AMS 10-68 Protection (Secondary) Systems

Protection, Control, Monitoring & Metering Assets

2023-27 Transmission Revenue Reset

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1 Executive Summary

Protection assets are combined in systems to detect electrical faults on the transmission network and, via the operation of circuit breakers, rapidly disconnect faulted circuits from sound circuits. Protection systems are designed to protect operators and the public from hazardous electrical conditions, limit damage to network equipment and maintain the network's electrical operating parameters within selected limits to ensure reliable energy supplies to consumers.

Secondary assets include devices to measure the network's electrical operating parameters and monitor the function and condition of selected primary network assets. This data is essential for the effective tactical operation of the network, fulfilling commercial agreements between connected parties and the strategic management of primary assets. Examples include revenue metering, power quality monitoring, transformer loading and temperature measurement, circuit breaker operation, and monitoring insulating oil degradation and prevailing weather.

Control assets are arranged in systems to provide automatic or remote manual control of the function of primary assets. These systems are essential for the effective and efficient control of power flows within the network and include functions such as transformer voltage regulation and cooling system control, reactive voltage control, load shedding and runback schemes.

Secondary system technologies evolve rapidly. In a relatively short period of time electromagnetic technology was superseded by analogue electronics, then by digital electronics and further by microprocessors which integrated multiple functions. Intelligent electronic devices with flexible integration, programmability and configurability are now in use.

Secondary assets become obsolete within a typical timeframe of 15 years when they are no longer supported by manufacturers, are technically incompatible with interfacing equipment or are no longer able to provide the functionality established in industry standards or regulation.

1.1 Key Strategies

An overarching strategy is to integrate secondary asset modernisation projects within Terminal Station rebuild projects or major primary asset replacement projects wherever economic. This approach ensures better technical and economic outcomes with efficient design, coordinated delivery and fewer circuit outages during implementation. Stand-alone secondary projects are initiated only where no suitable Terminal Station rebuild project or primary asset replacement project is planned in an appropriate timeframe and asset condition warrants replacement or augmentation.

Key strategies for the secondary systems assets include:

1.1.1 New Assets

- All new and replacement assets will be designed In accordance with the Station Design Maul and current design standards, undertake replacement of complete protection systems (i.e. X, Y, backup and necessary control and monitoring systems) associated with individual items of primary plant/network sections, rather than individual protection schemes/relays
- Replacement activities shall be incorporated within primary plant replacement, station refurbishment or network augmentation activities as far as practicable, in order to maximise operational efficiency and minimise network disruption

1.1.2 Maintenance and Inspection

- Continue to maintain protection and control assets (including RTUs) as per PGI 02-01-02 and the SPP 02-00-01 suite of documents
- Maintain PGI 02-01-02 and the SPP 02-00-01 suite of documents consistent with the outcomes of ongoing Enhanced Data-Driven Asset Management (EDDAM) studies

1.1.3 Spares

The use of spare equipment will allow prompt recovery of the transmission network during secondary assets failure.

- Continue to maintain sufficient spares to ensure ongoing maintainability of in-service devices
- Maintain decommissioned assets in appropriate working condition as spares, as required to ensure the ongoing serviceability of in-service, poor condition/obsolete assets pending retirement
- Continue to consider device obsolescence, as advised by asset manufacturers and suppliers, in preparation of asset replacement strategies
- In case where spares for complex equipment are not available, prepare emergency replacement schemes with marked-up drawings and device settings for use during emergencies

1.1.4 Replacement

- Integrate secondary asset modernisation projects within terminal station rebuilt project or major asset replacement projects whenever economic
- Targeting the protection, control, metering and monitoring asset replacement with the worst asset condition and with the highest risk of failures.
- The replacement of the assets (RTUs) with a SCIMS station architecture incorporating the serial communications to IEDs and a local HMI control allowing retirement of the station mimic panels.

1.1.5 Condition Monitoring

- Provide condition monitoring to all secondary assets including secondary cabling.
- Review the condition of secondary assets and update the asset management systems as required.

2 Introduction

2.1 Purpose

The purpose of this document is to outline the inspection, maintenance, replacement and monitoring activities identified for economic life cycle management of all regulated secondary systems asset located within terminal stations in AusNet Services' Victorian electricity transmission network. This document intends to be used to inform asset management decisions and communicate the basis for activities.

In addition, this document forms part of our Asset Management System for compliance with relevant standards and regulatory requirements. This document demonstrates responsible asset management practices by outlining economically justified outcomes.

2.2 Scope

This Asset Management Strategy applies to all regulated asset base secondary systems asset located within terminal stations in the Victorian transmission network. The broad classes of secondary assets are as follows:

Protection Assets:

- Transformer Protection.
- Bus Zone Protection.
- EHV Line Protection.
- HV Line (Feeder) Protection.
- Reactive Plant Protection for Static VAR Compensators (SVC), Synchronous Compensators, Capacitors and Reactors).

Station & Network Control Assets:

- Circuit Breaker Management & Control.
- Transformer Voltage Regulation.
- Transformer Cooling Control.
- Transformer auto close schemes.
- Reactive Plant Control (SVC, Synchronous Compensators, Capacitors).
- Load Shedding Schemes.
- Special Network Control Schemes such as Very Fast Runback and Emergency Tripping schemes.

Monitoring & Metering Assets:

- Revenue Metering.
- Weather Stations.

- High Speed Monitoring.
- Power Quality Monitoring.
- Network Disturbance Recorders.

Secondary Infrastructure Assets:

- Station System Control and Data Acquisition (SCADA), Remote Terminal Units (RTUs), Human Machine Interfaces (HMI) and Station Control and Information Management Systems (SCIMS).
- Secondary Cabling.
- PACSIS Relay Database.

This strategy does not cover:

- DC Power Supplies (Batteries, Chargers & DC/DC Converters). These assets are included in a separate Asset Management Strategy document AMS 10-52.
- Communications systems for peer-to-peer communication in protection systems and communication between protection systems and remote engineering locations. Strategies for communications systems are included in Asset Management Strategy document 10-56.

2.3 Asset Management Objectives

As stated in *AMS 01-01 Asset Management System Overview*, the high-level asset management objectives are:

- Maintain network performance at the lowest sustainable cost;
- Meet customer needs now and into the future;
- Be future ready;
- Reduce safety risks; and
- Comply with legal and contractual obligations.

As stated in *AMS 10-01 Victorian Electricity Transmission Network Asset Management Strategy*, the electricity transmission network objectives are:

- Maintain top quartile benchmarking;
- Maintain reliability;
- Minimise market impact;
- Maximise network capability;
- Leverage advances in technology and data analytics;

- Minimise explosive failure risk

3 Asset Description

3.1 Asset Function

3.1.1 Protection Assets

The underlying technology of protection relays can generally be classified as either electro-mechanical electronic, analogue electronic, microprocessor-based or Intelligent Electronic Devices (IEDs).

Electromechanical (Non IEDs): Electromechanical relays are single function relays with mechanical measurement registers, rotating disc mechanisms, mechanical bearings and spring-based energy storage. Electromechanical relays represent the oldest relay technology.

Analogue Electronic (Non IEDs): Analogue Electronic relays are usually single function relays that use discrete analogue electronic components including transistors and integrated circuits, and employ capacitors for measurement.

Microprocessor-based (Non IEDs): Microprocessor-based relays can be single- or multi-function devices in which measurement is carried out by an analogue to digital conversion. This type of relay uses numerical algorithms and digital signal processing to implement protection functions.

