# Electricity Policy Document 350

Issue 6 March 2023

# Protection for 132kV, 33kV and 11/6.6kV Systems

# Amendment Summary

| ISSUE NO. DATE | DESCRIPTION |
|---|---|
| **Issue 6**<br><br>**MAR 2023** | Document updated into the new template and additional definitions added to cover for new systems in use on the network. Updated the acronyms in use throughout the document to reflect the new systems.<br><br>Prepared by: Simon Rushton<br>Approved by: Policy Approval Panel<br>and signed on its behalf by Steve Cox, DSO Director |

## Contents

# 1 Introduction

This document states the Electricity North West Limited policy for protection for all high voltage systems. It is intended to state the basis for the protection systems and settings in use throughout the Electricity North West Limited network.

# 2 Scope

This document covers protection policy for the 132, 33 and 11/6.6kV systems. Guidance on settings for the 132kV system is given in CP338, and for the 33kV and 11/6.6kV systems are given in Code of Practice (CP) 373. The protection of plant and circuits on the 11/6.6kV (excluding primary substations) and 400V networks is covered by CP331, which details standard relay settings and fuse sizes to be used.

# 3 Definitions

| | |
|---|---|
| **AUTO CLOSE** | A scheme that is generally used to restore supplies. During the Auto Close sequence the automatic operation to “Auto open” a CB,is a function of the overall restoration sequence. |
| **ALRS** | Automatic Load Reduction Scheme – This scheme involves a measurement and a time period to remove demand |
| **CROSS TRIP** | Cross Trip schemes - when an action is performed because of another action with no delay. Cross tripping is applied within the local substation. |
| **FLISR** | Fault Localisation, Isolation and Supply Restoration – an automated NMS control system algorithm that when triggered by the relevant events and protection alarms will attempt location and isolation of a fault and supply restoration of de-energised customers by operating remotely controllable switching devices. |
| **BEF** | Balanced Earth Fault. A form of earth fault protection that operates from the summation of 3-phase circuits. This is usually applied to the source end of feeder transformers. |
| **CT** | Current Transformer |
| **DAR** | Delayed Auto Reclosing – a system for reclosing a circuit breaker under fault conditions usually incorporated within a relay |
| **DOC** | Directional Overcurrent – a form of overcurrent protection which operates for fault current flowing in a particular direction. |
| **EF** | Earth Fault – a form of protection which operates when fault current flows to earth within the protected zone. |
| **EI** | Extremely Inverse. |
| **HSOC** | High Set Overcurrent – a form of overcurrent protection which operates at a higher current and in a faster time than IDMT overcurrent. |
| **IDMT** | Inverse Definite Minimum Time – a protection curve where the time of operation is inversely proportional to the fault current level but with a definite minimum operating time at the highest current setting. The curves used are Standard Inverse, Very Inverse, Extremely Inverse or Long Time Inverse and are based on formulae defined in BS EN 60255-3. |
| **LTI** | Long Time Inverse. |

Mar 23

| | |
|---|---|
| **NER** | Neutral Earthing Resistor – a resistance applied to the star point of a transformer to restrict earth fault current flowing on the network to specific values. |
| **NMS** | Network Management System – the new control room system. |
| **NVD** | Neutral Voltage Displacement – a form of protection which operates following detection of a change in the neutral voltage. |
| **OC** | Overcurrent – a form of protection which operates when the current flowing exceeds a level set in the relay. |
| **REF** | Restricted Earth Fault – a form of earth fault protection covering a specific "restricted" zone. It operates by comparing the summation of the current in the 3 phase circuits and the current in the neutral CT; the location of the CTs defines the "restricted" zone. |
| **SI** | Standard Inverse |
| **SBEF** | Standby Earth Fault – a form of earth fault protection which acts as a back-up to the main earth fault protection |
| **SEF** | Sensitive Earth Fault – a form of earth fault protection that detects high impedance earth faults. |
| **TDAR** | Telecontrol Delayed Auto Reclose – part of the FLISR system that will provide software delayed auto-reclosing to a circuit breaker. It is a software driven auto-reclosing algorithm which can be selected on nominated circuits allowing re-energisation of those circuits with relevant overhead line components for a fault. This system can only work with either IDMT or Instantaneous protection but not both as a hard-wired DAR scheme would. |
| **LAR** | Large Area Restoration – an automated NMS control system algorithm that when triggered by relevant events and protection alarms will attempt to restore healthy parts of the network affected by the fault(s). It is used for faults within Primary substations and on the 33kV and 132kV networks. |
| **VCOC** | Voltage Controlled Overcurrent – a form of overcurrent protection which uses voltage control to modify the setting under phase fault conditions. |
| **VC** | Voltage Control |
| **VI** | Very Inverse |

Mar 23

# 4 General

The protection systems currently in use throughout Electricity North West Limited combine both older electromechanical relays and modern microprocessor based systems. The majority of relays that will be found on the system are of the older electromechanical type but any differences will be noted below.

The aim of the protection system is to disconnect as quickly as possible any part of the power system in which a fault has developed in order to protect all other parts of the network and preserve supplies. In order to achieve this, the protection system requires a number of qualities the most fundamental of which are reliability and discrimination. Reliability ensures that the protection will operate when called upon to do so and discrimination ensures that only the faulty section of the network is disconnected from the system, enabling maximum continuity of supply to be maintained. The other qualities which protection requires to fulfil its duty are stability and appropriate operating times. The protection while taking account of system conditions shall remain stable and only operate for a fault within its zone. When required to operate, it shall disconnect the faulty section as speedily as possible.

## 4.1 Checking and Recording of Protection Asset and Settings Data

### 4.1.1 Recording of Schemes and Maintainable Assets

There is a requirement to hold a record of protection for every circuit. This will be at a level of detail which will allow Electricity North West Limited to record each scheme of protection applied to a given circuit or item of plant. The data required will be collected using the data amendment sheets which are part of the standard amendment pack as detailed in CP606 G18.

### 4.1.2 Recording of Settings

In order to provide a complete system for protection settings, from calculation and approval of settings, commissioning and maintenance and update of records throughout their lives a schedule of responsibility has been detailed below.

The responsibility for calculation of protection settings lies with the relevant planning section whether distribution, connections or grid and primary. All settings are required to be checked and approved before being issued to the commissioning engineer. The settings should be checked by someone not involved in their calculation. All settings calculations shall be issued to the Protection Systems section at protection.systems@enwl.co.uk for approval prior to issuing to Data Management and the commissioning engineer.

Where a substation is being newly built, refurbished or altered all settings once checked and approved shall be provided by the relevant planning section to the commissioning engineer. In order to reduce setting errors for modern relays the settings shall be provided electronically for downloading to the relay by the commissioning engineer. A settings sheet shall be prepared for the substation containing details of individual relays with an individual sheet per circuit. This sheet will be provided to Data Management as part of the pre-commissioning data required under CP606 G18. A copy of the approved settings calculations will be retained by the protection systems section and be held on a central database for future reference. Where special settings are required, e.g. for ALRS and VC schemes, the settings shall be obtained from System Development.

The commissioning engineer shall be responsible for implementing the settings on site, checking all protection for correct operation and ensuring the actual applied settings are correctly reflected in the settings sheets to be provided on site as well as the electronic relay files. Copies of the as commissioned settings sheets and the electronic relay files shall be provided to data management and will be maintained in a central database.

Where temporary settings are employed on site for any period longer than that required for switching these shall be plainly marked and clearly visible on site. This shall be done both at the relay and the settings sheet stating the circuit name, settings used, when applied, who applied them and why.

The relevant planning section shall review protection settings where any changes are made to network configuration. For any queries regarding the settings refer to the protection systems section for advice. Any alterations or changes shall follow the procedure described in this section be reflected on the settings sheet and in the office records. All proposed setting changes shall meet the requirements of this policy document.

## 4.2 Microprocessor Relays and Communications

The modern microprocessor based relays e.g. Alstom Micom, Reyrolle Argus, Siemens Siprotec etc. have been installed for a number of years on the Electricity North West Limited network. These relays incorporate communication links that can be used to access all relay data, via a laptop PC, either on site or remotely. Historically, in a few substations, the communications links have been wired to a single central communications point for accessing the relays. However, in the majority of substations this is not the case and access to a relay is via it's own individual communications port (front or rear). Where communications have been centralised on a switchboard the procedure for relay addresses outlined in Appendix A2 will have been followed. The procedure for naming of electronic setting files outlined in A5 shall be followed in all cases.

Electricity North West Limited are implementing the use of DNP3 communications from relays to the NMS RTU. This will carry significant cost savings in removing the hard wiring between the relay and the RTU. The DNP3 communications link will carry all alarms, analogues and controls between the CB and NMS. Where DNP3 communications is utilised the relays will be addressed as set out in Appendix E.

## 4.3 Grading Margin and Reset Times

The time interval between the operation of two adjacent relays is known as the grading margin and is dependent on several factors including circuit breaker interrupting time, relay and CT errors and a safety margin. With older electromechanical relays and oil circuit breakers the typical grading margin used is 0.4s to ensure discrimination. Where modern electronic relays and vacuum circuit breakers (i.e. GVRs) are in adjacent use on the network it is permissible to reduce the grading margin to 0.2s.

The older electromechanical type relays that utilise a mechanical disc have an inherent reset time depending on how far the disc has travelled under fault conditions. The reset time for a full trip is approximately 14 seconds. This reset effect has advantages for 'pecking' type faults where the relay may not have fully reset by the time the fault repeats itself and causes the disc to travel further each time eventually causing a trip. The modern electronic microprocessor based relays have a programmable reset time, which is a definite time for every pick up, regardless of fault current and duration. In order to provide a reasonable co-ordination with the discs of existing electromechanical relays and avoid instantaneous resetting for pecking faults, the majority of modern relays shall be set with a reset time of 2.5 seconds. The exceptions to this are those relays which necessarily require longer delays such as those involved in auto-reclose, delayed auto-reclose, auto-changeover schemes and standby earth fault relays.

## 4.4 Trip Relay Resetting

In general, across all the voltage levels trip relays shall be arranged to be self or electrically reset in order that telecontrol can be utilised to reconfigure and restore the system as quickly as possible. The exception to this is for main busbar protection operation which shall have hand reset trip relays only. This is because without any further supporting information from site it is not possible for the Control engineer to know the status of the switchgear. The use of hand reset ensures someone visiting site and this will confirm whether the fault that caused the busbar protection operation has damaged the switchgear and to what extent. In general, where self-resetting is applied it shall be carried out after approximately 8s. Where auto-reclose, delayed auto-reclose or auto-changeover schemes require different resetting times or regimes then these shall be applied as necessary to ensure correct operation of the scheme.

