Eskom	Standard	Technology

Title: **STANDARD FOR THE COMMISSIONING OF METERING INSTALLATIONS (HV AND MV)**

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Content

Figures

Tables

1. Introduction

The commissioning procedure for a metering installation entails functional and accuracy testing of the following components of the metering systems:

a) Primary plant equipment associated with the metering installation such as Current Transformers (CTs), Voltage Transformers (VTs) and their associated cabling.

b) Secondary plant equipment such as meters, recorders and communications equipment.

The commissioning procedure also entails the verification of correct metering data configuration from the meter through to the Data Acquisition System (DAS) and the Billing system (where relevant).

Figure 1 shows the components of a typical metering installation and system.

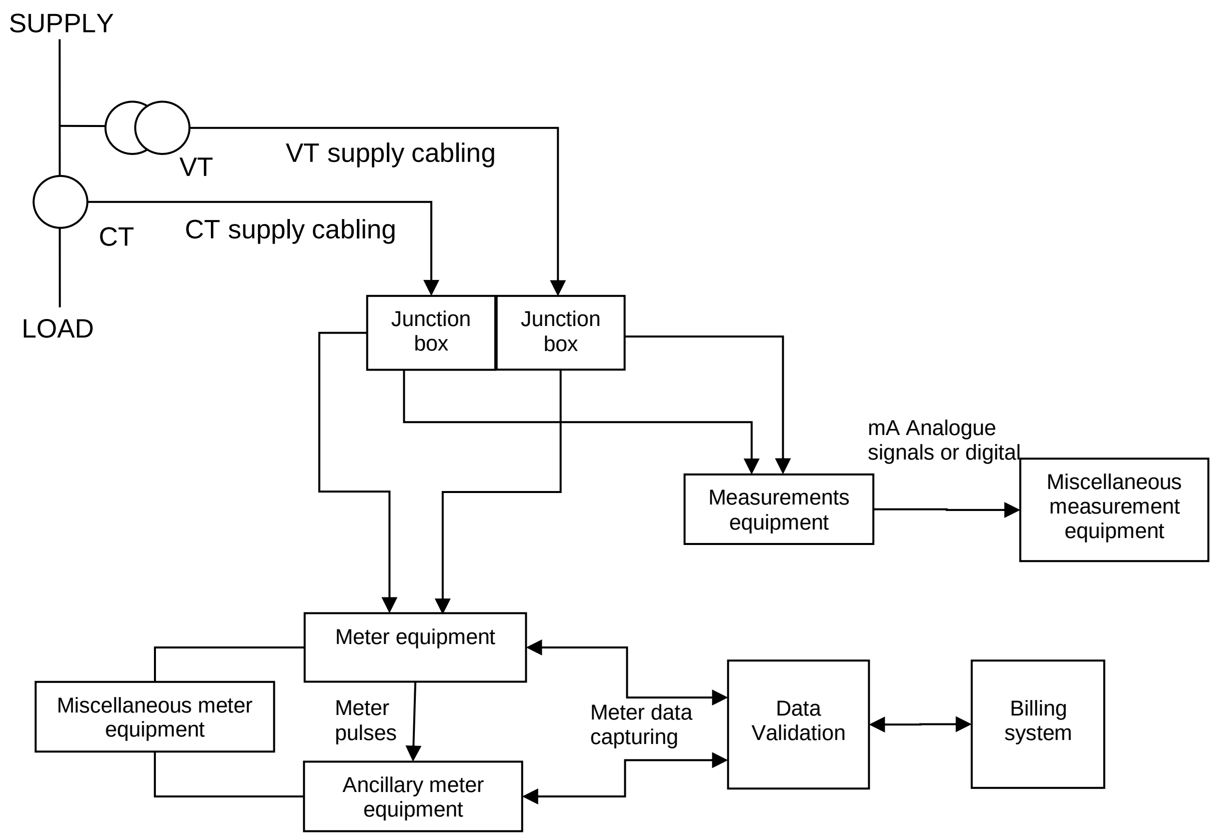

Figure 1: Metering system diagram

2. Supporting clauses

2.1 Scope

2.1.1 Purpose

This document formalizes Eskom's requirements regarding the commissioning of metering and associated equipment at all High Voltage (HV) and Medium Voltage (MV) metering points.

2.1.2 Applicability

This document shall apply throughout Eskom Holdings Limited and is applicable to all new metering installations commissioned either by Eskom staff or accredited external contractors.

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] SANS 474 / NRS 057 Code of practice for electricity metering

[3] SANS 61869-2/IEC 61869-2 Instrument transformers Part 2: Additional requirements for current transformers

[4] SANS 61869-3/ IEC 61869-3 Instrument transformers Part 3: Additional requirements for inductive voltage transformers

[5] SANS 61869-4/ IEC 61869-4 Instrument transformers Part 4: Additional requirements for combined transformers

[6] 240-62196227 Life Saving Rules

[7] 240-65216698 Test procedure for inductive and capacitive voltage transformers

[8] 240-106149404 Test procedure for inductive current transformers

[9] 240-69164883 Live method non-intrusive current transformer (CT) ratio verification

[10] 240 55198002 Standard for the verification of metering and measurements installations

[11] 240-76624511 Standard for instrument transformer burdening

[12] 240-76624513 Standard for the calibration of test instruments used by field staff

[13] 240-56364444 Standard minimum requirements for the metering of electrical energy and demand.

[14] 240-69387766 Standard for programmable meter configuration.

[15] 240-71469670 Terminology relating to the direction of power flow

[16] 240-70732868 Standard for test block connections for metering and measurement circuits

[17] 240-76628631 Standard for sealing metering equipment.