Intelligent Electronic Devices (IEDs): An IED is an advanced type of microprocessor-based relay. They are multi-function devices with sophisticated digital programming and configuration capabilities, fault recording and digital communications. IEDs represent the most modern relay technology.

3.1.1.1. Transformer Protection

Transformer protection is provided by duplicated independent (X and Y) relays that may include a number of protection functions, the chief one being differential protection.

Differential protection compares the currents in the High Voltage, Medium Voltage and Low Voltage transformer connections and scales them appropriately for magnitude and phase angle so that the normal net sum of the currents is zero under healthy circuit conditions. If the current sum is not zero; differential protection schemes send tripping signals to relevant circuit breakers. An internal restraint circuit prevents tripping upon transformer energisation.

Modern intelligent transformer relays can also provide overload detection on any connection and receive signals from external devices such as [C-I-C] (oil surge) relays and temperature sensors. The relays are connected to SCADA and provide instrumentation and event information to the control centre.

Intelligent relays record currents during transformer faults and are of great value in analysing a transformer failure, allowing faster repair and remedial action to prevent similar failures on other transformers.

3.1.1.2. Bus Protection

Bus protection consisting of duplicated protection (X and Y) may be applied to primary circuit busbars at all voltage levels (11 kV, 22 kV, 66 kV, 220 kV, 275 kV, 330 kV and 500 kV) within terminal stations. The most commonly employed bus protection schemes are high impedance differential protection and overcurrent protection.

Electromechanical relays are preferred for used in high impedance bus protection schemes even in modern installations due to their robust construction and inherent operating stability. This accounts for the high population of electromechanical relays compared to other technology types for bus protection.

3.1.1.3. EHV Line Protection (220 kV, 275 kV, 330 kV and 500 kV)

Protection for 220 kV and higher voltage (EHV) lines is provided by duplicated independent (X and Y) relays. It is an Australian Energy Market operator (AEMO) requirement that except for an eight hour maintenance period, both relays must be in service at any one time or the line may have to be taken from service.

There are two main operating principles: distance (impedance) and current differential. Distance relays are connected to the line current and voltage transformers and measure the line impedance; they operate if the impedance is lower than the actual line impedance. The distance relays at each end of the line must be interconnected by a communications link to ensure that the AEMO specified fault clearance times are met.

Current Differential relays are connected to current transformers (CTs) on the line and continuously compare the currents at each end of a line via a high speed digital communications link. These relays operate to trip the line if a difference between the terminal currents is observed. Current differential protection offers a more clearly defined protected zone than distance protection and is applied when a suitable communications link is available between the stations.

Present generation relays may include both distance and current differential operating principles included with either or both in service. The latest relays are also able to undertake line instrumentation functions for SCADA.

3.1.1.4. HV Line Protection (66 kV and 22 kV)

Protection for 66 kV lines is provided by duplicated independent (X and Y) relays. As with the EHV protection, there are two main operating principles: distance (impedance) and current differential.

The protection clearance times for HV lines are less stringent than for EHV lines and communications links between stations are generally not necessary when distance protection is used. However, there are significant benefits associated with grading of protection schemes when differential schemes are used, and for this reason current differential protection is preferred when a suitable communications link is available

Overcurrent and/or pilot wire protection is used for some older feeders. Pilot wire protection is similar to current differential protection, but uses electro mechanical relays and analogue communication over dedicated copper telephone wires.

The present generation protection schemes for 66 kV feeders have two intelligent relays (X and Y) each including distance and/or differential, but with the additional functions of CB Failure detection, CB control, automatic reclose and instrumentation. In some applications, distance protection is required to ensure adequate backup protection is provided for downstream assets.

3.1.1.5. Reactive Plant Protection

Reactive plant includes fixed capacity Capacitors and Reactors, and variable capacity Synchronous Compensators and Static VAR Compensators.

For fixed capacity Capacitors and Reactors:

- Protection for fixed capacity reactors is similar to that used for transformers: differential, overcurrent and [C-I-C] (gas).
- For fixed capacitors, overcurrent protection that operates from the total current into the capacitor is used. A separate sensitive current balance overcurrent circuit is also provided to detect failure of pre-determined number of capacitor cans in each phase of a capacitor bank. Detection of the unbalanced current and subsequent tripping of the capacitor bank will prevent further failure of remaining capacitor cans due to overvoltage. Some relays also have a thermal overload function based on an internal model of the capacitor characteristic.

For Synchronous Compensators:

- Synchronous Compensators, all with over 40 years of service, are fitted with individual relays providing overcurrent, overvoltage and current differential protection, together with additional items for Hydrogen Gas coolant, starting motor, voltage control and synchronising.

For Static VAR Compensators (SVC):

- Static VAR Compensators (SVC) comprise of individual capacitor and reactor elements switched by thyristors. Protection for the capacitors and reactors is by individual overcurrent, overvoltage and differential relays, comprising up to 20 individual relays. The high voltage thyristors are connected in series, with their combined rated voltage limit greater than the system voltage. Each thyristor is monitored so that when failure of one thyristor is detected, the SVC will be turned off to prevent overvoltage failure on the remaining thyristors. There are also protection circuits to detect failure of the water cooling systems for the thyristors.
- A special case is the Series Capacitor installations on the two DDTS-SMTS 330 kV lines. The Series Capacitors are effectively part of the lines and protection against primary insulation failure is provided by the 330 kV line protections. However, special protection is needed to detect sudden high currents during 330 kV line faults. Excessive voltage across the series string of 180 cans triggers an arc in the air gap

provided. This arc effectively shunts the cans and protects them from overvoltage failure. The short circuit provided by the spark gap is immediately backed up with the closure of a Bypass CB. A separate monitoring circuit integrates ambient temperature, current and time to prevent thermal overload.

3.1.2 Station & Network Control Assets

3.1.2.1. Circuit Breaker Management & Control

Circuit breaker management relays provide CB fail, auto reclose, local and remote control and instrumentation functionality for circuit breakers within one device. CB management relays are used in modern schemes in place of discrete control and instrumentation devices. Strategic integration of these devices throughout the transmission network facilitates progressive retirement of analogue instrumentation and obsolete control infrastructure whilst maximising operational capability for the network.

Circuit breaker management relay and control equipment has the intelligence to control the CB itself, providing statuses and alarms information to local HMI and the control centre. It also provides the synchronism check function to the CB to interlock the CB Close command with pre-determined system voltage conditions.

Moreover, it provides CB Failure protection function that opens adjacent CBs when the CB concerned has failed to open during fault incidents.

The CB Management relay is connected to the CB current transformers, voltage transformers on both sides of the CB, CB control circuits and trip circuits for adjacent CBs.

3.1.3 Monitoring & Metering Assets

3.1.3.1. Revenue Metering

Transmission Revenue Meters and provides *Responsible Person Services* under the National Electricity Rules (NER). These revenue meters monitor wholesale energy flows, and facilitate invoicing amongst National Electricity Market (NEM) participants.

AusNet Services also provide Meter Provider and Meter Data Provider Services via a subsidiary company called Mondo. The meters and their associated CTs and VTs are tested regularly according to the requirements of the NER.

The following table summarises the AusNet Services metering installations by type as defined by the NER.