### 4.5 Protection Equipment

The protection equipment and ancillaries approved for use are detailed in Electricity Policy Document (EPD) 307.

Any new protection equipment proposed for use on the Electricity North West Limited network will have to be approved in accordance with EPD311 and CP311 – Approval of Equipment for use on Electricity North West Limited Network.

### 4.6 Quality of Supply (QoS) Protection Settings Project

A project to review protection settings on the distribution network has been instigated in order to improve Quality of Supply performance. Issues have been identified across the network with grading between network circuit breakers, reclosers and primary breakers causing more of the network to trip off than necessary and added delays in restoration of supply due to the confusion as to where the fault actually is on the network. Further, this leads to the possibility of the loss of further customers (on a backfeed circuit) due to FLISR closing a normally open point (NOP) on to a faulty section.

The QoS settings project is reviewing settings on more than 1500 distribution feeder circuits. Due to the amount of work involved in calculating and applying these settings some decisions have been agreed as to how both the calculation and application of settings shall be done so as not to cause unnecessary delay to the whole program.

#### 4.6.1 Calculation Assumptions:

Protection setting calculations are carried out as if the circuit was brand new and there were no existing settings. This is due to the fact that we have very few, if any, records of settings for GVRs and distribution network circuit breakers.

Where CT ratios are unknown, a range of settings will be calculated for different “expected” CT ratios. The actual ratio will be confirmed by the engineer who applies the settings.

When selecting settings for network devices (mainly GVRs), the $I^2t$ figure is calculated on the main line at the outgoing terminals of the protective device. Should this value exceed that permissible for the conductor involved, then a reduction in the GVR settings will be attempted to try and get within the permissible figure. If this is not possible, then this will be recorded as a known $I^2t$ issue and continue with the original settings. This will result in a list of known $I^2t$ issues which will be the subject of a further project for future action. No other $I^2t$ issues further down the circuit (e.g. on spur lines) are to be considered under this work.

Further, although policy (EPD321) states that the preferred settings for a GVR are 2 Inst trips followed by 2 IDMT, it does allow 3 Inst & 1 IDMT (or fewer trips as long as the first is Inst and the last is IDMT). Therefore, for the QoS project GVRs are set to 3 Inst and 1 IDMT trip (or 2 Inst & 1 IDMT) in an effort to keep the resulting $I^2t$ figure down.

Primary HV feeder settings can be increased without referral to the Protection Policy manager for approval, as long as such increases are within, or equal to, existing settings on other feeders at the same Primary. Any required increase which results in settings above those already existing on other feeders will still require approval from the Protection Policy manager.

SEF time settings can be increased to a maximum of 12 secs without reference to the Protection Policy manager.

### 4.6.2 Application of Settings

Under CP606 procedure S48 it is normal policy where protection settings are changed for planned work that these settings are then tested to prove the operation of the relay and the trip circuit. Due to the quantity of settings to be applied under the QoS program a separate procedure has been agreed that in most situations will not require an outage for application of a protection settings change. The QoS protection setting change procedure is attached in Appendix D.

# 5 132kV Protection

The term "plant" used in this policy description is reserved here for items such as transformers and reactors and is distinct from "feeders" which covers both underground and overhead line plain, teed, or transformer feeders.

## 5.1 Feeder Protection

All underground cable and overhead line circuits shall be fitted with main protection capable of being set to achieve full discrimination for 132kV phase and earth faults. Preference shall be given to the use of unit protection. Wholly underground circuits shall only be fitted with unit protection. Circuits that are mainly overhead and of suitable length where no appropriate communications circuit is available shall use distance protection. Distance protection shall use offset mho characteristics for phase fault coverage and may use the same or quadrilateral characteristics for earth fault coverage. If the relay offers provision to use a quadrilateral characteristic for phase fault coverage this may be used. For overhead line circuits consideration shall also be given to possible emergency running arrangements and temporary cross connection to other circuits. In these situations, distance protection is preferred and, in those circuits where unit protection is to be installed it may be prudent to install an alternative main protection using distance functionality. Main protection for transformer feeders also includes three pole directional overcurrent relays fitted on the lower voltage side of transformers. Due to the increase of generation on the network new directional relays shall be capable of being set to allow full reverse power through the relay but still operate for remote end faults. Generally, the main protection operating time for the majority of faults shall not exceed 200ms (the exception to this may be zone 2 on distance protection usually not exceeding 400ms).

Backup line protection shall comprise standard inverse time overcurrent and earth fault relays (as a minimum this will be 2 pole overcurrent and 1 pole earth fault). For each line, protection shall be fitted such that for all credible line faults, at each circuit end providing infeed to the fault there shall be a minimum of two measuring relay systems capable of detecting the fault and tripping the appropriate circuit breakers. An exception applies to circuit breakers on the lower voltage side of 132kV transformers, when one of the relay systems may be an intertrip receive relay, this itself not being a measuring relay. Fault clearance for lines shall be fully discriminative assuming no failure of measuring relay.

Intertripping shall not normally be provided on plain feeders, unless wound type voltage transformers are connected to the line. However, if intertripping is associated with plant connected to the feeder, then the line protection shall be connected so as to use the intertripping feature to provide an additional back up function.

## 5.2 Plant Protection

All items of plant shall be fitted with fast acting fully discriminative main unit protection schemes incorporating biased differential, restricted and balanced earth fault functionality to detect phase and earth faults.

For plant, fast fault clearance (and hence limitation of damage) may be totally reliant on one intertripping system. Intertripping shall not generally be duplicated but shall always be provided with comprehensive monitoring. The combination of a simultaneous plant fault and a co-incident intertripping failure is treated as an extremely small risk.

Whenever plant is connected via motorised disconnectors and intertripping is used, the plant's main protection trip relay shall be arranged to cause automatic opening of the disconnector. If a switching disconnector having on load interrupters is used, a three phase overcurrent check relay shall be arranged to prevent automatic opening if the current rating of the disconnector is exceeded. If the disconnector is an air break off load type then no overcurrent or voltage checks shall be made, and the auto opening will provide some degree of backup to an intertripping failure.

Backup protection for plant shall include standard inverse time phase and earth fault relays and, as appropriate, other devices such as Buchholz, pressure relief, oil/winding temperature relays and arcing horns. The Buchholz and winding temperature relays are usually configured to be two stage with an initial alarm and then trip setting. Settings for winding temperature contacts for pumps, fans, alarms and trips are contained in CP382 and ES324. Settings for arc gaps are contained within ES324.

### 5.3 Busbar Protection

All main busbars at major multi-switch GSP or generation substations shall be fitted with fast acting fully discriminative main and check unit protection to detect phase and earth faults. Such schemes shall include duplicate zones on each section to provide main and check functionality. The operation of the protection shall prevent any automatic reclosing onto the faulted busbar section.

Other busbars shall normally be protected by suitably overlapped zones of line protection. For outdoor busbars, it is acceptable for delayed automatic reclosing to proceed from the line protection and possibly reclose onto these busbars.

Backup protection for busbars shall be by means of the associated plant and line protection backup relays, supplemented by standard inverse time overcurrent and earth fault relays fitted to all bus-section and bus-coupler circuits on main busbars.

When the busbar protection supervision relay detects a malfunction in the busbar protection scheme it shall inhibit the busbar protection from operating.

### 5.4 Intertripping

Intertripping shall be fitted to all circuits associated with plant supplied via remote circuit breakers. Duplication of the intertripping system is not required, but it shall be fully monitored to give immediate warning of equipment or pilot circuit failure.

Whenever intertripping is fitted, both the plant protection and any associated line protection shall utilise it to open remote circuit breakers.

### 5.5 Delayed Automatic Reclosing

All lines containing sections of overhead line shall normally be fitted with delayed automatic reclosing (DAR) with a minimum dead time of 10s. Cables connecting between overhead line sections along the route shall normally be treated as if part of the overhead system and will be subjected to reclosing if they fault. DAR will not be enabled from the operation of feeder unit protection that protects a wholly underground circuit. Where circuits include cable sections, including cable closures in excess of 1000m, a unit protection scheme shall normally be provided to that cable section to operate solely as a blocking scheme to prevent operation of the DAR. For all cables of such circuits, special protection arrangements will be necessary to prevent reclosing for faults on these if they are routed such that a danger to personnel or the public is envisaged, for example, cables in tunnels. DAR will be initiated only from the normal circuit main protection. For circuits protected by distance protection this will include both zone 1 and zone 2 operation. DAR will not be initiated from operation of backup protection, operation of low frequency protection or zone 3 distance protection.

For circuits with plant connected, DAR shall be initiated from the line protection relay and an intertrip receive signal but is subsequently inhibited if there is a positive indication that any faulty plant has not been cleared from the circuit.

### 5.6 Automatic Isolation

For all circuits associated with teed or banked plant, a fault on any item of plant shall cause automatic isolation of that plant and subsequent automatic restoration of the healthy plant.

## 6 33kV Protection

### 6.1 Feeder Protection

All underground or overhead feeder circuits shall have fast acting, fully discriminative unit protection to detect phase and earth faults as the main protection. Feeders that incorporate mainly overhead line and have no associated pilot circuits will use distance protection for main protection, utilising an offset mho characteristic for phase and earth faults. Generally, the main protection operating time for the majority of faults shall not exceed 200ms (the exception to this may be zone 2 clearance on distance protection usually not exceeding 400ms). Balanced earth fault shall be fitted to the primary or feeder end of the transformer feeder.

Some of the traditional unit protection relays (MHOA and MHOB Translay) have been made obsolete by manufacturers. These relays worked over copper pilots (cored or paired) and either did not provide any supervision of the pilots or required separate supervision relays. There are other traditional two ended unit schemes that work over copper but these also require the addition of other relays to provide supervision and guard functionality.