[18] 240-70732876 Metering technician tools and test equipment standard

[19] 240-62581162 Generation Energy Management and Data Acquisition System

[20] 240-44175132 Eskom Personal Protective Equipment (PPE)

[21] 240-97931387 Commissioning report for HV and MV metering installations (Excel workbook)

2.2.2 Informative

[22] TOPP-016: Use of drawings (PTM)

2.3 Definitions

2.3.1 General

Definition	Description
Active energy meter (watt-hour meter)	An instrument intended to measure active energy by integrating active power with respect to time. For metering purposes, the unit for active energy is kilowatt-hour (kWh).
Dead	Dead means that any apparatus so described is at or about zero potential and is disconnected or isolated from any live power system. Rotating plant shall not be regarded as dead until it is stationary or is being slowly rotated by means of barring gear, and is not excited.
Metering equipment	A collection of components in the metering installation, namely the instrument transformers, cables, meters, recorders and any housing and ancillary equipment such as test blocks.
Metering installation	All meters, fittings, equipment, wiring and installations used for measuring the flow of electricity.
Metering systems	Metering systems provide local and/or remote data on energy transfer. This data can be relayed to any remote billing function via a modem.
Quadrant metering (Q1, Q2, Q3, Q4)	The metering of bidirectional energy flow. This is leading and lagging reactive energy for import active energy; and leading and lagging reactive energy for export active energy. The quadrants Q1, Q2, Q3 and Q4 are defined in 240-71469670.
Reactive energy meter (var-hour meter)	An instrument intended to measure reactive energy by integrating reactive power with respect to time. For metering purposes, the unit for reactive energy is kvarh.
Verification	• Maintenance standard whereby the following are done (on site or remote): • Voltage assessment • Current assessment • Phasor verification • Scheme verification (manual read meters) o Configured tariff versus Customer Care and Billing (CC&B) data o Display sequence o Battery state o Time accuracy o VT ratio o CT ratio o Event assessments • Scheme verification (remote read meters) o Load profile channel allocation o Battery state o Time accuracy o VT ratio o CT ratio o Event assessments • Meter dial readings versus Billing data advance • Main and check comparison (where applicable)

2.3.2 Disclosure classification

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

2.4 Abbreviations

Abbreviation	Description
ac or AC	Alternating Current
Alfs	MV90 meter data repository
CAP	Committee for Accepted Products
CC&B	Customer Care and Billing [system]
CT	Current Transformer
DAS	Data Acquisition System
dc or DC	Direct Current
DMM	Digital Multimeter
ECS	Eskom Calibration Services
GM	General Manager
EMDAS	Energy Management Data Acquisition System
EOD	Electrical Operating Desk
HV	High Voltage
IDF	Intermediate Distribution Frame
LAP	List of Accepted Products
MV	Medium Voltage
n/a	not applicable
PTM&C	Protection, Telecoms, Metering and Control
rms	root mean square
SANAS	South African National Accreditation System
SC	Study Committee
SIM	Subscriber Identity Module
UPI	Units per Impulse
VT	Voltage Transformer

2.5 Symbols

Symbol	Explanation
ϕ	In this document, this symbol represents ‘phase’, e.g. red phase or blue phase.
Ø	In this document, this symbol represents the angle between voltage and current.
MΩ	Mega-ohm
μ	Micro

2.6 Roles and responsibilities

a) The designated person or his/her delegate shall ensure that this standard is implemented and adhered to.

b) The authorized/responsible person is responsible for the safe execution of all work and activities as set out in this standard.

c) Only people authorized for activities in this standard shall perform these duties.

2.7 Safety precautions

a) Whenever work is being carried out on metering installations, the following precautions shall be adhered to:

   1) Eskom's Life Saving Rules as stated in 240-62196227 shall be adhered to at all times.

   2) The prescribed protective clothing, as indicated in 240-44175132, Eskom Personal Protective Equipment (PPE) shall be worn when working on metering installations.

   3) Safe working procedures for each task to be done during commissioning. These documents are all available on the Measurements website.

b) Specifically to Generation:

   1) All work on an industrial plant must be performed under a Permit to Work in terms of Plant Safety Regulations (36-681).

2.8 Task Risk Assessment

a) It is the responsibility of each person to ensure that the correct plant is worked on/isolated according to Plant Safety regulation a permit has been issued, all staff has signed the workers register, a proper job brief has been done and that the days HIRA were done. Adhere to the OHS Act.

b) Ensure that the correct plant or equipment has been identified and ensure that when the tests or inspection are performed on the correct equipment.

c) Carry out a task risk assessment in accordance with the relevant prescribed document.

d) Ensure that all the members of the team take part when the risk assessment is carried out.

e) Check the test equipment to be in good state and fit for purpose before using them.

f) Only calibrated meters and test equipment shall be used and ensure that the certificates are valid. For a test or measurement to be legitimate, the test instruments need to be calibrated by an accredited calibration/test facility according to 240-76624513

g) Ensure that the Life-Saving rules are adhered to when performing all tasks in this document.

2.9 Personal Protective Equipment

a) All personal protective equipment shall be in accordance with 240-44175132.

b) Arch flash overhaul (Mandatory)

c) Safety shoes (Mandatory)

d) At all times personnel safety and installation security will enjoy priority over test measurements.

e) Personnel must adhere to regulations stipulated in the Occupational Health and Safety Act, and must also adhere to the local safety regulations of the station authority where the work is performed.

f) The latest revisions of the relevant drawings must be used to confirm all connections and testing points.

2.10 Asset management database

a) The operating unit must have a complete, up to date database of all the equipment that they are responsible for.

b) The purpose of the database is to have a complete overview of the plant and its condition.

c) The data on this database must be verified and updated during commissioning or if any condition on the plant change.

2.11 Drawings

a) The accountable commissioning section must have a complete set of drawings that form part of their responsibility to do commissioning on.

b) The latest revisions of the relevant drawings must be used to confirm the wiring.

c) If wire changes are done on any part of the plant, or any part of the plant are not according to the drawings the drawings must be marked-up using yellow and red according to TOPP-016.

2.12 Related/supporting documents

This document supersedes 240-55197966 revision 0 – Procedure for the commissioning of metering installations (HV & MV).

3. Requirements

3.1 General

a) The commissioning standard documents generalised testing criteria and conformances for metering installations in Eskom.

b) However, it is important to note that in certain instances these requirements may not be met due to access and/or operational constraints. In these cases it needs to be suitably motivated why requirements could not be met.