Table 1: Revenue Meters by Type

NER METER TYPE	DEFINITION
TYPE 1	Annual Energy Throughput greater than 1,000 GWh
TYPE 2	Annual Energy Throughput between 100 and 1,000 GWh
TYPE 3	Annual Energy Throughput from 0.75 GWh to less than 100 GWh
TYPE 4	Annual Energy Throughput less than 0.75 GWh
CHECK Meters	Check Meters for Type 1 and 2 Installations

3.1.3.2. Terminal Station Weather Stations

There are 24 weather monitoring installations located within AusNet Services' terminal stations. They are located at:

- BATS
- BETS
- CBTS
- DDTS
- FTS
- GNTS
- GTS
- HOTS
- HWTS
- HYTS
- KGTS
- KTS
- MARY ST
- MBTS
- MLTS
- MTS
- RCTS
- ROTS
- RTS
- SHTS
- SVTS
- TGTS
- WOTS
- YPS

These weather stations were installed in 2005 to provide AEMO the following information via Remote Terminal Units:

- Wind speed – anemometer and Ultrasonic
- Wind direction;
- Ambient temperature;
- Barometric pressure

These weather stations have worked well since installation, however not all stations transmit all available data to the Network Control Centre. Table 2 summarises the sensors installed and data available at the Network Control Centre.

They are expected to have a remaining service life of 5 to 10years.

Table 2: Weather Sensors and data availability to Network Control Centre

		Temperature	Anemometer Wind Speed	Ultrasonic Wind Speed	Wind Direction	Barometric Pressure
1	BATS	X	X	X	X	X

2	BETS	X	X	X	X	X
3	CBTS	X	X	X	X	X
4	DDTS	X				
5	FTS	X	X	X	X	X
6	GNTS	X			X	X
7	GTS	X	X	X	X	X
8	HOTS	X	X	X	X	X
9	HWTS	X	X	X	X	X
10	HYTS	X				
11	KGTS	X	X	X	X	X
12	KTS	X	X	X	X	X
13	MARY ST	X				
14	MBTS	X	X	X	X	X
15	MLTS	X	X	X	X	X
16	MTS	X	X	X	X	X
17	RCTS	X	X	X	X	X
18	ROTS	X	X	X	X	X
19	RTS	X				
20	SHTS	X	X	X	X	X
21	SVTS	X	X			
22	TGTS	X			X	X
23	WOTS	X				
24	YPS	X	X	X	X	X

3.1.4 Secondary Infrastructure Assets

3.1.4.1. Station SCADA (RTUs / HMI / SCIMS)

The SCADA systems gather remote station data such as instrumentation (volts, amps, frequency, Watts, VARs, transformer temperature, conductor strain, environmental monitoring, etc.) circuit breaker and plant status, station alarms, etc., interprets it and displays information to operations personnel to guide control of the network.

SCADA assets can be categorised into six technology types: Electronic (oldest), First Generation Microprocessor, Second Generation Microprocessor, Third Generation Microprocessor, Current Generation Microprocessor and PC-based Microprocessor.

The majority of SCADA systems in service throughout the electricity transmission network are First Generation Microprocessor and Third Generation Microprocessor assets.

3.2 Asset Population

There are approximately 6566 protection relays operating in the Electricity Transmission Network, as reported in the 2018 RIN.

3.2.1 Population by Device Type

Figure 1 below shows the proportion of IED and non-IED devices in services.

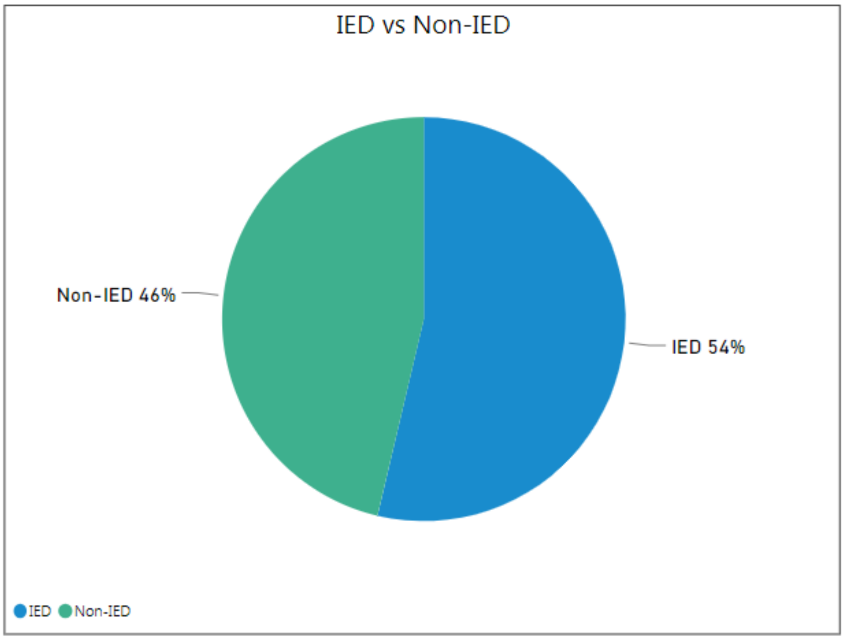

Figure 1 Population of IED and non-IED Protection Assets

The population of the Digital relay IED is expected to increase going forward as older assets reach the end of their technical and economic life. IEDs provide superior functionality for protection applications and are deployed as standard for all new and replacement installations.

3.2.2 Relay Application by Associated Primary Plant

The breakdown of primary plant associated with the protection relays is shown in Figure 2.

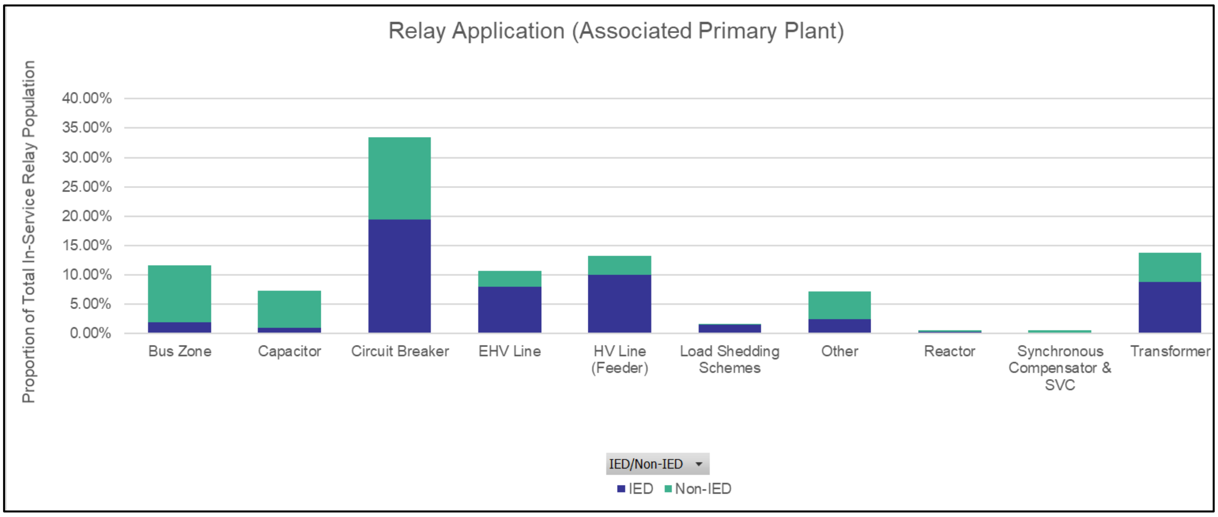

Figure 2 Population by Protection Type

3.2.3 Remote Terminal Units (RTUs)

There are 67 RTU systems operating in the Electricity Transmission Network, as reported in the 2018 RIN.