Modern unit protection relays use digital signalling and may require converters (fibre to copper) to be able to work over copper pilots, but this usually has limitations on the pilot distance. Any new unit protection scheme to be fitted to the network shall incorporate pilot supervision and the ability to reduce backup OCEF time multiplier settings for loss of pilots. Typically, time multipliers shall be reduced from 0.4 to 0.25 (or a similar ratio where this is not the setting applied) in this situation taking into account grading with downstream protection. A modern two ended unit protection relay that works over copper pilots (or fibre), incorporates pilot supervision, backup OCEF and guard OC, has been tested and proved on some very poor pilot (mixed cored and paired) network over a distance of 16km, and is approved for use on the network. Where three (or more) ended unit protection is used the preference is always to use fibre communications to prevent any limitations on the scheme. Care is required if the unit protection is connected to ENWL's multiplexer network and checks shall be made on the multiplexer communication path to check that it is suitable for unit protection and meets manufacturer requirements for latency, including redundant path(s). Use of copper pilots with fibre to copper converters has been trialled previously with limited success and not currently used. Mar 23

Backup protection for underground or overhead feeder circuits shall be standard inverse time overcurrent and earth fault relays (minimum 2 pole overcurrent and 1 pole earth fault). Transformer feeders that are overhead line fed, shall use neutral voltage displacement to detect a feeder fault backfed through the transformer. As there is usually no local 33kV circuit breaker on transformer feeders, the voltage signal for the neutral voltage displacement is derived from capacitor cones fitted into the 33kV bushings on the primary transformer, with typical values of 60pF or 90pF used. The neutral voltage displacement shall be a two stage scheme with the first stage arranged to trip the local 11kV circuit breaker after approx 12s, if the fault persists then after a short time delay of 500ms the second stage shall trip/intertrip the remote 33kV circuit breaker. Where there are no pilots then a fault thrower can be used to initiate tripping of the remote end.

Standby earth fault protection provides protection to the NER and final feeder protection in the event of a 'stuck breaker' situation. The standby earth fault protection shall use an inverse time characteristic (usually LTI) to ensure appropriate tripping times and discrimination and shall be arranged to be a 2 stage scheme at BSPs. The standby earth fault protection on each of the 33kV incomers shall have a first stage that trips the local 33kV breaker. After a further short time delay the second stage shall trip/intertrip the remote 132kV circuit breaker. Mar 23

## 6.2 Plant Protection

All items of plant shall be fitted with fast acting fully discriminative main unit protection schemes incorporating balanced and restricted earth fault functionality to detect earth faults in both primary and secondary windings and high set overcurrent (HSOC) fault protection to detect 33kV phase faults.

For plant, fast fault clearance may be totally reliant on an intertripping system. The combination of a simultaneous plant fault and a co-incident intertripping failure is treated as an extremely small risk. Where intertripping is not available other means shall be utilised to ensure remote tripping. A fault thrower can be used to ensure remote tripping for transformer protection operation.

Backup protection for plant shall be standard inverse time 3 pole phase and 1 pole earth fault protection. Restricted earth fault protection shall be fitted to protect the majority of the secondary winding of the transformer.

Transformer protection shall also include Buchholz alarm/trip, pressure relief alarms and winding temperature relays.

## 6.3 Busbar Protection

All main busbars at 33kV substations shall be protected by fast acting fully discriminative protection incorporating main and check systems. The standard scheme is for metal enclosed switchgear for which only earth fault protection is required. There shall be one main discriminating system for each section of busbars. The check system shall preferably be the frame leakage type covering the whole busbar with no requirement to discriminate between zones. The operation of the protection shall prevent any automatic reclosing onto the faulted busbar section. Should the design of the switchgear allow phase faults then a phase fault protection scheme shall also be required.

Backup protection for busbars shall be by means of the associated plant and line protection backup relays.

## 6.4 Auto-Reclosing

Where a circuit contains any section of overhead line then the feeding circuit breaker may be fitted with auto-reclose. Where intertrip is available then the auto-reclose shall be inhibited for transformer or busbar protection trips. Where no intertrip is available, a fault thrower being used at the remote end of the feeder, a single reclose is permitted after which the protection is locked out. The auto-reclose protection shall be in accordance with EPD321 – Policy for Automatic Reclosing of Overhead Lines.

### 6.5 Intertripping

Intertripping shall, where possible, be fitted to all teed or banked plant supplied via a remote circuit breaker. Where pilot circuits are not available the use of a fault thrower shall be instigated by the local transformer protection in order to trip the remote end. Where motorised isolators or disconnectors are fitted these shall be arranged to automatically disconnect plant in the event of a fault and aid restoration of the healthy circuit. All intertripping used on new or replacement circuits will incorporate communication circuit supervision and alarm for failure of the circuit.

## 7 11/6.6kV Protection

### 7.1 Feeder Protection

All underground or overhead feeders shall have standard inverse time over current and earth fault (minimum 2 pole overcurrent and 1 pole earth fault) relays for detection of phase and earth faults. In order to achieve relay discrimination on the network, a normal clearance time of 1s for an 11/6.6kV fault close to a primary substation shall be used. Where small cable sizes impose the need for faster clearance times, this can often be achieved by using a high-set overcurrent relay. Where a customer requires an automatic firm supply then feeder protection may be by means of unit or directional protection, generally at the customer's expense. The comments regarding unit protection and the communications circuit requirements in section 6 apply.

Where the feeder contains any section of overhead line greater than 500m, (not aggregate), then sensitive earth fault protection shall also be fitted. SEF protection is used to detect high impedance faults which result in lower currents which cannot be detected by conventional earth fault protection, taking a longer time to trip. If the ground mounted circuit breaker is fitted with auto-reclosing facilities (see section 7.4) it is allowable to carry out a single shot reclose following operation of the sensitive earth fault relay. SEF shall also normally be applied at GVRs downstream of the primary feeder and set to allow one reclose following an SEF trip. Discrimination shall be achieved by time grading with a 2s grading margin between zones. The requirements in this policy take precedence over those in the auto-reclosing policy EPD321. For new and replacement circuits SEF functionality will be incorporated in the feeder protection relay to be utilised where required.

Backup protection for feeder circuits shall be standard inverse time 3 pole overcurrent relays and long time inverse standby earth fault relays fitted on feeding transformers at the primary substation. Where a modern busbar blocking scheme as described in 7.3 below is not fitted then a 3 stage standby earth fault scheme shall be incorporated. The first stage shall trip the bus section circuit breaker and after a short time delay the second stage shall trip the relevant incomer circuit breaker. The third stage, after a further time delay shall trip/intertrip the remote 33kV circuit breaker. It should be noted that where there is a closed ring across the two sections of the board then the Section A end of the ring will be opened at the same time as the bus section. This may prevent the healthy side of the board feeding into the section with the fault on or may cause loss of the closed ring which can be restored by telecontrol. Where a modern 3 stage busbar blocking scheme is provided then the normal 2 stage standby earth fault scheme will be provided.

Where unit protection is fitted for feeder protection this shall be maintained or extended where economic to do so during replacement or alteration to the system.

Backup protection shall not be fitted in distribution substations.

### 7.2 Plant Protection

The secondary side of the primary transformers shall normally be protected with restricted earth fault protection and directional overcurrent looking back up into the transformer. For larger transformers above 23MVA the difference between load current and fault current is minimal and it may not be possible to provide a protection setting that will ensure a suitable trip time. In these situations it will be necessary to use a voltage controlled overcurrent relay which reduces overcurrent settings when the voltage reduces under a fault situation. If communications exist between all the overcurrent relays on a busbar, a logic based blocking system could be used to offer the same protection.

The following shall apply regarding the application of overcurrent protection on the MV side of Primary Transformers:

- In instances where bus zone blocking exists, the directional overcurrent protection for faults on the 33kV incomers shall be set to IDMT characteristic. Where relay limitations prevent the selection of 11/6.6kV IDMT back up overcurrent, a definite time characteristic shall be selected to protect for transformer overloads.

- Where no bus zone blocking scheme exists, the scheme shall incorporate directional overcurrent to protect for faults on the 33kV incomers, and 11/6.6kV back up IDMT overcurrent protection. The preferred characteristic of the directional overcurrent shall be IDMT, however where this cannot be achieved due to relay limitations, a definite time characteristic shall be selected.

- The transformer itself shall have buchholz, winding temperature and pressure relief protection fitted. These are generally arranged as two stage devices set to alarm and then initiate a trip except for the pressure relief which shall be an alarm only.

All plant at the distribution network level of 11and 6.6 kV shall be protected in accordance with CP331 and comply with the design requirements of EPD282.

### 7.3 Busbar Protection

Busbar protection is not normally applied at 11/6.6kV. However, the advent of microprocessor based relays has allowed the plant and feeder relays to be utilised in a 'blocking' scheme to form a basic busbar protection scheme. This not only provides a form of busbar protection but can be combined to give backup for a stuck breaker situation.

There are two versions of the blocking scheme, as described in Appendix C, and both are arranged to be a 3 stage scheme in order to minimise the loss of supplies. In the older busbar blocking scheme the first stage trips the bus section circuit breaker and by use of a directional element in the bus section the appropriate circuit breaker feeding any closed ring. In the current version of the busbar blocking scheme there is no relay in the bus section and the first stage trips the bus section circuit breaker and the Section A feeder breaker for any closed rings. The second stage after a short time delay trips the relevant incomer circuit breaker. The third stage after another short delay shall trip/intertrip the remote end 33kV circuit breaker. All new and replacement primary switchboards will incorporate the modern version of the busbar blocking scheme.

Where a busbar protection scheme is fitted then a single stage standby earth fault scheme shall be incorporated.

### 7.4 Auto-Reclosing

HV circuits may contain numerous nested automatic fuses and circuit breakers sometimes located in the main circuit; for example mid point circuit breakers or GVRs. Due to the difficulties inherent in obtaining reliable protection grading for all fault scenarios and the potential for failure of remote non monitored tripping batteries, it is not always possible to guarantee correct discrimination under fault conditions between automatic devices. The consequence of non discrimination will usually be the operation of the primary substation feeder circuit breaker, and where the circuit contains a section of overhead line this can occur for transient faults. To mitigate against this risk, where a circuit contains any section of overhead line or connections then the feeding circuit breaker shall be fitted with auto-reclose. It is permissible to reclose following a trip from either instantaneous, IDMT or SEF protection (see section 7.1 for SEF reclose requirements). On new or replacement circuits the auto-reclose functionality will be provided by the Telecontrol Delayed Auto Reclose (TDAR) algorithm within the FLISR application. No separate DAR relays will be fitted to any new or replacement circuits. EPD321 contains the detailed information on settings for auto reclose, however, the principles outlined in section 7 of EPD350 take priority over EPD321. Where auto-reclosing is applied to a circuit either through local relays or via TDAR/FLISR then the facility for switching to a Live Line working mode shall be incorporated locally. Switching to Live Line working will cause all protection (overcurrent, earth fault and sensitive earth fault) to use an instantaneous characteristic with no time delay and no reclosing once tripped (DAR switched out). Mar 23

In the context of this policy statement a circuit is defined as encompassing all network assets, cables and overhead lines from the outgoing 11/6.6kV primary substation circuit breaker to the normal open points at the extremities of the feeder. The feeding circuit breaker is defined as the outgoing 11/6.6kv primary substation circuit breaker energising the circuit. An ‘overhead line’ is defined as a section of overhead conductor of at least one span in length.