3.2 Safety

a) Safe working procedures have been created for each task to be done during commissioning. These documents are all available on the Measurements website.

b) A risk assessment shall be done before any work is commenced during commissioning.

3.3 Test equipment

a) For a test or measurement to be legitimate, the test instruments need to be calibrated by an accredited calibration/test facility according to 240-76624513.

b) Technicians shall ensure that their test equipment conforms to these requirements before any testing is done.

3.4 Pre-commissioning checks

3.4.1 General

The pre-commissioning entails the testing and checking of various components of the metering scheme prior to any of the circuits being energized. Before commencing the pre-commissioning at site, the following need to be verified:

a) Ensure that the correct metering scheme has been delivered to site, e.g. the correct metering modules, meters, communications modules, communications interface cables.

b) Check that the components of the metering scheme have not been physically damaged during delivery.

c) Ensure that the metering panel is secured and all the equipment is correctly mounted.

d) Ensure that all the installation work is complete and that the contract work and drawings have been checked and approved.

e) Ensure that the panel layout and equipment installed are in accordance with the specification drawings.

f) Ensure that the panel wiring is in accordance with the specification drawings.

g) Ensure that all the cables and wires are numbered according to the specification drawings.

h) Ensure that the proper labels are fitted to the metering scheme.

i) Ensure that all the cores are lugged and ferruled according to the specification drawings.

j) Check that the Intermediate Distribution Frame (IDF) cables are made-off and terminated in accordance with the specification drawings and IDF schedule.

k) Install any loose equipment delivered separately from the metering scheme.

l) Ensure that all test blocks are installed the right way facing up.

m) Check that the Current Transformer (CT) circuit test blocks have shorting strips connected on the supply side and that the connections are tight.

n) Check and test that it is shorted-out between all CT phases and neutral on the supply side of the CT test block when the cover is removed.

o) Check that the Voltage Transformer (VT) circuit test blocks do not have shorting strips.

p) Check that flat washers and spring washers were used in the test block connections.

q) Check that all connections are tight.

3.4.2 Current transformer tests

3.4.2.1 General

Detailed testing requirements for CTs are listed in 240-106149404. The document lists the purpose, the procedure and the expected results of each test. This procedure will not duplicate that text, but will only list what tests need to be done and provide acceptance criteria for each test.

The tests on CTs need not necessarily be done by the metering technician. However, the metering technician shall ensure that the tests are conducted appropriately and that all the test results are attached to the commissioning records. If the tests are to be conducted by a metering technician and if such tests could have an influence on the protection, e.g. Buszone, then either the responsible protection personnel shall be present when the tests are to be conducted, or the protection personnel shall provide authorization prior to any test being conducted by the metering technician.

Prior to any tests being conducted, ensure that the CTs have been calibrated and that the test certificates are available. Attach a copy of the CT test certificates to the commissioning records.

Note 1: Modern, high-accuracy CT test equipment has become available to perform the full scope of testing on a CT, including magnetizing tests; accuracy of the ratio and phase angle; and CT polarity. Where these tests are done via the CT test equipment, then a copy of the results shall be filed instead of the individual test results as listed below.

Note 2: The CT test instrument's accuracy shall be at least two times better than the accuracy class of the CT core under test.

3.4.2.2 Current transformer insulation resistance test

a) Equipment

   1) Insulation resistance test instrument, 500V and 5kV.

b) Procedure

1) Perform an insulation resistance test at 5 kV between the primary and each secondary winding. All secondary windings and the tank shall be earthed. This is to test the primary-to-earth and primary-to-secondary insulation.

2) Perform an insulation resistance test at 500 V between the secondary windings of each core. The secondary windings not under test and the tank shall be earthed. This is to test the insulation resistance between the secondary windings of each core and to the tank.

c) Acceptance criteria

1) The primary-to-earth and primary-to-secondary insulation resistance shall be > 2 MΩ/kV (e.g. 264 MΩ for a 132 kV CT).

2) The secondary-to-earth insulation resistance shall not be < 20 MΩ.

3.4.2.3 Current transformer magnetizing test

a) Equipment

1) CT test instrument (Omicron CT Analyser or similar).

b) Procedure

1) Perform the magnetizing test and record the results in the commissioning records.

c) Acceptance criteria

1) The results of the test shall be compared with those from previous tests on the same CT, and/or with results from other CTs of the same make and type.

2) Any deviation may indicate inter-turn or lamination faults.

3) Deviations in results between new CTs of the same type from the same manufacturer may indicate irregularities in the core annealing process.

3.4.2.4 Current transformer ratio and phase angle accuracy test

a) Equipment

1) CT test instrument (Omicron CT Analyser or similar).

a) Procedure

1) Perform the ratio and phase angle accuracy test and record the results in the commissioning records.

b) Acceptance criteria

1) The ratio and phase angle errors should be within the limits as specified in SANS 61869-2/IEC 61869-2 for measuring CTs.

3.4.2.5 Current transformer polarity test

a) Equipment

1) CT test instrument (Omicron CT Analyser or similar).

b) Procedure

1) Perform the polarity test and record the results in the commissioning records.

3.4.2.6 Current transformer cabling connections

a) Equipment

1) Insulation resistance test instrument, 500 V.

b) Procedure

1) Connect all the terminations on one side of all the cables together and to earth using a bare copper wire.

2) With the insulation test instrument selected to ‘500 V’, test each core from the unearthed side of the cable to earth. A low reading on the mega-ohm range should result.

3) Remove each core in turn from the earth and test the core again. A reading that is high on the mega-ohm range should result. A reading of < 2 MΩ is suspect and shall be investigated.

4) Connect all the cables to the appropriate terminals using the drawings as a reference.

NB: Be sure to use lugs on each connection, as well as spring and flat washers on the lugs with stud connections.

5) Do tightness checks on each wire connected.

3.4.2.7 Current transformer injection test

a) General

1) This test is done after the CT cabling has been connected to the CT and the metering equipment. A CT ratio test will be done to ensure that the correct ratio is connected and that there is continuity in the CT circuits up to the metering equipment.

b) Equipment

1) Appropriate ampere current injector (20% of rated current where possible).

2) Two root mean square (rms) digital multimeters.