There are five (5) models of remote terminal units (RTUs) currently in service on the AusNet Services transmission network Figure 3 provides an overview of the population distribution.

[C-I-C]

Figure 3 Population by RTU type

The [C-I-C] and [C-I-C] are the oldest RTU types employed in Ausnet Services transmission network. There are only 3 [C-I-C] and and 2 [C-I-C] RTU remaining in service. Both types of the RTU will be included in the TRR replacement program if not already covered in an existing project.

[C-I-C] type RTU is the next oldest RTU type currently in service. SCADA services to 20% of terminal station are currently supplied via RTU of this type. The replacement strategy of this type of RTU will be based on the [C-I-C] protocol used with the RTU which will in turn reduce significant infrastructure and footprint from data centres.

The [C-I-C] and [C-I-C] RTUs are a relatively new product which was introduced to the market about 15 years ago. AusNet Services commenced installation of these RTUs about 10 years ago, in place of the already obsolete MD1000s. This number will increase significantly over the next 10 years as the current in-service population of C50 and RTU50 units are replaced.

3.2.4 Revenue Metering

There are 899 metering systems operating in the Electricity Transmission Network, as reported in the 2018 RIN.

There are currently 2 types of revenue metering installed in the transmission network, [C-I-C] and [C-I-C]. The number of devices of each type currently in service is indicated in Figure 4 below:

[C-I-C]

Figure 4 Revenue Metering by Type

3.3 Asset Age Profile

3.3.1 Protection and control

The service age profile for protection relays at terminal stations within the Electricity Transmission network is shown below:

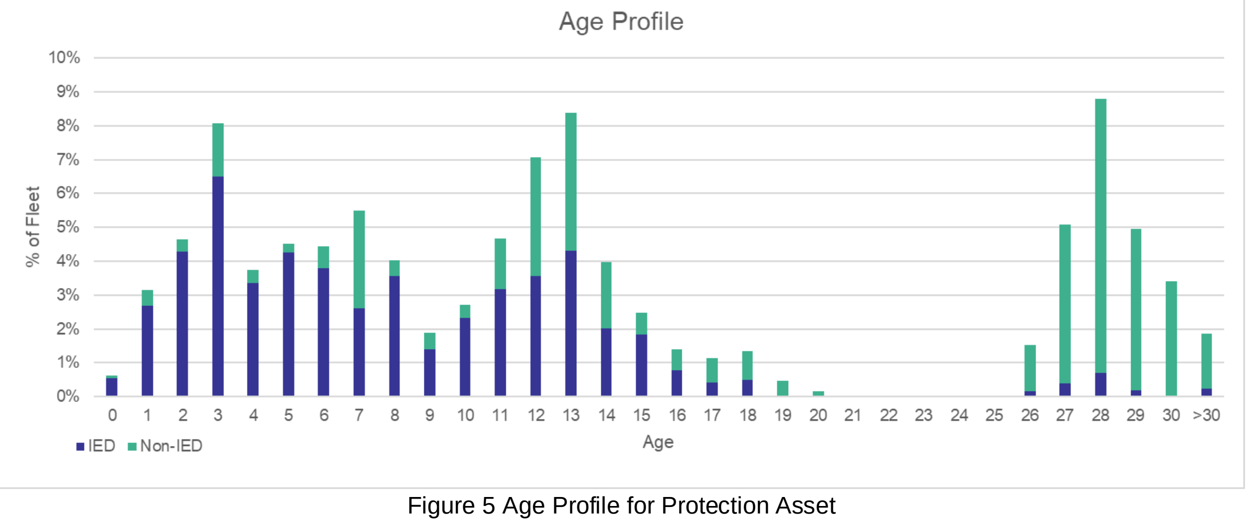

Figure 5 Age Profile for Protection Asset

3.3.2 Remote Terminal Units (RTUs)

The in- service age profile for RTUs at terminal stations within the Electricity Transmission network is shown below:

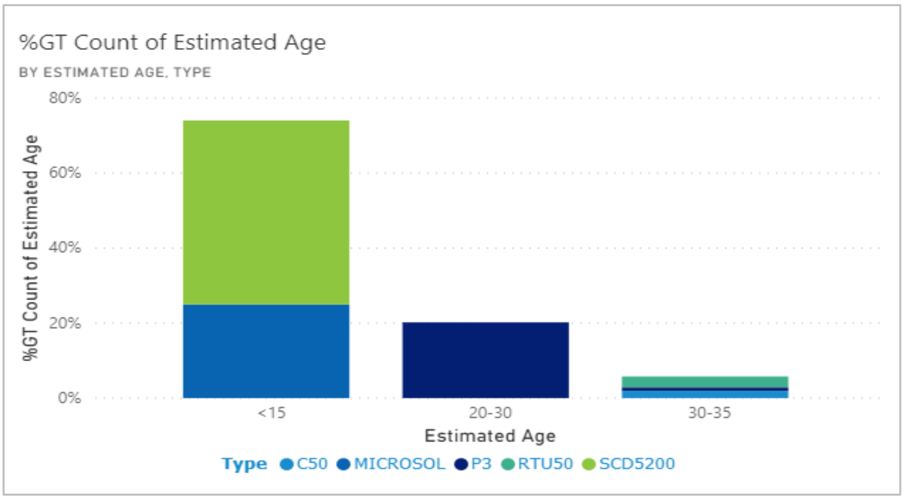

Figure 6 Age Profile for RTUs

3.3.3 Revenue Metering

The snapshot below shows the of the age profile of the revenue metering currently in services across the AusNet Services transmission network.

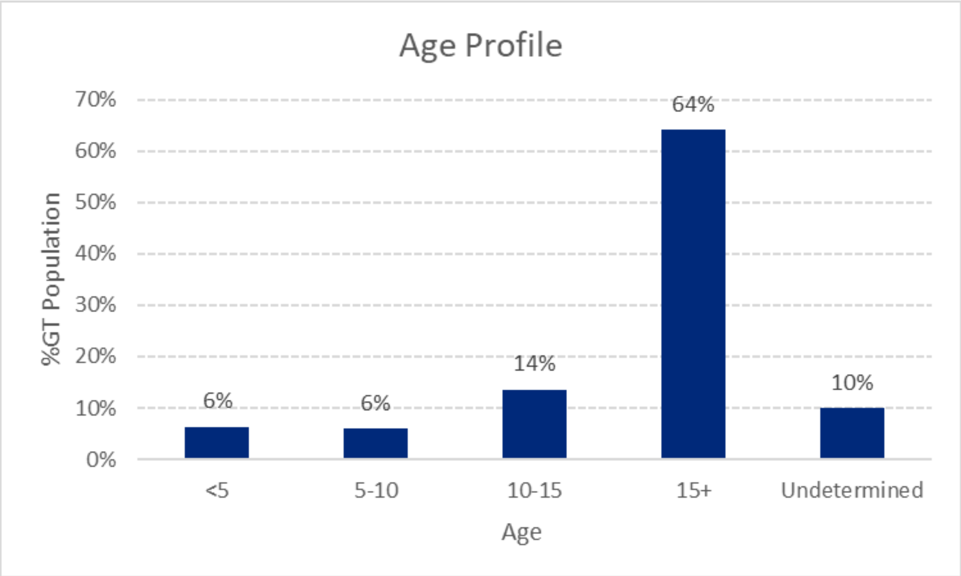

Figure 7 Age Profile for Revenue Metering

3.4 Asset Condition

The capability of a protection or control relay to deliver its expected function appropriately has been assessed for condition assessment.