### 7.5 Intertripping

Intertripping is generally only used on the 11/6.6kV side of the primary transformer to remote trip the 33kV end, not on the outgoing 11/6.6kV feeders. All intertripping used on new or replacement circuits will incorporate supervision of the communication circuit and alarm for failure of the circuit. The use of pilot wires will generally be restricted to unit protection, where fitted at 11/6.6kV.

# 8 Documents Referenced

| DOCUMENTS REFERENCED | |
|---|---|
| **EPD282** | Distribution System Design 11/6.6kV Network |
| **EPD307** | Equipment Approved for Use on Electricity North West Network |
| **EPD311** | Approval of Equipment for use on Electricity North West Network |
| **EPD321** | Policy for Automatic Reclosing of Overhead Lines |
| **CP311** | Approval of Equipment for use on Electricity North West Limited Network |
| **CP331** | Protection of LV Overhead and Underground Distributors and HV Overhead Networks |
| **CP338** | Protection Settings for the 132kV System |
| **CP373** | Protection Settings for 33kV and 11/6.6kV Systems |
| **CP606** | Operations Manual, Procedure G 18 - System Amendment Procedure |
| **CP382** | Transformer Ratings |
| **ES324** | 132kV/Lower Voltage Transformers and Earthing/Auxiliary Transformers |
| **ES337** | Specification for 19 inch Rack Control and Relay Panels for use in BSP and Primary Substations |

# 9 Keywords

Protection; Relay; Settings; Busbar; Feeder; Plant; Auto-Reclose

# Appendix A – Policy for Communications Addressing and Storing of Settings on Modern Numeric Relays

## A1 Background

Modern microprocessor controlled digital relays have been installed on the Electricity North West Limited network for over fifteen years. Depending on the age and manufacturer they come with a variety of different interfaces and differing communication types. They are most easily programmed to a user's requirements with a portable laptop pc, using the appropriate manufacturer's software and communications interface equipment. The majority of different relay types used within Electricity North West Limited, their front panel interfaces, communication types and interfaces are all listed in Table A1 below.

**Table A1 – Relay Types and their Communications Interfaces**

| MANUFACTURER | RELAY TYPE | COMMS TYPE | INTERFACE EQUIPMENT | COMMS CONNECTION | SOFTWARE USED |
|---|---|---|---|---|---|
| Areva (ex-Alstom) | K series | Twisted pair | KITZ box* | Rear of relay | Micom S1 or PAS&T |
| | Micom | Twisted pair or fibre optic | Protocol interface or serial lead | Rear of relay or RS232 on front | Micom S1 Agile |
| Siemens | Siprotec | Twisted pair or fibre optic | Protocol interface or serial lead | Various on rear of relay inc. RS232<br><br>RS232 on front | DIGSI 4 |
| Siemens Reyrolle | Argus | Fibre optic | Fibre to electrical converter | Rear of relay | Reydisp Evolution |
| | Argus C/M | USB / RS485 | USB lead | USB front / RS485 rear | Reydisp Evolution |
| | Delta, Ohmega, Microtapp | Fibre optic | Fibre to electrical converter or serial lead | Rear of relay or RS232 on front | Reydisp Evolution |

* - The KITZ interface box is an interface between the RS232 port of the computer and the K-bus communications connections on the protection relay.

This procedure describes the standard approach to be adopted to enable settings to be applied whilst also ensuring that a proper protection setting record system is maintained.

## A2 Historical Communications and Addressing of Relays

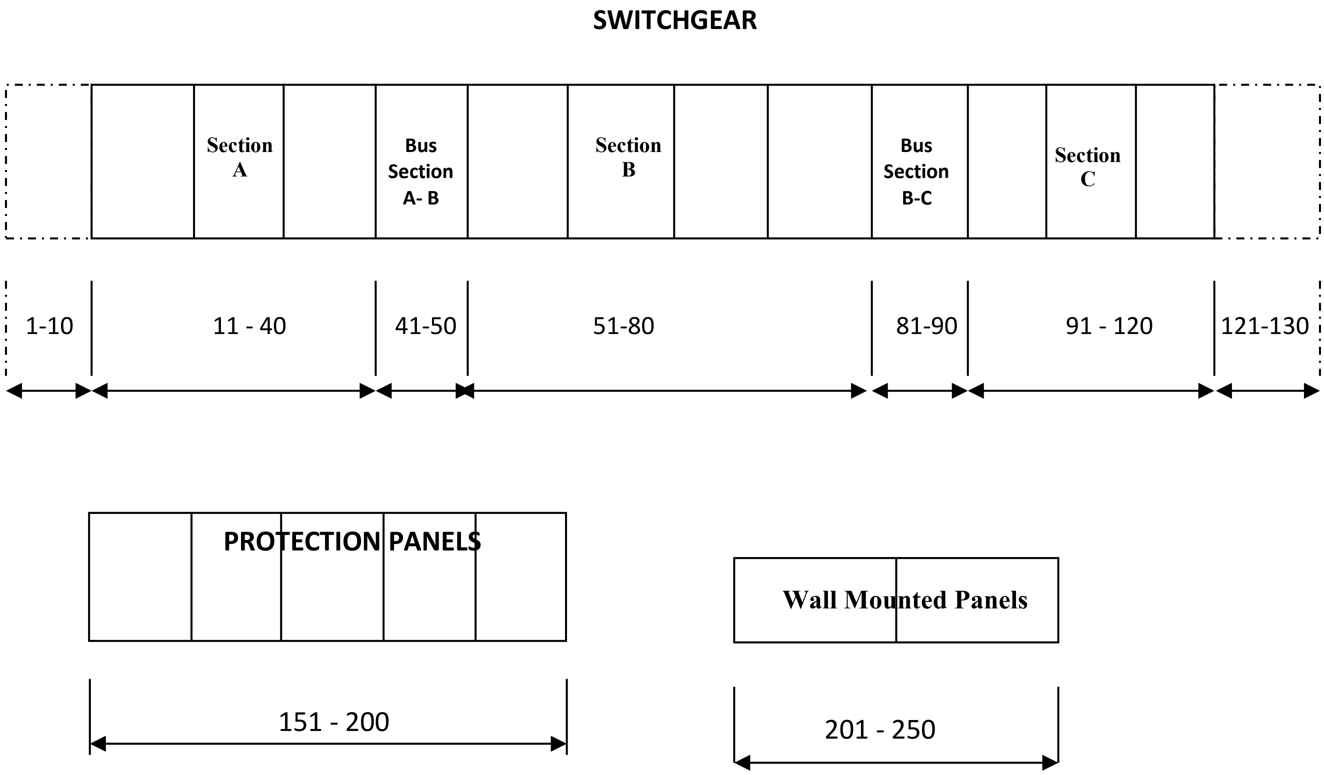
It is possible to connect multiple relays on a single communications circuit the limitations being imposed by the type of communications and the manufacturer's equipment involved eg it is possible to have a maximum of 32 K relays looped together on a twisted pair of wires (known as the "K-Bus") connected to a single KITZ interface box . In order to do this each relay must have its own address, and the method of achieving this is different for the various relays. For K relays the address is any number between 1 and 254. The factory default setting is 255, being a special address that does not allow the relay to output information to the computer. The commissioning engineer must manually insert the factory default password (AAAA) and select an address before settings can be applied via the computer. For Siemens Reyrolle relays the address must also be configured by the commissioning engineer through the communications menu from the front of the relay and is a number between 1 and 254.

The preferred arrangement within a substation shall be for all relays communications circuits to be connected up and to be able to access the communications from one central point. At this stage the preference is that the communications hub or interface point is physically located in the bus section relay and control panel. In order to limit any effect that problems with communications circuits may cause there shall be separate communications circuits for each section of switchboard and also for any additional relays mounted separately in remote panels or wall boxes. The interface at the central point shall be via a serial cable link between the laptop and communications hub. The central communications hub shall also have the facility for additional communications circuits to be added so that future links into telecontrol outstations can be accommodated.

At this stage it has been decided not to add the capability to remotely interrogate the relays via the addition of modems to the communications hub.

The use of common communications circuits linking all relays in the substation means that relays shall have individual addresses. Where the commissioning engineer sets the address manually on the relay then the following procedure, as illustrated in Fig A1, must be used. Fig A1 shows a typical physical layout of a switchboard, separate protection panels and wall mounted panels including the dotted lines for extensions to the switchboard. Certain blocks of relay addresses have been allocated to the various sections of the switchboard and panels as shown in Fig A1. Within each section viewing the switchgear or panels from the front then the relay addressing should start from the top left and work towards the bottom right. The illustration below is typical of a 33kV substation however, in the case of 132kV substations it is likely that there will be no protection on the switchgear at all. In that situation it is acceptable to use the addresses allocated to the switchgear below for the relays on the protection panels. A small adhesive label showing the chosen address shall be fixed to each relay so as to be easily visible. (It shall not be fixed to the removable transparent cover!)

**Figure A1 – Addressing of Relays in a Substation**




## A3 Relay and Circuit Identification

In addition to the relay address, each modern relay can be programmed with a system description or identifier, usually a 16 character limit. Some of the relays (K-relays) also include for a 16 character plant reference as well.

The system description or identifier shall consist of the circuit name and protection function i.e. MOOR CLOSE OCEF or HARPRHY T12 SBEF. As can be seen from the example it may be necessary to remove letters to fit the description in the space available, this is acceptable as long as it is still understandable.

Where available on relays the plant reference shall consist of the plant reference of all local circuit breakers tripped by the relay (e.g. 4SW02). If more than one circuit breaker is tripped, all references shall be included. If three circuit breakers are tripped, all plant references could be included if no spaces are used between the individual references.

## A4 Standard Configuration

The modern microprocessor based numeric relays leave the manufacturer's factory pre-programmed with default settings. It is necessary for a user to change these to their particular requirements.