3) Clamp-on CT. Figure 2 shows the test equipment connections to the CT.

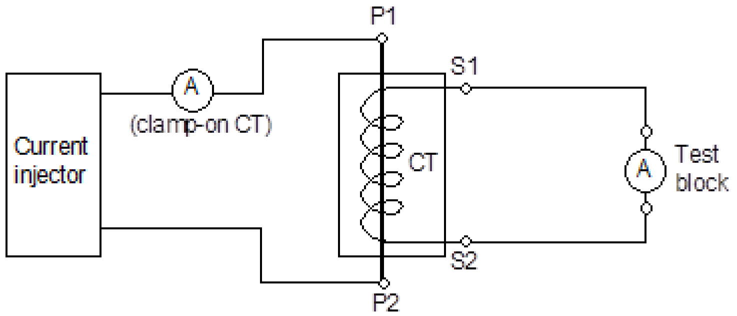

Figure 2: Ratio test equipment connections to the current transformer

c) Procedure

NB: With multicore CTs, the cores that are not under testing shall be short-circuited (e.g. check CT core, protection cores). When testing bushing CTs on power transformers, do not short out the test winding.

1) Connect the test circuit in accordance with Figure 2.

2) Switch on the AC power to the current injector and turn the variac knob until a primary current of 10 A is flowing through the CT.

3) Measure the voltage across each CT core with the other digital multimeter, which must be selected to ‘AC volts’.

Note: Voltages not higher than 10 V should be measured. If the voltage exceeds 10 V, then the CT is open circuit. Stop the test and rectify the problem.

4) Increase the current to match the connected CT ratio. Twenty percent of rated current is sufficient to prove the ratio.

5) Measure the current on the meter panel at the CT test block.

6) Turn the current injector off and calculate the CT ratio using the following formula:

$$CT\ Ratio = \frac{\text{Primary test current}}{\text{Secondary test current}}$$

d) Acceptance criteria

1) The ratio as calculated shall not differ by more than 5% from the nameplate ratio.

3.4.3 Summation current transformer checks (if applicable)

Note 1: The accuracy of the summation CT is critical to the accuracy of the total installation.

Note 2: The connected ratios of the individual CTs that are to be summated by means of the summation CT shall be the same.

Note 3: Summated CTs may only be used if the VT supply is common and applicable to all individual feeders (e.g. busbar VTs).

a) Ensure that the entire plant is de-energized, and all secondary currents feeding the summation CT are also de-energized.

b) As the installation is de-energized, the summation CTs shall be given a polarity test and an injection test.

c) For a 4:1 summation CT, the secondary current shall be a quarter of the total summation CT primary current, when one input is supplied with a current.

Example: Summation CT type 5+5+5+5/5 A.

Supply any one of the primaries with 5 A, with the remaining three primaries remaining open. A current of 5 A/4 A = 1,25 A shall be measured on the secondary. If, however, any one of the primaries is short-circuited, the secondary measured current will be lower than the calculated secondary value. For this reason, all unused primaries shall be left open circuit.

d) For a 2:1 summation CT, the secondary current shall be half of the summation CT primary current. The same principles as explained above will apply.

e) When on-load, measure the primary values with a clip-on ammeter and reconcile this measurement with the measured secondary value.

3.4.4 Voltage transformer tests

3.4.4.1 General

Detailed testing requirements for VTs are listed in 240-65216698. The procedure lists the purpose, the procedure and the expected results of each test. This procedure will not duplicate that text, but will only list what tests need to be done, and provide for acceptance criteria for each test.

The following tests need not necessarily be done by the metering technician. However, the metering technician shall ensure that the tests are conducted appropriately and that all the test results are attached to the commissioning records. If the tests are to be conducted by a metering technician and if such tests could have an influence on the protection, then either the responsible protection personnel must be present when the test are to be conducted, or the protection personnel must provide authorization prior to any test being conducted by the metering technician.

Prior to any tests being conducted, ensure that the VTs have been calibrated and that the test certificates are available. Attach a copy of the VT test certificates to the commissioning records.

Note 1: Modern, high-accuracy VT test equipment has become available to perform the full scope of testing on a VT. Where these tests are done via the VT test equipment, then a copy of the results shall be filed instead of the individual test results as listed below.

Note 2: The VT test instrument's accuracy shall be at least two times better than the accuracy class of the VT winding under test.

3.4.4.2 Voltage transformer insulation resistance test

a) Equipment

1) Insulation resistance test instrument, 500V and 5kV.

b) Procedure

1) Open the primary winding earth link and perform an insulation resistance test at 5 kV between the primary and each secondary winding. All secondary windings and the tank shall be earthed. This is to test the primary-to-earth and primary-to-secondary insulation.

2) Perform an insulation resistance test at 500 V between the secondary windings. The secondary windings not under test shall be earthed. The winding under test should not be earthed (i.e. open/remove the neutral link). The other secondary windings should be earthed. This is to test the insulation resistance between the secondary windings and earth.

3) Perform a wiring insulation test of all secondary wiring in use at 500 V between wiring and earth. The secondary circuit earth connection within the VT junction box shall be temporarily disconnected. The test is repeated with the secondary circuit earth connection closed to confirm the presence of a single earth connection.

c) Acceptance criteria

1) The primary to earth and primary to secondary insulation resistances shall be > 2 MΩ/kV (e.g. 264 MΩ for a 132 kV VT).

2) The secondary to earth insulation resistance shall not be < 20 MΩ.

3.4.4.3 Voltage transformer ratio test

a) Equipment

1) VT test instrument (Omicron Votano or similar).

b) Procedure

1) Disconnect any substation conductors from the HV terminal of the VT.

2) Use a ratio meter/modern test set to measure the VT ratio and the phase angle error. This test is done by applying a voltage to the primary side of the VT, and measuring the voltage on the secondary side.

3) For single-phase VTs, the test voltages are injected and measured phase-to-neutral. For a three-phase VT with an internal star point, inject and measure the test voltages phase-to-phase: injecting first on HV Red-to-White and measuring LV Red-to-White, then repeating for White-to-Blue and Blue-to-Red

c) Acceptance criteria

1) The ratio is calculated as the quotient of the primary test voltage and secondary voltage (both measured phase-to-neutral or phase-to-phase).