The condition of each relay has been assessed on a combined score for compliance, reliability, modernisation and obsolescence. Further detailed information regarding the condition assessment framework, specific issues, conditional maintenance activities and discussion of failures, can refer to *AHR 10-68 Asset Health Report Victorian Electricity Transmission Network Secondary Systems (Protection and Control Relays and Remote Terminal Units) and Revenue Metering.*

3.4.1 Condition Summary for Relays

3.4.1.1. Condition by Device Type

Condition summary for in-service protection relays is shown in Figure 8.

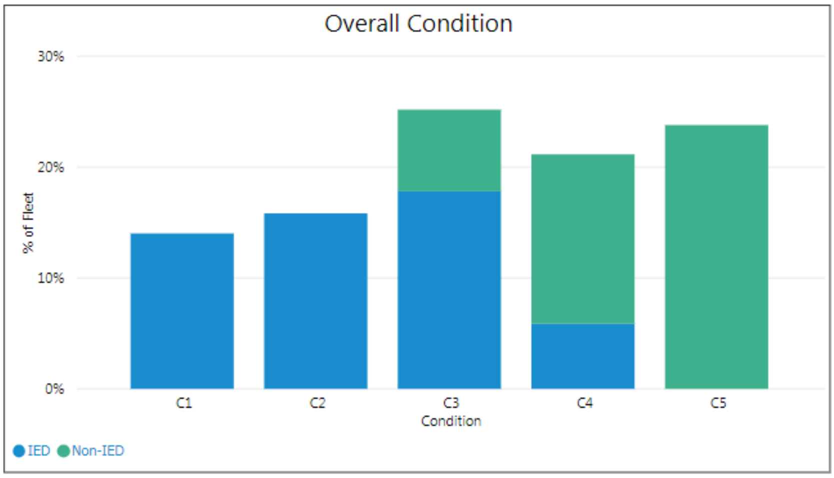

Figure 8 Condition Assessment for Protection Relays

3.4.1.2. Condition by Application

Figure 9 shows the condition of relays associated with the respective primary equipment.

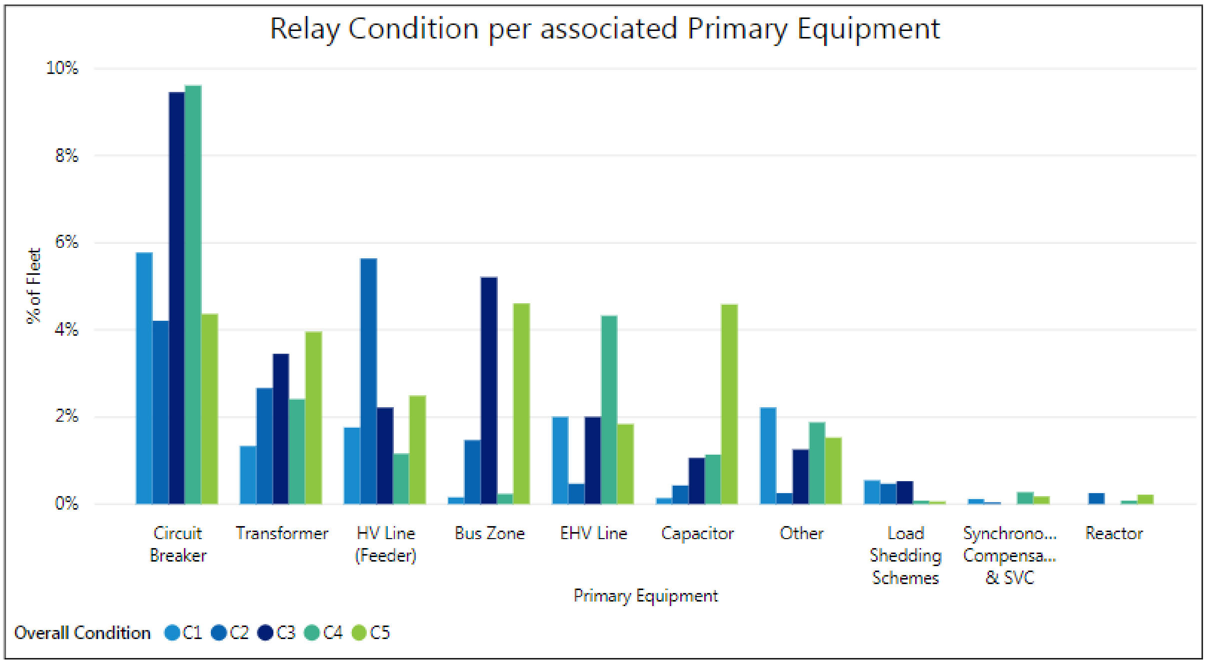

Figure 9 -Condition by Primary Equipment Type

3.4.2 Condition Summary for RTUs

Figure 10 provides an overview of RTU conditions across the transmission network.

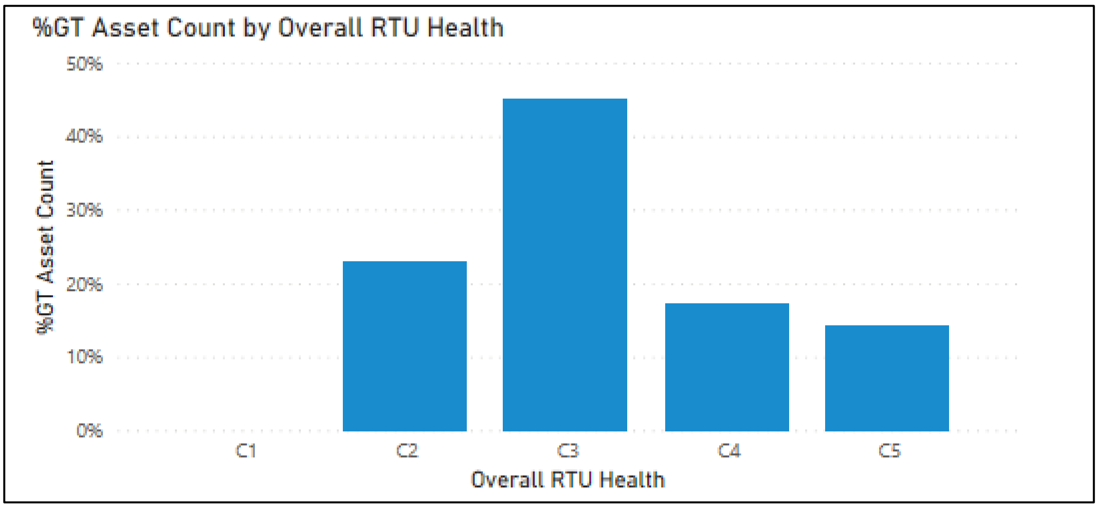

Figure 10 Condition Assessment for RTUs

Due to their limited capabilities and functions, the [C-I-C] RTU is considered to be in condition C4. However, if the RTU is using [C-I-C] protocol, the overall RTU health will be degraded to C5 condition. RTU hardware is no longer produced nor supported by the manufacturer. It cannot provide communication capabilities to IEDs. The C50 does have the ability for hardwired expansion, but only to a limited extent. The power supply used by [C-I-C]type RTUs has a high failure frequency which leads to invisibility of station operational status due to a single point of failure. The [C-I-C] protocol that uses in these RTUs has a limited number of station addresses and limited quantity of data. In addition, the protocol relies on error detection, rather than correction (as do most SCADA protocols).