A series of standard configuration files has been developed for most standard applications at 11 and 33kV (132kV applications are not seen as standard). These take the form of standard electronic setting files and will be held in the electronic library under Equipment Information/Protection/Standard Setting Files. Each standard configuration file will be matched to standard diagrams and a full description will be available to familiarise relay setting engineers and commissioning engineers. The relay settings produced by the settings engineer shall be used to modify the standard configuration files and shall include current and time settings, CT ratios, allocation of relay functions to the output relay contacts and allocation of digital inputs. The appropriate design section setting engineer shall provide the complete setting file on disk to the commissioning engineer as well as providing an electronic version of the standard substation protection setting sheet.

The commissioning engineer shall:

(a) Load into a relay the specific settings file supplied by the setting engineer

(b) Confirm that all settings match the required values

(c) Save the relay settings to a file either on the hard drive or floppy

(d) Obtain a hard copy printout of the settings as soon as practicable

(e) Update the substation setting sheet with the standard settings and relay details for each circuit

(f) Return a copy of the updated substation setting sheet and all the individual electronic relay settings files to the settings engineer.

The design section settings engineer shall then update the central settings database with this information and attach all the electronic setting files to the appropriate circuit. The commissioning engineer shall leave a hard copy of the overall substation settings sheet on site and also a hard copy of the individual settings files for each relay.

The approach outlined above, whereby a hard copy is produced from each individual relay, ensures that the relay type and serial number is automatically recorded. If portable printers are provided for the commissioning engineers, the hard copies could be produced on site. On site records of relay settings shall be based on the format produced by the settings engineer, but a copy of the printout of (4) above shall be retained on site. The disadvantage of the hard copy printout is that a lot of detail is present. This detail is important to the commissioning engineer because it contains all the relay configuration in addition to the current and time settings.

## A5 Naming of Configuration Files

The filename for the relay configuration files shall be in a standard format so that the site, asset being protected and relay can easily be identified.

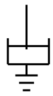
The following format shall be used -

Substation Number-Voltage-MAMS Asset Number-Relay Name-Relay Number-Group-Revision X .extension

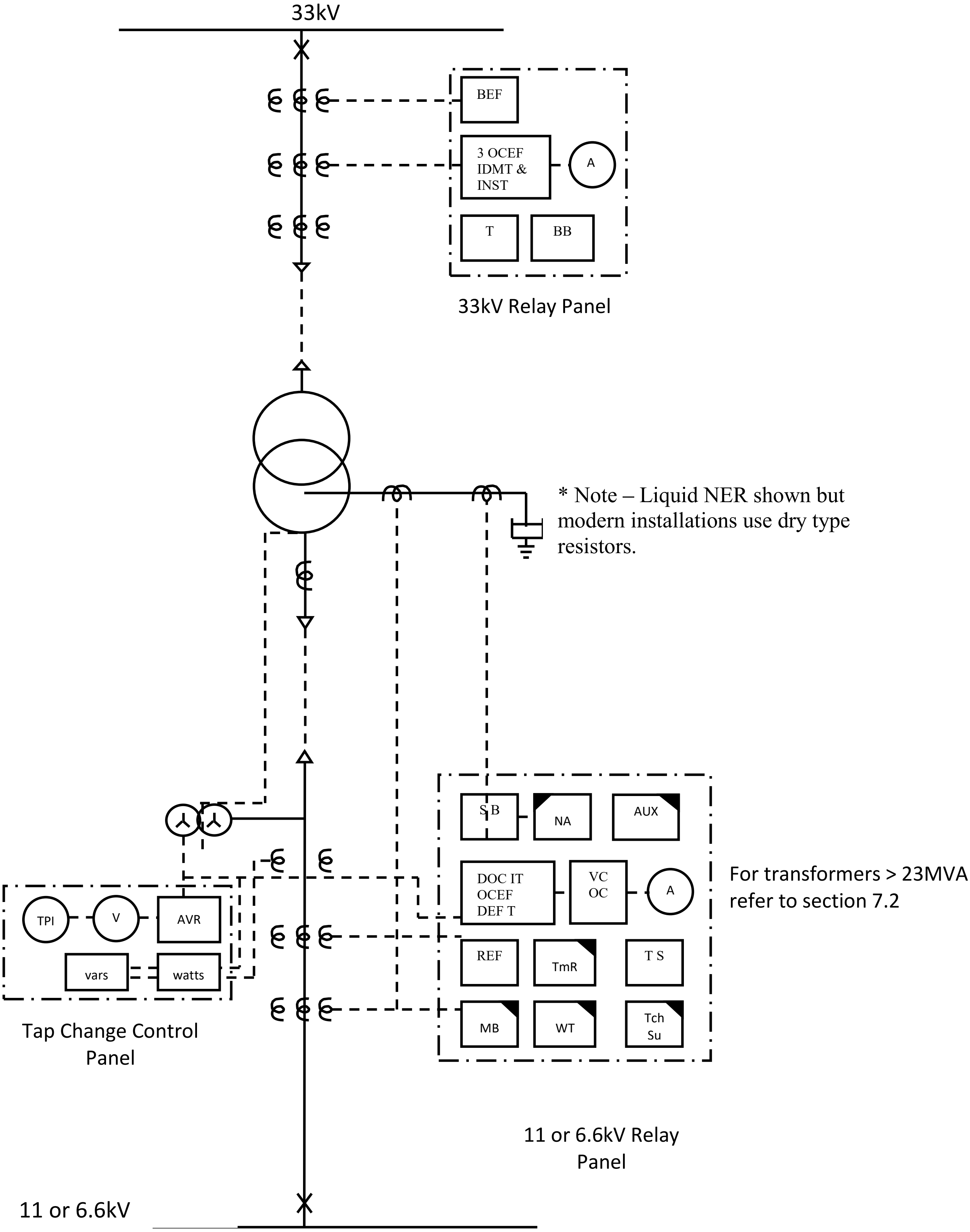
| | |
|---|---|
| **Substation Number** | 6 digit substation number |
| **Voltage** | 3=6.6kV<br>4=11kV<br>5=33kV<br>6=132kV<br>7=25kV |
| **MAMS Asset Number** | Always starts AP for protection.<br>Followed by 2 characters for asset type –<br>▪ TX-Transformer<br>▪ SW-Switch<br>▪ BB-Busbar<br>Followed by the number. Starts at 01 (for Switches 01 will usually be spare for new boards).<br>Example APTX01 or APSW04 |
| **Relay Name** | Examples - Argus 1, Argus 2, Delta, P142, P521 etc. |
| **Relay Number** | 1 if only one relay of that type in the panel or if relay is main protection, for example HSOC.<br>2 for back up protection. |
| **Group** | GRP followed by A for all or number to reflect group, 1 for group 1 etc.<br>For Micom relays this will be A as all the groups are contained in one file. For Reyrolle relays each group is contained in a separate file. |
| **Revision Number** | Starts at A. To be revised every time set file is changed. |
| **.Extension** | Examples .rsf2, .set or .psl |

The filename is not to be confused with the relay address (or identifier). Relays shall be numbered in accordance with section A2 of this EPD

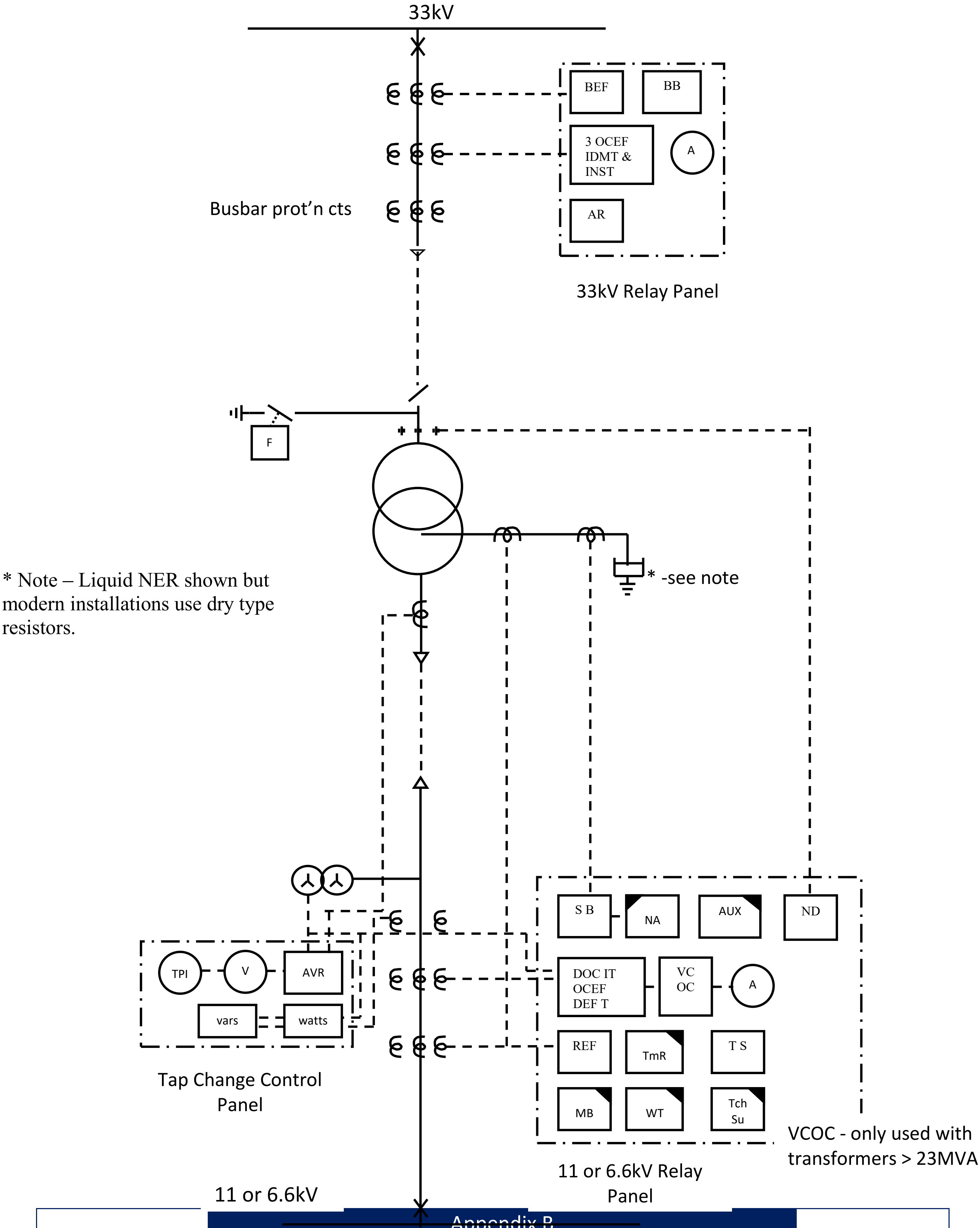
# Appendix B – Explanation of Symbols for Standard Protection Key Diagrams