2) The ratio should be confirmed to within 1% of the rated transformation ratio.

3.4.4.4 Voltage transformer polarity test

a) Equipment

1) VT test instrument (Omicron Votano or similar).

b) Procedure

1) Perform the polarity test and record the results in the commissioning records.

3.4.4.5 Voltage transformer cabling insulation resistance test

Follow the same procedure as specified for CT cables in 3.4.2.6.

3.4.4.6 Current transformer/voltage transformer units

The CT/VT unit shall be tested to the same requirements as listed in 3.4.2 for CTs and in 3.4.4 for three-phase VTs.

3.4.5 Meter panel functional tests

3.4.5.1 Calibration test certificates

a) Ensure that the original SANAS test certificates for each of the meters have been delivered with the metering scheme.

b) Attach the test certificates to the commissioning records.

3.4.5.2 Meter configuration

a) Configure the meters with the applicable configuration program for that particular meter.

b) Ensure that the correct CT and VT ratios have been implemented for primary read meters.

c) Verify that the display sequence is in accordance with the applicable meter configuration standard 240-69387766.

d) Verify that the meter's channel allocation (half-hourly metering data recording – or hourly for Generation) is in accordance with the applicable channel allocation standard.

e) Where applicable on Transmission points, ensure that the line loss compensation has been activated on the meters, and that the applicable parameters have been programmed onto the meter for international metering point installations where the point of supply is contractually placed at a geographical boundary, and not at the metering installation

f) Synchronize the time on all the applicable equipment with real time at that stage.

g) The configuration programme on each meter shall be saved and attached to the commissioning records.

3.4.5.3 Voltage fail alarms

Verify the correct functionality of VT phase fail and auxiliary supply alarms through to supervisory /EOD / EMDAS (where applicable).

3.4.5.4 Customer pulses (if applicable)

a) Verify the correct functionality of customer pulses.

b) Ensure that the customer's cables are connected onto the correct terminals.

c) Inform the customer of the multiplication constants of the pulses (Units per Impulse (UPI)).

3.4.5.5 Secondary Injection tests

a) General

1) This check is not intended to calibrate meters. This test is to confirm the integrity of the panel wiring together with the meters and/or measurement equipment

Note: The meters shall be calibrated before stores issue by an approved South African National Accreditation System (SANAS) calibration facility.

b) Equipment

1) Omicron injection set or similar

c) Procedure

1) Refer to relevant equipment set-up procedures.

2) Isolate the metering circuits from the primary plant (CTs and VTs).

3) Read all meter and recorder (where relevant) registers before and after completion of the tests.

4) Inject the circuits with a current and voltage injection set, and verify the integrity of the panel wiring. An accuracy test (injected at 50% load - pf 30° lagging) shall be done to verify the accuracy of active energy and reactive energy.

d) Testing criteria

1) If the accuracy values of a meter under test show that it is outside the specifications set for that accuracy class of the instrument, then the meter shall be removed and be tested in an accredited SANAS/Eskom Calibration Services (ECS) laboratory to determine if the meter is acceptable for installation.

3.4.5.6 Data Acquisition System configuration

a) General

1) The following tests are intended to ensure that the meter point is correctly set up on the DAS and that the DAS is able to communicate to and retrieve data from all the meters. In addition, the meter and recorder register advances during the accuracy verification tests will be compared to data retrieved by the DAS in order to verify the correct channel configurations on meters/recorders and DAS; and the correct implementation of pulsing factors, meter constants and CT and VT ratios on the DAS.

b) Procedure

1) Ensure that all communication profiles have been programmed correctly. If multiple communications modules are utilized for cascading of the meters, ensure that each module is programmed correctly.

2) If a GSM/GPRS modem is to be utilized, ensure that the Subscriber Identity Module (SIM) card is registering on the network and that the signal strength is acceptable. Ensure that the modem is programmed correctly, i.e. auto answer is switched on, the baud rate is correct and character framing has been set up.

3) Complete the DAS check sheets and send a copy to the DAS operators.

4) Request the DAS operators to set up the meters on the DAS as per the check sheets.

5) Request the DAS operators to test the communications to all the meters. If the DAS operators are unsuccessful, verify all the communication settings on the modems, meters and recorders.

6) Request the DAS operators to download the meter load profile data for the intervals during which the meter accuracy verification was conducted, and compare this to the data on the meters.

Note: For Generation EMDAS requirements refer to Standard 240-62581162 Generation Energy Management and Data Acquisition System

3.5 Commissioning tests

3.5.1 General

Commissioning tests are done during energization of the bay (feeder, transformer).

3.5.2 Measurement checks

The following equipment is required:

a) Digital multimeter.

b) Test plug.

3.5.2.1 Voltage measurement

a) Use the digital multimeter to measure the voltage on the mains, and check the VT test blocks, using the following sequence:

   1) Red – neutral; 63,5 V.

   2) White – neutral; 63,5 V.

   3) Blue – neutral; 63,5 V.

   4) Red – white; 110 V.

   5) White – blue; 110 V.

   6) Blue – red; 110 V.

b) A preferred alternative is to record the voltage from the meter display, if this is supported by the meter.

Note 1: If the measured phase-to-neutral or the phase-to-phase voltages differ by more than 5% from each other, then either a VT fuse is blown or the VT may be defective.

Note 2: A voltage higher or lower than 10% of the norm is unacceptable and shall be reported to be rectified at power plant level.

3.5.2.2 Voltage selection verification

a) Where the meter panel utilise voltage selection equipment, verify that the voltage selection equipment is operating as required.

   1) Remove the VT fuses or disconnect the MCBs at one of the VT junction boxes or switchgear terminal compartment.

   2) Verify that the voltage switch over to the other circuit.

b) Verify if the correct default voltage transformers are linked to the relevant meters.

   1) Verify to which busbar the metering VT circuit should be connected.

   2) Remove the fuses or disconnect the MCBs at the VT junction box or switchgear terminal compartment of that busbar.