Due to their age, limited capabilities, and functions, the [C-I-C], the modified version of the [C-I-C] RTUs, [C-I-C] are considered to be in condition C5. These units are obsolete, and there are no spares are available for use in case of failure. The in-service units are rapidly approaching full capacity and cannot be expanded to meet the growing demands of 'smart' station equipment. A lack of inherent redundancy means stations employing [C-I-C] are subject to an increased level of risk due to: -

- Standard used of "grouped" alarms, whereby critical station equipment alarms are combined into a single alarm point.

[C-I-C] and [C-I-C] RTUs are in condition C2 due to their availability and wide range of communication capabilities. The [C-I-C] and [C-I-C] RTUs provides all communication protocols currently used by the business, and the option of optical fibre interface.

3.4.3 Condition Summary Revenue Metering

All [C-I-C] and [C-I-C] meters are of electronics devices. [C-I-C] meter generally do not exhibit physical signs of failure. However, they do have a design life and can randomly fail at any time after this design life.

The failure of the revenue metering may require either full check meter or partial check meter to supply the information until the faulty revenue metering is replaced within an agreed timeframe.

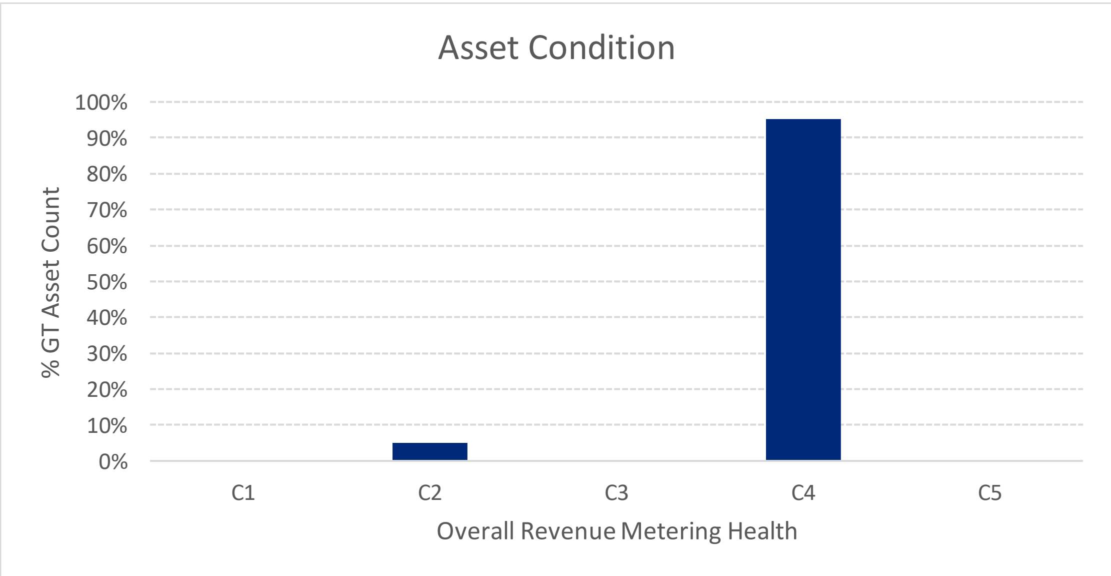

Figure 11 Condition Assessment for Revenue Metering

3.5 Asset Criticality

3.5.1 Protection and Control Relays

An interpretation of the criticality of a protection or control system is dependent upon the type of failure considered and the potential consequences of that failure. (refer also Section 3.6 Asset Performance) a ranking in terms of the potential value of unserved energy (VUE) in case of outage of the associated primary plant or network element (for example, due to spurious operation of the protection system) is the usual approach as this is statistically the most likely impact of protection (or control) asset failure. The "relative base" criticality thus determined may be adjusted by the asset condition and an assessment of device availability (refer Section 5.5.1) to determine relative asset risk.

Figure 12 provides a summary of the relative base criticalities of in-service protection and control relays, classified by relay technology type.

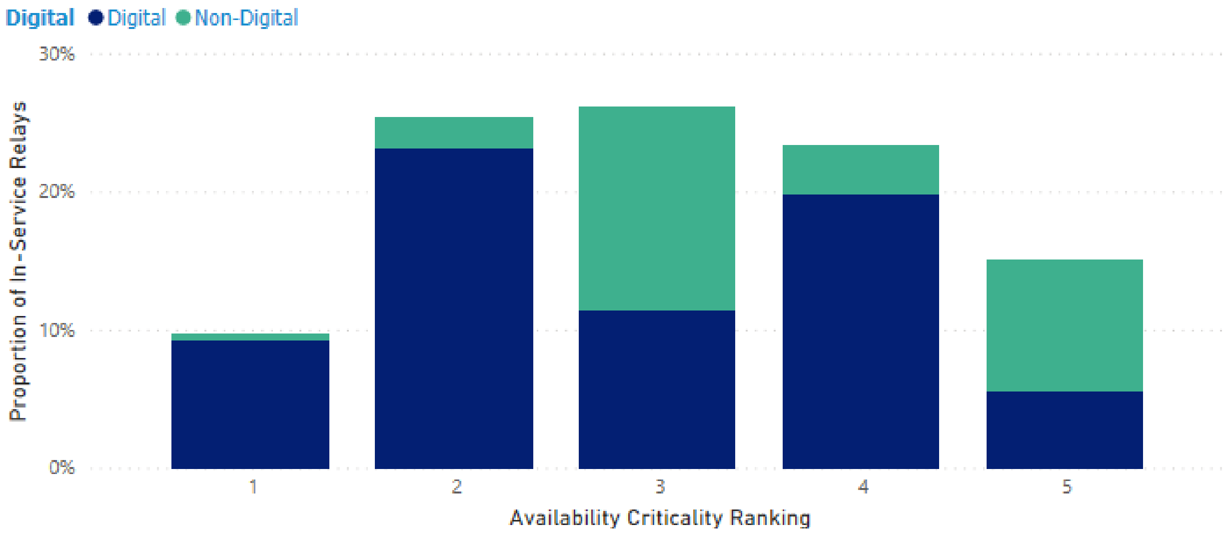

Figure 12 Relative Base Criticality of In-Service Protection and Control Relays, classified by relay technology type

The applied interpretation of relative base criticality is shown in Table 3

Table 3 Interpretation of Relative Base Criticality

Criticality Bands		Definition
1	Very Low	Potential VUE < 0.3 times Scheme Replacement Cost
2	Low	Potential VUE is between 0.3 – 1.0 times of Scheme Replacement Cost

3	Medium	Potential VUE is between 1.0 - 3 times of Scheme Replacement Cost
4	High	Potential VUE is between 3 -10 times of Scheme Replacement Cost
5	Very High	Potential VUE exceeds 10 times of Scheme Replacement Cost

3.5.2 Remote Terminal Units

The consequence of a failure of a terminal station RTU has in general limited effect on the primary network availability and performance. However, total RTU failure requires that the station be manned until it can be repaired or replaced, which does increase operational costs and reduce operational efficiencies.

3.5.3 Revenue Metering

A long period of revenue metering failure may result in non-compliance with AEMO's requirement and will increase the risk of losing the licence to operate transmission network.

AEMO requires network information acquired by revenue metering to bill the relevant parties. The failure is place unnecessary constraints on the market billing purposes.