| Symbol | Meaning |
|---|---|
| 3 OC | Three pole overcurrent relay (instantaneous) |
| 3 OC IT | Three pole overcurrent relay (inverse definite minimum time) |
|  | Alarm flag relay |
|  | Trip flag relay |
| REF | Restricted Earth Fault |
| S B | Standby Earth Fault |
| T | Trip Relay Electrical Reset |
| NA | Neutral Current Alarm |
| MB | Main Bucholz trip |
| WT | Winding Temperature Trip |
| Tch Su | Tap Change Surge Trip |
| AR | Auto-reclose |
| 3 DOC | 3 pole directional overcurrent (idmt) |
|  | Capacitor Bushing |
| DEF T | Definite Time |
| BB | Busbar Protection Auxiliary Relay |
|  | Liquid Neutral Earthing Resistor |
|  | Current transformer |
| AVR | Automatic Voltage Regulating Relay |
| BEF | Balanced Earth Fault |
| TPI | Tap Position Indicator |
| A | Ammeter |
| V | Voltmeter |
| VC OC | Voltage Controlled Overcurrent |
| ND | Neutral Voltage Displacement |
| TmR | Timer with trip |
| AUX | Auxiliary relay with trip |
| INT | Intertripping Relay |
| 3 OCEF | 3 pole overcurrent and earth fault (instantaneous) |

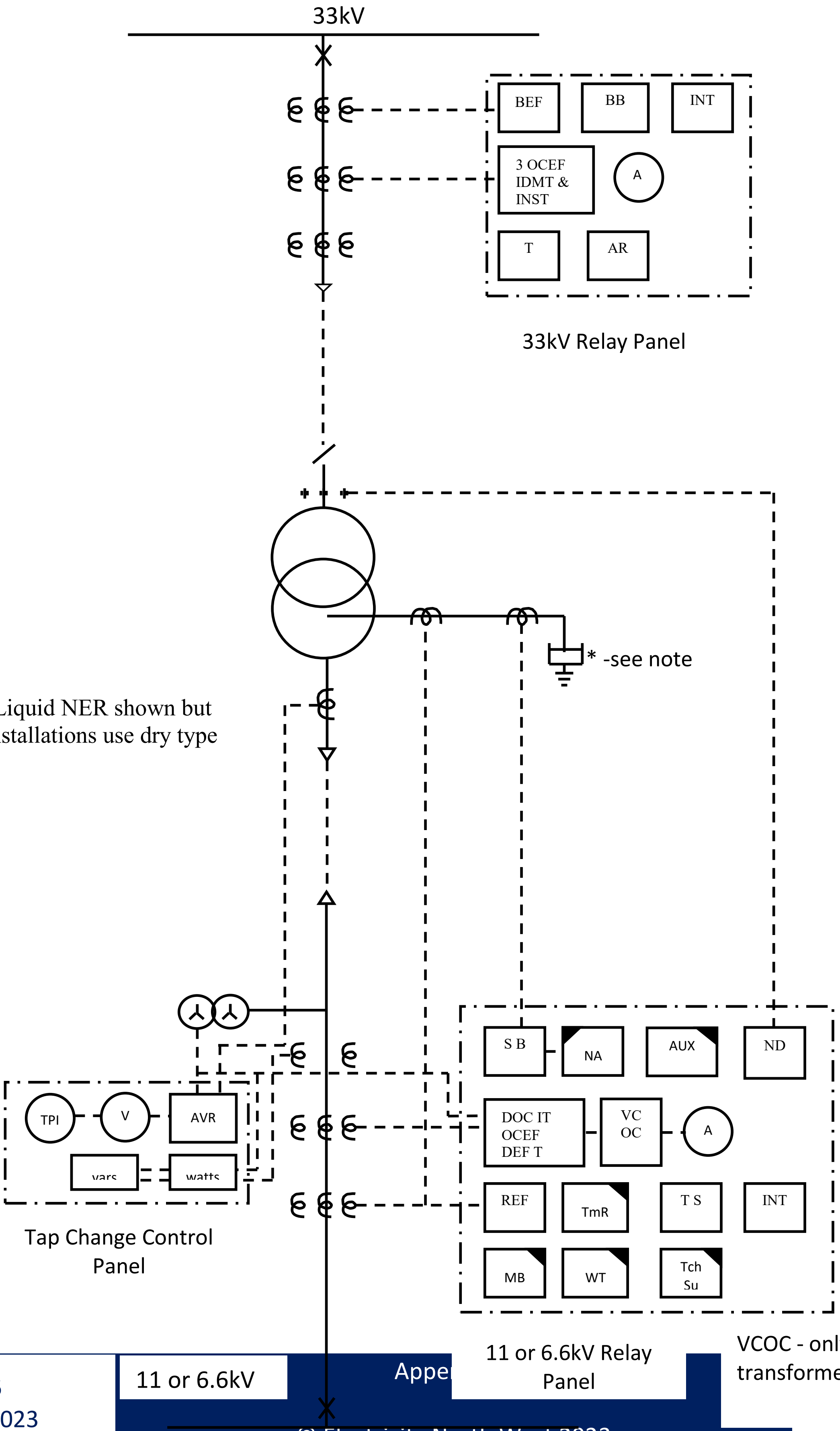
**Key Diagram for 33/11 or 6.6kV Transformer with HV and LV Adjacent – Functional Requirements**



**Key Diagram for 33/11 or 6.6kV Transformer HV Overhead Line Without Pilots**



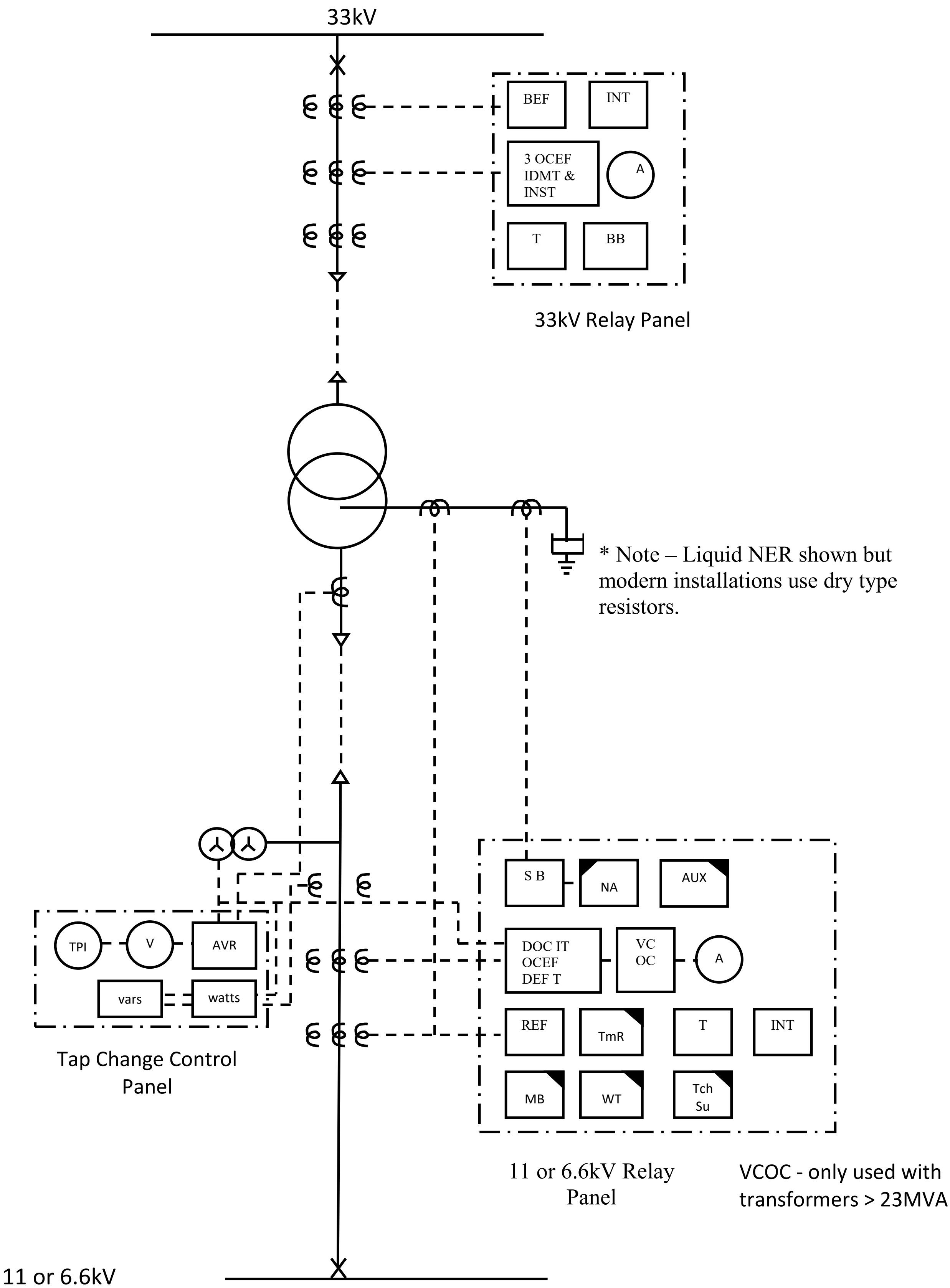
**Key Diagram for 33/11 or 6.6kV Feeder Transformer HV Overhead Line With Pilots**




* Note – Liquid NER shown but modern installations use dry type resistors.

VCOC - only used with transformers > 23MVA

**Key Diagram for 33/11 or 6.6kV Feeder Transformer with Underground Cable and Pilots**



# Appendix C – Busbar Blocking and CB Fail Scheme

## C1 Protection Scheme Description

The standard primary substation arrangement is shown in the attached diagram C1. Each of the outgoing feeders shall have a main protection relay to cover overcurrent and earth faults using standard IDMT curves.

The incomers have directional overcurrent protection, standby earth fault and also use high set elements as part of the busbar blocking scheme. The directional overcurrent protection is looking back up into the transformer and 33kV feeder and uses standard IDMT curves. The standby earth fault protection is fed from a ct in the transformer neutral and uses a LTI IDMT curve. The transformer secondary side and the tails are covered by restricted earth fault protection.