   3) The voltage selection equipment shall operate to switch over to the other VT circuit.

3.5.3 Measurement of instrument voltage and current transformer installed circuit burdens

Note: Not applicable to Generation due to restrictions on testing under live conditions.

3.5.3.1 General

a) Two values shall be measured when determining voltage circuit burdening, namely the voltage drop across the voltage leads from the VT to the energy meter, and the burden on the VT itself.

b) Burden measurements need only to be done on category A customers (customers with a notified demand > 10 MVA) as a minimum.

c) Refer to the relevant standard 240-76624511 for general information on burdening.

3.5.3.2 Voltage drop across voltage leads

a) A theoretical calculation of voltage drop shall be done by using the volt-drop properties of the installed cable to the VT to identify possible non-conformances to the values listed in Table 1.

b) If the calculated voltage drop is higher than the values listed, then the transducer test shall be done to confirm results and corrective action shall be done to limit the loading on the cables (install additional cables – double-up of cabling or remove equipment from the same circuit via auxiliary supplies from the substation).

Table 1: Guide to voltage drop limits

Class of energy meter	Voltage drop limit (same as energy meter class)
	Phase-to-neutral voltage (63,5 V)
0,2	127 mV
0,5	318 mV
1	635 mV

3.5.3.3 Voltage drop calculation

a) Equipment

1) Digital multimeter (4½ digit).

b) Procedure

1) Measure the current in the red phase voltage circuit.

2) Determine the length of cable installed between the VT and meter panel.

3) Use the following formula to calculate the voltage drop on the circuit:

$$V_{Drop} = \frac{V_{Drop\ Value} \times A \times L_{Cable}}{1\ 000}$$

where

$V_{Drop\ Value}$ = 6.4 mV/A/m for 6 mm^2 cable, 9,6 mV/A/m for 4 mm^2 cable and 15,4 mV/A/m for 2,5 mm^2 cable;

L_{Cable} = length of cable in metres;

A = current in circuit.

4) Compare with the limits as specified in 1.

5) Repeat for all voltage phases and circuits.

3.5.3.4 Voltage drop transducer test across voltage leads

a) Equipment

1) 2 × Mean (self-powered) voltage transducers (calibrated as a pair).

2) Digital Multimeter (DMM) (4½ digit) with DC 200 µA scale.

3) Leads from VT junction box to metering panel (twisted pair).

b) Procedure

1) Take extreme precautions, as this test is done under live conditions.
2) Connect one voltage transducer to the red phase voltage circuit in the VT junction box. (A self-powered transducer is used to minimize connections.)
3) Connect the second transducer to the metering panel at the VT test block.
4) Connect the milliamp output of the two transducers back to back, with the micro-ammeter across the output of the transducer at the meter panel, as shown in Figure 3.
5) The ammeter will have no reading if there is no voltage difference. Any difference will be shown by the milli-ammeter and shall be converted to a voltage reading.

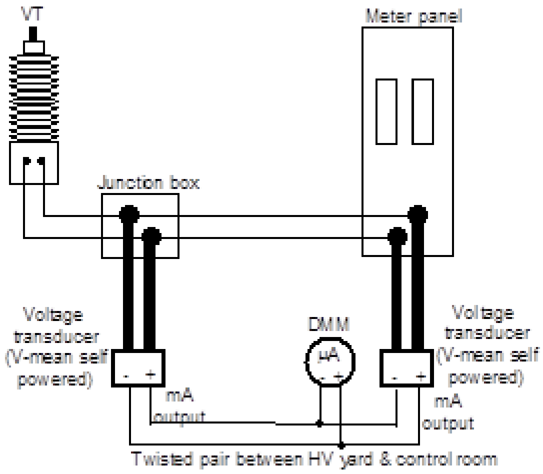

Figure 3: Voltage drop measurement connection diagram

c) Testing criteria

1) If a transducer with a full-scale input voltage of 63,5 V has a DC milliamp output of 5 mA, then a micro-amp reading of 50 μA on the digital multimeter will represent a 1% voltage drop.

Note: This calculation will depend on the type of transducer used. It is advisable to use a transducer of 20 mA output at 63,5 V, as this will ensure better resolution.

2) Repeat for the remaining two phases.

Note: There is new test equipment available catering for this test which can also be used.

3.5.3.5 Voltage transformer burden measurement

a) Equipment

1) 1 × digital current clip-on meter.
2) DMM (4½ digit) with DC 200 μA scale.

b) Procedure

1) Take extreme precautions, as this test is done under live conditions.
2) Measure the voltage of the red phase VT in the junction box with the DMM.
3) Measure the current drawn from the red phase VT in the junction box with the clip-on meter.
4) Multiply the voltage by the current to obtain the VA value.

c) Testing criteria

1) Ensure that the measured VA value is less than the VA specified on the VT.

2) Repeat for the remaining two phases.

3.5.3.6 Current transformer burden measurement

a) Equipment

1) 1 × digital current clip-on meter.

2) DMM (4½ digit) with 200 µA DC scale.

b) Procedure

1) Take extreme precautions, as this test is done under live conditions.

2) Measure the voltage (V_m) across the red phase CT terminals in the junction box with the DMM.

3) Measure the current (I_m) drawn from the red phase CT in the junction box with the clip-on meter.

4) Calculations:

CT Burden (VA) = $I_{nominal} \times V_c$

where $V_c \; \frac{V_m \times I_{nominal}}{I_m}$

and $I_{nominal}$ = 1 A or 5 A

c) Testing criteria

1) Ensure that the measured VA value is less than the VA specified on the CT.

2) Ensure that the voltages measured between the phases and ground are of the same order. If the voltage recorded is found to be > 5 V, then the circuit shall be investigated for loose connections.

3) Repeat for the remaining two phases.

3.5.3.7 Time accuracy on meters and recorders (where applicable)

Synchronize the time on all the applicable equipment with real time at that stage.

3.6 Post-commissioning tests

These tests shall be done once load is taken by the customer.