3.5.4 Legislation and Regulatory Requirements

As a Transmission Network Service Provider (TNSP) in Victoria, AusNet Services must meet the following obligations:

3.5.4.1. Electricity Safety Act (Section 98(a))

The Electricity Safety Act (section 98(a)) requires AusNet Services to "*design, construct, operate, maintain and decommission its supply network to minimise, so far as practicable, the hazards and risks to the safety of any person arising from the supply network; having regard to the:*

a) Severity of the hazard or risk in question; and
b) State of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and
c) Availability and suitability of ways to remove or mitigate the hazard or risk; and
d) *Cost of removing or mitigating the hazard or risk*"

3.5.4.2. National Electricity Rule (Clause 6.5.7)

Clause 6.5.7 of the National Electricity Rules requires AusNet Services to propose capital expenditures necessary to:

- *"meet or manage the expected demand for standard control services over that period;*
- *Comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;*
- *Maintain the quality, reliability and security of supply of standard control services; and*
- *Maintain the reliability, safety and security of the distribution system through the supply of standard control services"*

3.6 Asset Performance

The main objective of having a protection system is to locate and isolate the faulty circuits within the power network rapidly, effectively and safely to minimise threat to worker and public safety, any damage to equipment and risks of network instability. These requirements are defined in Chapter 5 of the National Electricity Rules.

Any protection and control system failure is associated with one of three (3) possible failure effects, detailed in section 3.6.1, 3.6.2 and 3.6.3. Nearly all protection and control system failure consequences occur as a result of failure effects 3.6.1 and 3.6.2

Transmission protection systems are required to be duplicated and fully independent. AusNet Services prepares a Defective Apparatus Report (DAR) for each system failure. Figure 13 below shows the number of DARs prepared for protection systems from 2003.

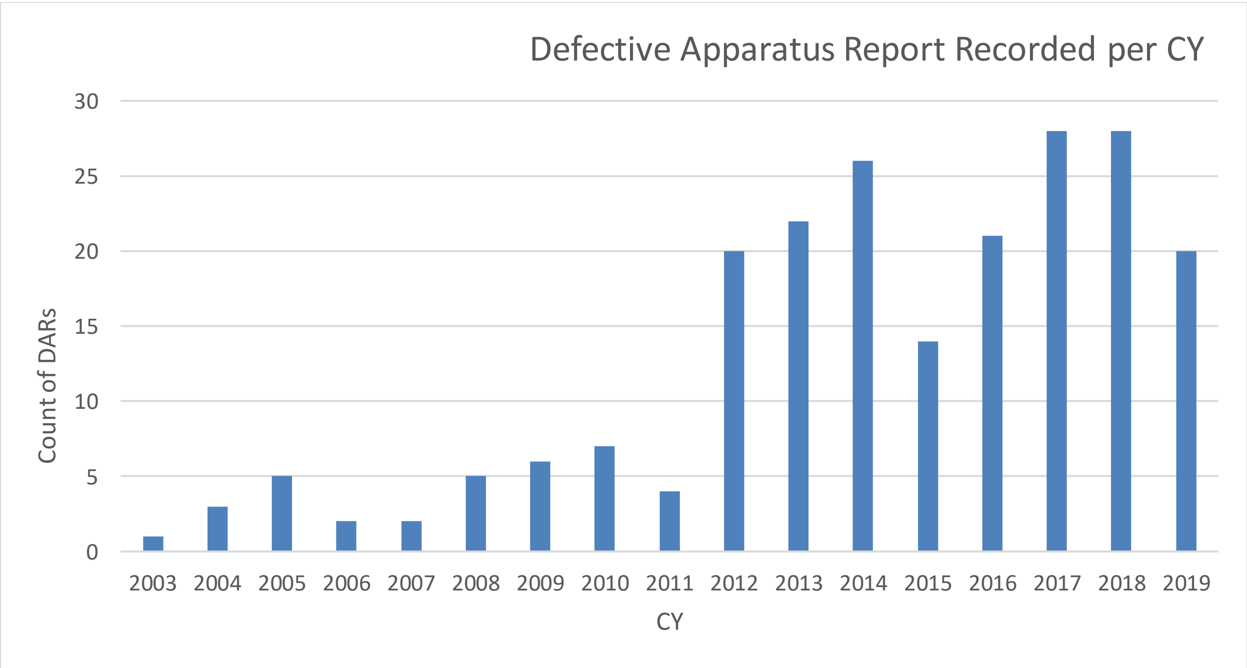

Figure 13 DARs recorded per Calendar Year

3.6.1 Spurious Operation

A spurious operation is an undesired operation of a protection or control relay that occurs in the absence of a target fault condition or control command. A spurious protection operation can present as either:-

- Operation under load when there is no fault, or
- Over-operation for (non-target) faults, leading to an outage of unaffected lines

A failure of this type results in an unnecessary network outage and an unserved energy consequence. The associated economic risk, evaluated on a "per relay" basis, is dependent upon:

- The criticality (in terms of the value of energy at risk) of the primary equipment protection (or controlled) by the protection scheme incorporating the failed device
- The time taken to diagnose and repair the failure, and restore the network to normal operation
- The cost of any associated engineering investigation, repair or replacement activity

The propensity for spurious operation is technology dependent and, for any particular relay technology, considered to be constant throughout the service life of the asset (i.e. independent of asset condition). Non-digital (electromechanical or static electronic) relays are slightly more likely to experience spurious operation due to component failure, while digital relays (intelligent electronic devices [IEDs] and first-generation micro-processor based relays) are more likely to operate spuriously as a result of human, design or logical error rather than component failure.

The benefit of a better condition asset over a poorer condition asset in this context is primarily attributed to a reduction in time taken to diagnose and repair an equipment or logical error. A C5 "Very Poor" condition asset is estimated to take up to 6 times longer to return to normal service than a C1 "Very Good" condition asset.

3.6.2 Diagnosed Asset Failure

A diagnosed failure refers to any failure within the protection or control system that is recognised by the network operators either by assertion of a condition or status alarm, or as a result of an investigation, that has not (yet) resulted in a direct consequence, but requires that a network outage be taken in anticipation of, or to facilitate, repair. The associated economic risk, evaluated on a "per relay" basis, is quantified in the same way as **Error! Reference source not found.**.

Modern, IED- based schemes have comprehensive self-monitoring, diagnostic and alarming capability which makes them slightly more likely to experience diagnosed failure compared to schemes based on non-digital relay technologies, however the consequences associated with diagnosed failure of a digital scheme is generally significantly less, and quite often allows for a failure that would otherwise be associated with spurious operation or protection system unavailability to be repaired prior to the spurious operation or "failure to operate" incident occurring.

As for, the benefit of a better condition asset over a poorer condition asset in this context is attributed to a reduction in the time taken to locate and repair the failure and restore the system to normal operation. A C5 "Very Poor" condition asset is estimated to take up to 6 times longer to repair in case of failure than a C1 "Very Good" condition asset.

3.6.3 Undiagnosed Asset Failure (“Protection system Unavailability”)

Undiagnosed failure refers to a failure within a protection or control system that is not recognised by network operators, for example because there is no capability within the protection system to diagnose or indicate the failure, no alarm, an alarm is not recognised or mal-attributed, or because a periodic fault-finding investigation has not been completed since the failure occurred. The undiagnosed failure renders the system incapable of operating as required in the event of a fault or primary asset failure, in which case the protection system is referred to as “unavailable”.