The relay shown in the bus section is shown with a dashed line as it has been used in older versions of the busbar blocking scheme. The modern version of the busbar blocking scheme does not use a relay in the bus section and where there are closed rings always opens the Section A feeder breaker (therefore closed ring trip links are fitted only on the section A closed ring CB). The older blocking scheme used the high set elements of a bi-directional overcurrent and earth fault relay as it was only there as part of the busbar blocking and circuit breaker fail scheme. The directional elements were used to allow the busbar blocking scheme to operate the relevant closed ring feeder breaker on the faulted section only (therefore closed ring trip links are required in each CB associated with closed ring).

The directional elements are polarised for fault current flowing from section A to section B trip the bus section and any closed ring CB(s) on section B. The directional elements are polarised for fault current flowing from section B to section A trip the bus section and any closed ring CB(s) on section A.

Where modern relays are working in schemes such as this that have the ability to trip other CBs then an appropriate warning label shall be fitted. This label is to remind the operator that any testing of the relay may cause tripping of other CBs and appropriate trip/isolation links need to be removed.

## C2 Fault Scenarios

### C2.1 Outgoing Feeder Phase or Earth Fault

A phase or earth fault on an outgoing feeder, as shown by F1 on the diagram, will cause the feeder IDMT relay to pickup. The starter element of the feeder relay initiates a blocking signal (via an output relay) to both of the incomers and the bus section. The blocking signal inhibits the operation of the high set elements on the incomers and bus section.

When the feeder relay operates it sends a trip signal to the feeder breaker and at the same time starts a CB fail timer, usually set to 300ms. If the breaker does not open correctly within that time then the blocking signal to the incomers and bus section is removed (via an output relay operated from the CB fail timer). The high set elements can then see the fault and the timings of the incomer and bus section relays are graded. This ensures the relay on the bus section trips the bus section CB and the closed ring CB on section A first (for both the older and the current blocking scheme). This will leave only the incomer on the faulted section of the board still seeing the fault and this will trip. This method means that only half of the board is lost for a stuck breaker on an outgoing feeder.

### C2.2 Genuine Busbar Phase Fault

For a genuine busbar phase fault, as shown by F2 on the diagram, none of the feeder relays will pickup and hence there will be no blocking signal. The directional overcurrent protection on the incomers is looking in the other direction and will not pickup. Therefore on the older scheme only the bus section and incomer high set elements will see the fault and time out accordingly, the bus section relay operates first tripping the bus section and the closed ring CB on section B (200ms) and then the appropriate incomer relay will operate tripping the transformer CB (500ms). Again this should ensure that only the half of the board with the busbar fault on is lost. On the current scheme the incomer high set elements operate and trip the bus section first as well as the closed ring CB on Section A, then the appropriate incomer CB will operate tripping the transformer. In this situation only half the board is lost but also supplies to the closed ring will be lost which can be restored by control.

### C2.3 Genuine Busbar Earth Fault

For a genuine busbar earth fault, as shown by F2 on the diagram, none of the feeder relays will pickup and hence there will be no blocking signal. The standby earth fault element will see the fault and pickup but it is working on a LTI curve and will take several seconds before any operation. As with a phase fault on the older scheme the bus section and incomer high set elements will also see the fault and time out accordingly, the bus section relay operates first tripping the bus section and the closed ring CB on section B (200ms) and then the appropriate incomer relay will operate tripping the transformer CB (500ms). On the current scheme the incomer high set elements operate and trip the bus section first as well as the closed ring CB on Section A, then the appropriate incomer CB will operate tripping the transformer. In this situation only half the board is lost but also supplies to the closed ring will be lost which can be restored by control.

### C2.4 Phase Fault on Transformer Tails

A phase fault on the transformer tails, as shown by F3 on the diagram, will cause the directional overcurrent element on that incomer to pickup. The starter for this element will provide a blocking signal (via an output relay) to the high set elements in both incomers and the bus section. When the directional relay operates a trip signal is sent and only the incomer CB with the fault on will open and supplies to the rest of the board will be maintained from the other incomer.

When the trip signal is issued a CB fail timer is started and if the incoming CB fails to open within the specified time then the blocking signal is removed (via a second output relay). The high set elements then operate causing the bus section and appropriate closed ring CB to trip first followed by the appropriate incomer CB.

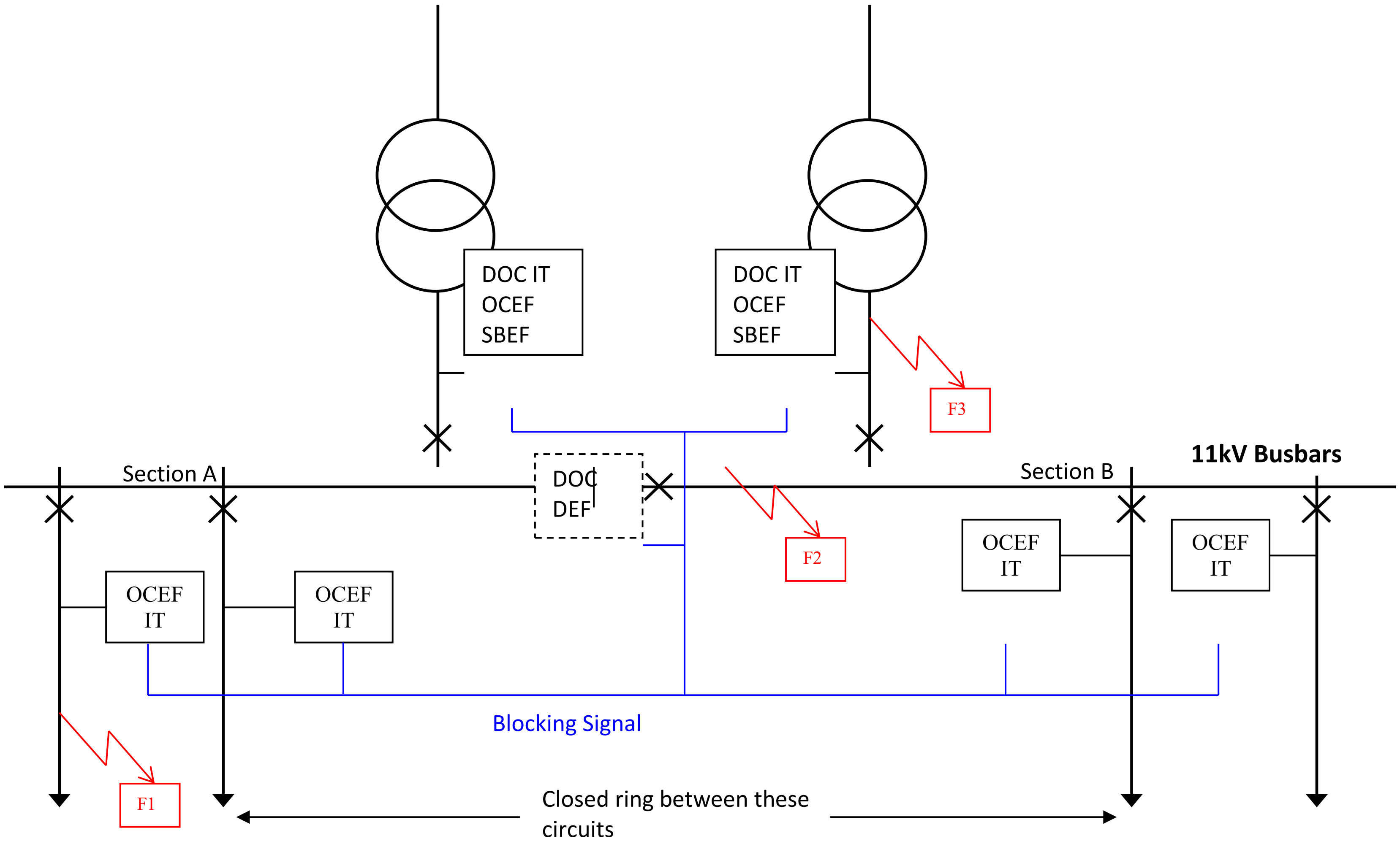
It should be noted that operation of the DOC protection will also intertrip to clear the 33kV feeder. If the 11kV CB fails to open from the DOC trip signal then the fault will still be being fed from the other incomer via the bus section and hence the need to trip the bus section and completely isolate the fault. This is left as a last stage because if everything works normally then all supplies will be maintained on the primary board via a single incomer.

### C2.5 Earth Fault on the Transformer Tails

For an earth fault on the transformer tails the restricted earth fault protection should operate in a very short time (~40ms). This would trip the incomer 11kV circuit breaker and intertrip the remote 33kV circuit breaker (note – on modern schemes this is done via the Delta relay on the incomer). This would maintain supplies to all the primary board assuming correct operation.

The standby earth fault IDMT and high set elements should also see the fault. If the 11kV incomer circuit breaker fails to open then, without any other blocking being applied, the high set elements that began timing at the start of the fault should operate with the bus section tripping first along with the appropriate closed ring CB and subsequently another trip signal to the incomer and intertrip to the remote 33kV end. As in the other schemes this would mean loss of half the board for a stuck breaker.

**Diagram C1 – Operation of Busbar Blocking and CB Fail Scheme**



# Appendix D – Quality of Supply Project Protection Setting Change Procedure

| | |
|---|---|
| **METHOD STATEMENT:- Protection Setting Changes for Quality of Supply Work** | **ISSUE:- 2** |
| | **DATE:- OCT 2014** |

## D1 Introduction

As part of the Quality of Supply (QoS) program of work to improve network performance, the protection settings for distribution circuits are being reviewed. This will result in revised protection settings needing to be applied to hundreds of circuits at either ground mounted, pole mounted, network or primary circuit breakers.

This method statement describes the process to be applied for changing protection settings that have been issued as part of the QoS program.

## D2 Existing Protection Policy CP606 S48

CP606 S48 states the existing process for changing of settings in either a planned or fault/emergency situation. The existing S48 procedure states that for planned changes of settings these shall be applied and tested in order to prove operation of the protection and the trip circuit, which requires an outage.

In order to facilitate the changing of settings across a large number of distribution circuits as part of the QoS work an exception to S48 has been agreed. The process outlined in section 3 is permitted to be used for changing protection settings for the QoS program.

## D3 Protection Setting Change Process

The changing of protection settings will require changes to be made to a wide variety of relays (electromechanical, older electronic, modern numeric) and in different situations at either primary or network substations and pole mounted equipment. This process is intended to be generic to all of these situations but any specific issues with certain types will be highlighted in the process.