3.6.1 Phasor test

a) A phasor diagram shall be compiled in order to verify the correctness of the metering installation. This is done to determine if the red phase current is used with the red phase voltage, white phase current with white phase voltage, etc. This method will also show reversed polarities.

b) It is best practice to obtain these values from the meter itself if the meter supports this functionality.

c) Record the phasor diagram after the relevant phasor values have been determined.

d) Confirm the correctness of the installation.

Note: For Generation the phasor diagram can only be obtained through the meter (when supported) due to restrictions on on-load testing

3.6.1.1 Voltage measurement verification

a) Record the voltage from the meter display, if this is supported by the meter or from the phasor test instrument.

Note 1: If the measured phase-to-neutral or the phase-to-phase voltages differ by more than 5% from each other, then either a VT fuse is blown or the VT may be defective.

Note 2: A voltage higher or lower than 10% of the norm is unacceptable and shall be reported to be rectified at power plant level.

3.6.1.2 Current measurement verification

Three-phase three-wire systems: Due to loading conditions, the currents may be low. However, they should be balanced and the neutral current should be of the same magnitude as the red phase and blue phase currents. If the neutral current is approximately double that of the two-phase currents, this is an indication that one of the two CT polarities is incorrect. If this is the case, the test shall be stopped and the problem rectified.

Three-phase four-wire systems: Due to loading conditions, the currents measured may be low. However, they should be balanced and the neutral current should be close to zero, with the red phase, white phase and blue phase currents balanced and larger than the neutral current. If the neutral current is approximately double that of the three-phase currents, this is an indication that one of the three CT polarities is incorrect. If this is the case, the test shall be stopped and the problem rectified.

Note 1: When the meter or phasor test instrument does not record the neutral current, then it will be measured in the neutral CT circuit with a clip-on CT.

Note 2: An outage is required for Generation to rectify the problem.

3.6.2 Installation verification check

3.6.2.1 On-load current transformer ratio check

a) Methods

The ratio can be confirmed by using one of the following methods:

1) The CT ratio (for installations up to 132 kV) can be confirmed by using a hook-on or clamp-on CT certified for live work use for the specified voltage, to measure the primary current and at the same time (if this function is supported by the meter), or to measure the secondary current at the test blocks, and then calculate the ratio, using the following formula:

$$CT\ Ratio = \frac{\text{Primary test current}}{\text{Secondary test current}}$$

This procedure is described in detail in 240-69164883.

2) In most substations, indication of primary currents is provided for the different feeders on the protection panels by means of analogue meters. By using this indicated primary current value, and reading the secondary current from the meter or measuring the secondary current at the meter test block, the ratio can be calculated by using the same formula as in 3.6.2.1.a).1).

3) If there is no indication as stated in 3.6.2.1.a).2)2), but one of the protection CT ratios from the same primary circuit is known, then the secondary current of that protection circuit is to be measured and this value can then be used to verify the metering CT ratio:

- Measure the protection secondary CT current.
- Read from the meter or measure the metering secondary current.
- Determine the metering CT ratio:

$$CT\ Ratio = \frac{(\text{Protection known ratio} \times \text{protection secondary current})}{\text{Metering secondary test current}}$$

Note: Only method 2 will be used in Generation

b) Testing criteria

1) The ratio as calculated shall not differ by more than 5% from the nameplate ratio.

2) If the ratio differs by more than 5% from the nameplate ratio, then an outage shall be arranged to rectify this.

3.6.3 On-load meter accuracy check

An on-load accuracy check for both active and reactive energy shall be performed by means of substandard meter test equipment (e.g. Landis+Gyr TVE 102/3 or Kocos Metes).

NOTE: Not applicable to Generation due to restrictions on on-load testing

3.6.4 Sealing

Ensure that all metering equipment is sealed in accordance with 240-76628631.

NOTE: Not applicable to Generation

3.7 Verification

A work order shall be created to schedule a verification procedure in accordance with 240-55198002 within three months after the commissioning date.

3.8 Documentation

a) All documentation shall be signed by the commissioning person and authorized by his/her section head.

b) If an electronic filing system is used then a paper copy of the first page of the records shall be signed by the commissioning person and the section head where-after the paper copy will be scanned and attached to the rest of the records.

c) Commissioning notification shall be given to the DAS, plant, Billing department and Customer Services where relevant.

d) All the test sheets and calibration certificates shall be filed or saved in the relevant customer records for future reference.

4. Authorization

This document has been seen and accepted by:

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Danie Odendaal	Senior General Manager: Engineering (Acting)
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5. Revisions

Date	Rev.	Compiled By:	Clause	Remarks
March 2017	2	HPD Groenewald	-	Reference documents numbering changed to new SANS numbers and Eskom 240… numbers.
			3.4.2.1	Automated testing with the use of modern equipment
			3.4.4.1	Automated testing with the use of modern equipment
			3.4.4.6	CT/VT units shall be tested to the same requirements as for stand-alone CTs and VTs
			3.4.5.5.b.1	Reference to supplier specific equipment removed
March 2013	1	H P D Groenewald	-	Combined the requirements of Distribution, Transmission and Generation.
			4.2	Added paragraph on test equipment requirements.
			4.3.2	Aligned CT testing requirements with the Distribution procedure DPC 34-1035.
			4.3.3	Aligned VT testing requirements with the Distribution procedure DPC 34-1033.
			4.3.3.3	Revised requirements for VT ratio testing.
			4.3.4.1	Added requirements on calibration certificates.
			4.3.4.2	Added requirements for meter configuration.
			4.3.4.6	Added requirements on DAS configuration.

6. Development team

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

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- Sello Lekalakala — PDE SI Limpopo Operating Unit

7. Acknowledgements

Not applicable.

Annex A – Old test procedures

1) Current transformer magnetizing test (Applicable to high voltage CTs)

a) Equipment

1) Rms digital multimeter (used as the ammeter).
2) Rms digital multimeter (used as the voltmeter).
3) 15 A Variac.
4) Step-up transformer (220 V to 3 000 V) with dead-man switch.
5) Various test leads.

