspond on Temse. If not, the procedure outlined in the bullet above shall be followed.

12) Elements of all pseudo variables shall be initiated from the furthest possible point to ensure that the pseudo point is activated. In the case of earthlink indications, protection field staff shall initiate this indication from the furthest possible point. Successful local testing of each pseudo variable point shall be indicated in the space provided in the database sheet.

13) Once all bays have been testes, all remaining station alarms shall be tested to the Control Centres. These include BusZone, DC, carrier, security alarms and any other station alarms available at the station.

14) If provision has been made for live testing of plant, the following procedure shall be adhered to:

a) The bay shall be removed from service (if not already done so), by disconnecting from the power grid as per operating procedures.

b) The controls are then tested remotely by first placing the relevant panel ON Supervisory.

c) Once all the controls have been tested to be correct with the controller at the relevant Control Centre, all alarms and indications pertaining to that bay and NOT proven by operating a control, will be tested by the Control Centre.

d) All pseudo variables are to activated and tested to the Control Centres. All analogues shall be verified to ensure that the reading at the Control Centre corresponds with that at the relevant panel meter.

e) Once this is complete, the bay shall be returned to service and the panel shall be taken OFF Supervisory.

15) If live testing is not possible, the testing procedure that shall be followed is similar to that of live testing except the panel must remain OFF Supervisory and the controls shall be remotely tested from the Control Centres to the VAWA or similar relay and verified as per local testing.

16) Once all bays have been tested and returned to service, all remaining alarms shall be tested to the Control Centres. **Alarms shall be initiated from the furthest possible point**.

17) When testing to the Control Centres, control staff shall tick off each point successfully tested on the commissioning tick sheets and field staff to indicate the same on the space provided in the database.

18) When commissioning a protection scheme Bay Processor, a similar procedure as outlined above shall be followed. The Local Control Panel (LCP) shall be tested as per the tick sheets available from control Applications. The LCP analogues shall be verifies to be configures using the correct CT and VT ratios and that the reading displayed on the LCP is accurate according to the transducer outputs. These tests shall be completed in conjunction with Metering and Measurements field staff.

19) For operational purposes an HMI is deemed to be the control Centre and the commissioning procedure to be followed shall be the same as to a Control Centre.

4. Authorization

This document has been seen and accepted by:

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5. Revisions

Date	Rev	Compiler	Remarks
May 2016	1	Michelle Govender	Template change and new document number.
March 2007	0	Quinton Labuschagne	Original Document TPC41-517

6. Development team

The following people were involved in the development of this document:

- Michelle Govender
- Quinton Labuschagne

7. Acknowledgements

Not applicable.