The process to be followed :

1. Competent engineer to confirm that communication to DSMC Control is satisfactory via mobile phone and substation phone where fitted. Note that the alternate number for control is:
   - Second Contact HV Support – 0161 779 0029
2. Competent engineer to confirm with DSMC Control that there are no abnormalities, restrictions or any outages that could impact on the proposed Protection Setting changes.
3. Control engineer to log:
   - Location

- Activity
- Staff name
- Contact number
- Start time

4. Competent engineer to undertake on site Risk Assessment.

5. Competent engineer in receipt of revised protection settings from the planning engineer, to be checked and compared against the relay on site (Note – this is particularly important for VIP relays which have a x2 or x4 setting which is physically wired into connections on top of the relay. If the physically wired connection needs changing then switching will be required and this process CANNOT be used).

6. Agree a Risk of Trip with the Control engineer for the circuits to be worked on. This can be a sequence of circuits if in one location (for example at a primary).

7. Request DSMC Control disable any Auto Reclosing or FLISR that has been applied to the circuit. The HAEL will suffice for the logging of this activity, it is not required to log each item in the Control log or to generate a Switching programme.

8. The engineer to put any remote control (RC) device into Local prior to any protection work commencing.

9. The relay settings to be changed as required:

   - For modern numeric relays this will involve entering the appropriate menus and changing settings accordingly (alternatively connecting via a laptop and loading a setting file)
   - For older electronic relays this will mean changing DIL switch positions.
   - On electromechanical relays where a plug setting change is required then the engineer to assess whether a second plug can be used. Where possible this to be inserted in as high a setting as practical and then the existing plug removed. Where it is not possible it is permissible for the existing plug to be removed and placed into the required setting position.

10. For any inadvertent operation of any device at the work location.

    - The Engineer is to contact DSMC Control immediately providing as much known information as to the cause of trip and if suspect related to Protection Settings change.
    - Control engineer to cancel the ‘Risk of Trip’.
    - The Engineer to confirm correct Protection Settings applied and request appropriate action from DSMC Control.

11. On successful completion of the setting changes notify Control and cancel the’ Risk of Trip’.

12. The competent engineer to restore any RC device to remote.

13. DSMC Control to restore all Auto reclosing or FLISR functionality as appropriate.

14. Control engineer to log:

- Completion time.
- Any associated abnormalities.

## D4 References

CP606

# Appendix E – Connection and Addressing of Relays Using DNP3 Communications

## E1 Introduction

The use of DNP3 communications between relays and the SCADA RTU is being implemented in Electricity North West Limited initially in Primary substations. The use of DNP3 will cover all alarms, analogues and controls between the circuit breaker and telecontrol. This appendix describes the method by which communications will be hard wired across the switchboard and to the RTU and how the relays will have their addresses set in order to provide a standardised structure to be applied across Electricity North West Limited.

## E2 Addressing of Relays

The first relays installed using DNP3 communications have a maximum DNP address limit of 65519. It is proposed to utilise the five digit address number using the following structure.

| Digit 1<br>Voltage | Digits 2 & 3<br>Circuit Number | Digit 4<br>Relay Number | Digit 5<br>IED String Number |
|---|---|---|---|
| 6.6kV = 3 | 01 | 1 | 1 |
| 11kV = 4 | 02 | 2 | 2 |
| 33kV = 5 | 54 | 8 | 8 |
| 132kV = 6 | 55 | 9 | 9 |
| Highest voltage level applied to device | Circuit breaker number (accounting for future spare bays) | Specific relay ID number on CB (always starts at 1) | DNP3 communications string number |
| (Max 6) | (Max 55) | (Max 9) | (Max 9) |

Example 1

DNP3 address associated with second relay on incomer circuit breaker of 11kV switchboard. Circuit breaker is 12th circuit breaker on switchboard noting CB positions 1 and 2 are future spare bays. The circuit breaker is installed on section B, thus connected to the second IED string.

**DNP3 Address = 41222**

Example 2

DNP3 address associated with first relay on feeder circuit breaker of 11kV switchboard. Circuit breaker is 6th circuit breaker on switchboard noting CB positions 1 and 2 are future spare bays. The circuit breaker is installed on section A, thus connected to the first IED string.

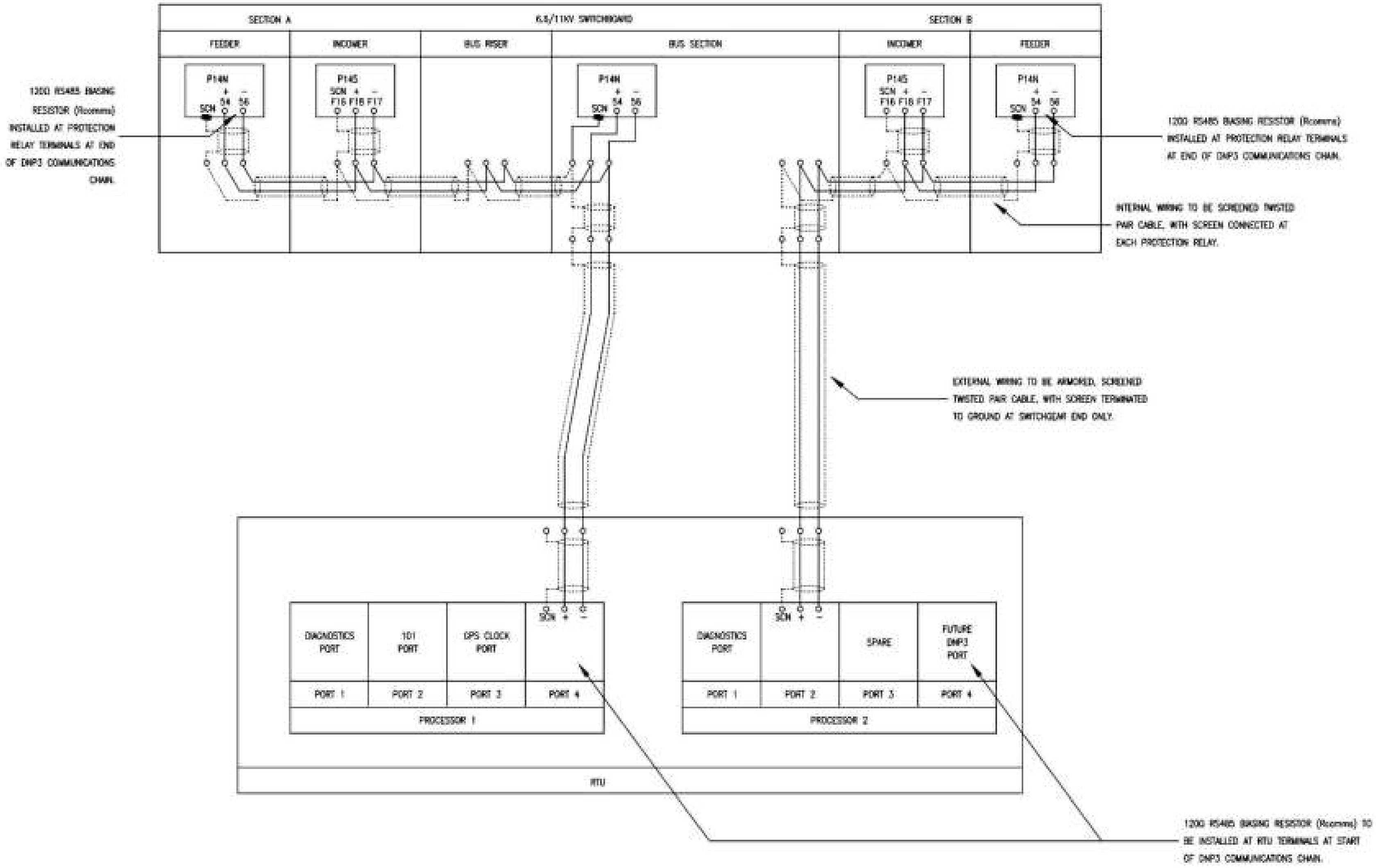
**DNP3 Adrress =40611**

## E3 Physical Communications Layout

The drawing E1 illustrates the proposed physical layout of the communications links. There are two separate communications circuits, one for each section of busbar, each going to a separate port on different processor cards in the RTU. This methodology should prevent a single point of failure from a communications perspective.

The RS485 communications circuit is looped between the relays on each section with a termination resistor added to the final relay connection at the bus wire terminal blocks. Should an extension circuit breaker be fitted in the future this can be added to the communications loop and the resistor moved to the new end of the communications circuit, again located at the bus-wire terminal blocks.

All terminal blocks associated with the communications circuit wiring shall be of the isolatable type to facilitate the disconnection of relays associated with an individual circuit breaker without affecting other devices connected to the associated communications circuit. These terminals shall also facilitate the connection of $4mm^2$ test lead plugs for either the connection to an individual relay locally at the circuit breaker or the entire communications circuit at the bus-section.


SECTION A
6.6/11KV SWITCHBOARD
SECTION B
FEEDER
INCOMER
BUS RISER
BUS SECTION
INCOMER
FEEDER
P14N
P145
P14N
P145
P14N
SCN
54
56
F16 F18 F17
120Ω RS485 BIASING RESISTOR (Rcomms) INSTALLED AT PROTECTION RELAY TERMINALS AT END OF DNP3 COMMUNICATIONS CHAIN.
120Ω RS485 BIASING RESISTOR (Rcomms) INSTALLED AT PROTECTION RELAY TERMINALS AT END OF DNP3 COMMUNICATIONS CHAIN.
INTERNAL WIRING TO BE SCREENED TWISTED PAIR CABLE, WITH SCREEN CONNECTED AT EACH PROTECTION RELAY.
EXTERNAL WIRING TO BE ARMORED, SCREENED TWISTED PAIR CABLE, WITH SCREEN TERMINATED TO GROUND AT SWITCHGEAR END ONLY.
DIAGNOSTICS PORT
101 PORT
GPS CLOCK PORT
PORT 1
PORT 2
PORT 3
PORT 4
PROCESSOR 1
DIAGNOSTICS PORT
SPARE
FUTURE DNP3 PORT
PORT 1
PORT 2
PORT 3
PORT 4
PROCESSOR 2
RTU
120Ω RS485 BIASING RESISTOR (Rcomms) TO BE INSTALLED AT RTU TERMINALS AT START OF DNP3 COMMUNICATIONS CHAIN.