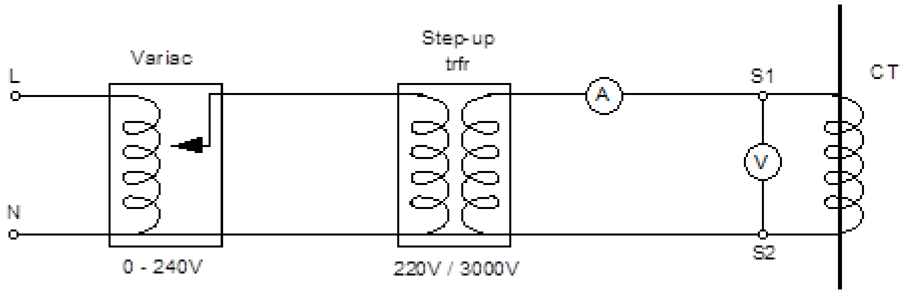

Figure A.1: Magnetizing test equipment connections to the current transformer

b) Procedure

1) Connect the equipment in accordance with Figure A.1.
2) Have another technician check the test equipment wiring for correctness.
3) Turn the variac control knob slowly clockwise in steps of 10 V. Record both the voltage and current at each stop. When the current increases rapidly, the recording steps can be reduced to 5 V. The knee-point voltage of the CT is reached when a 10% rise in voltage results in a 50% rise in current. Record the value of the knee-point voltage.
4) Once the knee-point voltage has been exceeded and the CT saturated, slowly turn the variac knob anticlockwise, thereby reducing the voltage. This shall be done in steps of 5 V near the knee-point voltage and in steps of 10 V below the knee-point voltage. Record both the voltage and its corresponding current at each step.
5) Under no circumstances shall the voltage be turned up again to attain a certain voltage level. If the required level is passed accidentally, take the recording where the stop occurred. If this is not done, the hysteresis effect may cause the magnetizing curve to be incorrect.

2) Voltage transformer polarity test

a) Equipment

1) Battery (9 V to 12 V) dry cell.
2) Analogue (centre zero) or digital multimeter.
3) Various test leads.

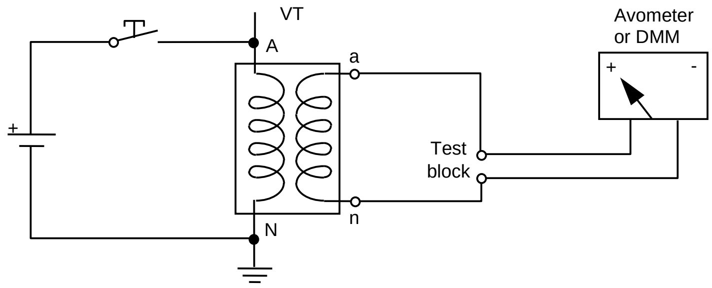

Figure A.2: Polarity test equipment connections to the voltage transformer

b) Procedure for a single-phase voltage transformer arrangement

1) Connect the test circuit in accordance with Figure A.2.
2) Apply a pulse at the VT.
3) A positive deflection will result if the VT and test connections are correct.

c) Procedure for three-phase voltage transformers

1) Connect the positive side of the battery to the red phase VT HV terminal, and the negative side of the battery to the white phase VT HV terminal.
2) Connect the positive lead of the analogue or digital multimeter to the red phase terminal on the VT test block, and the negative lead of the analogue multimeter to the white phase terminal on the test block.
3) Apply a pulse at the VT.
4) A positive deflection will result if the VT and test connections are correct.
5) Repeat the test for the white phase to blue phase and the blue phase to red phase.

3) Installation verification check

(Additional method of verification of meter – particularly useful with electromechanical meters.)

a) Equipment

1) 1 × DMM.
2) 1 × Clamp-on CT.
3) 1 × Stopwatch.

b) Procedure

1) Measure the current in the red phase with the clamp-on CT or multimeter and the phase-to-phase voltage.
2) At the same time, measure the elapsed time for 10 revolutions of the disc of the meter; or, with solid state meters, a minimum of 10 impulses from the meter.
3) Use the following formula to calculate the secondary power of the metering installation:

$$P_w = \frac{3\,600 \times 1\,000 \times n}{\mathrm{c} \times \mathrm{t}}$$

Where

N = number of revolutions

C = meter constants (revs/kWh or impulses/kWh)

T = time in seconds

4) For Sangamo meters such as the CYLP and the Fulcrum where the calibration constant is given as ‘kh’, use the following example to convert it to revolutions per kWh:

If kh = 0,72, then:

$$\frac{1\,000}{0{,}72} = 1\,388\, revs/kWh$$

$$P_{var} = \frac{3\,600 \times 1\,000 \times n}{\mathrm{c} \times \mathrm{t}}$$

Where

n = number of revolutions

c = meter constant (revs/kvarh or impulses/kvarh

t = time in seconds

then

$$\mathrm{VA} = \sqrt{\mathrm{P}_{\mathrm{W}}^{2} + \mathrm{P}_{\mathrm{var}}^{2}}$$

5) Verify this value against the value obtained from the secondary power calculated from the measured voltage and current, i.e.:

$$P = \sqrt{3 \times V \times I}$$

Where

V = phase-to-phase voltage ($V_{red} - V_{white}$); and

I = current measured with the clamp-on meter.

6) This should read approximately the same.

7) For watt demand only, the Wh meter will be available.

8) Verify the P_W value as obtained above with the value obtained from the secondary power calculated from the measured voltage and current, i.e.:

$$P = \sqrt{3} \times V \times I \cos\emptyset$$

Where

V = phase-to-phase voltage ($V_{red} - V_{white}$);

I = current measured with the clamp-on meter; and

ϕ = angle between voltage and current as obtained from the phasor diagram.

4) Installation verification check (electronic meters)

a) Procedure

1) For modern electronic meters, the installation can be verified on site by comparing the primary power with the power registered by the meter.

2) Calculate the primary power by:

3) Measuring the primary current or calculating the primary current via protection CT circuits or protection equipment; and

Using the formula

$$P_{primary} = \sqrt{3} \times V_{phase-phase} \times I_{primary}$$

4) Calculate the difference between primary and meter reading

$$Error = \frac{P_{primary-} \, P_{meter}}{P_{primary}} \times 100$$