Failure of a protection system to operate on demand is associated with potentially catastrophic consequences in terms of safety, environment and collateral damage due to persistence of a fault or undesired network operational state. Any single occurrence may be considered unacceptable. The contribution of the secondary asset to network risk in this context is highly dependent upon the probability that the protected (or controlled) network element experiences a fault or primary asset failure – the more likely the fault, the more significant the contribution to network risk. The economic risk, assessed on a “per system” (rather than “per relay”) basis, manifests as an additional consequence input to the primary/network risk model. It is dependent upon:

- The degree of redundancy inherent within the failed protection or control system
- The criticality and capital value of the primary equipment protected (or controlled) by the failed system
- The geographic location of the network element protected (or controlled) by the failed system, and the likelihood and consequences of personnel or public exposure to the effects of a catastrophic asset failure or prolonged network fault
- The time taken to restore the network to normal operation (which may be considerable in the case of catastrophic asset failure)
- The cost of any associated contingency, investigation, legal, asset repair and replacement activities

This risk is difficult to quantify and a qualitative or semi-quantitative approach to risk evaluation and management is often applied in preference to an economic model. In applying such an approach, AusNet Services makes reference to Australian Standard AS IEC 61508 “Functional safety of electrical/electronic/programmable electronic safety-related systems”.

The management of unavailability risk is a primary determinant of scheduled asset maintenance requirements – where the contributing failure modes may be only be detected via scheduled fault finding investigations, the frequency at which those investigations are undertaken directly impacts the probability of the protection system being in an unavailable state between inspections. Asset maintenance strategies are currently under review to ensure maintenance of an acceptable and economically justified availability performance level.

IED-based schemes have comprehensive self-monitoring, diagnostic and alarming capability, which makes them less likely to experience undiagnosed failure compared to non-digital systems. The modernisation score component of the asset health score is an indicator of the relative availability of the asset in service. An asset with a worse (4 or 5) modernisation score is more likely to experience unavailability under the existing maintenance regime compared to an asset with a better (1 or 2) modernisation score. Asset replacement is often a better technical and economic alternative to decreasing applied fault-finding inspection intervals beyond existing protocols, particularly for high-criticality assets, and facilitates realisation of secondary benefits in terms of network modernisation.

In practice, design standards routinely employed throughout AusNet Services electricity networks (consistent with industry practice), combined with a structured periodic maintenance strategy (Section 5.2), minimises both the likelihood and impact of isolated undiagnosed asset (device) failure well below that of failure effects 3.6.1 and 3.6.2.

3.6.4 Remote Terminal Units

RTU failure can be divided into two types: hardware failure, and software constraint.

Hardware failure requires replacement of the failed component. A failed input, output or analogue card results in the loss of a subset of telemetry data supplied to SCADA via the RTU. Failure of the microprocessor or DC supply components results in the loss of visibility of the entire terminal station, and necessitates that the station be manned for manual supervision and control pending RTU repair. When no spares are available, as may be the case with older, obsolete units, replacement of the entire RTU is necessary (a costly, time and labour intensive exercise).

Software constraint is generally associated with a longer repair time due to lack of support or long lead/response times from the unit manufacturer. Manufacturer product support is thus an important aspect of software and firmware management. Without support, the RTU is associated with an increased risk of software glitches due to lack of options for firmware upgrade. It is for this reason that obsolescence and manufacturer support are a key input to asset condition assessment.

Both hardware failure and software constraint are declared failure modes, that are recognisable to the network operator via assertion of alarms or observable unit non-responsivity.

3.6.5 Revenue Metering

The failure event on revenue metering can be categorised into two components.

- Meters with hardware failures
- Meters with accuracy drifts

The common problem associated with hardware failures are the total meter failures, fibre optic intercommunication failures and the most common is failure of the meter communication to the power. The failure to the comms would require personnel to attend site to power cycle the meter each time the comms issue occurs.

4 Other Issues

4.1 Emerging Technologies

The rapid evolution of digital and other emerging technologies will continue to influence asset management decisions relating to protection and control systems.

The IEC61850 standard and associated technologies will continue to mature throughout the next 10 years, and its integration within increasingly “smart” electricity network and equipment will continue to increase. This is also anticipated to increase the requirement and criticality of centralised digital interface assets (referred to as Digital Interface Cubicles (DICs)) for the management of data traffic.

Digital Interface Cubicles also provide the capability for remote engineering access to protection and control assets, allowing relay data to be accessed from a centralised location. This capability provides opportunities to further improve operational efficiencies and decrease network incident investigation and response times. As only IEDs are capable of providing a remote engineering interface, increasing reliance on remote operability will continue to drive replacement of older assets in key locations.

The capability and specification of relays will be affected by the increasing prevalence and economic viability of alternative instrument transformer technologies, including optical CTs.

Increasing pressure from renewable energy generations, combined with evolution in telecommunication technologies, is already necessitating research and development of 3G and 4G solutions for protection signalling applications.

Rapid technological evolution places increasing demands on staff capabilities, and ongoing investment in staff training and education, and industry knowledge management in general, will become increasingly critical.

5 Risk and Options Analysis

The following strategies are employed by AusNet Services to manage the risks identified in Section 3.6:

5.1 Design

All protection and control schemes deployed throughout the electricity network are designed, as a minimum, in accordance with the Station Design Manual section 6.

In particular:

- Redundancy in design minimises the probability of protection and control system unavailability by diversifying critical paths and removing common points of failure. Redundancy in design also minimises the impact of secondary maintenance activities on primary network operations

- Design standardisation maximises engineering familiarity with in-service systems and the associated failure modes, which minimises the potential for failure due to human error, maximises the capability of personnel to operate and maintain the equipment and identify and rectify faults, while facilitating the efficient and economic management of spare parts, equipment and tools. Standardisation also ensures in-service assets consistently operate in compliance with applicable legislation, standards and best industry practice.

Asset health assessment incorporates assessment of each protection and control device and application in terms of compliance with the station design manual and current equipment standards. The poorest condition assets are generally associated with minimal (or no) compliance with the station design manual and/or varying degrees of incompatibility with current design standards.

The SDM details design and performance requirements for the complete protection system associated with each type of network element. Design standards thus focus on the design of a complete protection system, including X, Y and backup protection schemes, as well as primary plant control and monitoring schemes, required for use in each type of network application (i.e. each piece of primary equipment). Proactive replacement activities (refer Section 5.3) thus involve replacement of consolidated protection and control systems, rather than isolated protection scheme/device replacements. This minimises the cost of design, maximises compliance of the replacement system with design standards and maximises the efficiency and realised benefits of the capital replacement activity.

5.2 Scheduled Periodic Inspection and Maintenance

Protection and control assets are maintained in accordance with PGI 02-01-02 and SPP 02-00-01. Regular inspection, testing and maintenance facilitate timely diagnosis of asset failures with the potential to lead to spurious operation, system unavailability or other operational instability.

Maintenance regimes applicable to protection and control relays are current under review to ensure that the maintenance program achieves an appropriate balance between operational efficiency and asset risk.

5.3 Proactive Asset Renewal and Spare and Obsolescence Management

Strategic asset renewal, spare and obsolescence management ensures that in-service assets are associated with a level of operability and maintainability sufficient to

- Minimise the potential for failures associated with human error
- Optimise the efficiency of fault response and investigation activities
- Minimise time and cost associated with failed asset repair or replacement

Secondary benefits of strategic asset renewal include:

- Facilitate progressive migration towards technologies with improved self-monitoring, alarm and diagnostic capabilities, that maximises the capability to detect, isolate and repair asset failures before they can affect operation of the primary network;
- Provide opportunities to modernise and enhance the capabilities of the electricity network, including enhancing capabilities for the “smart” and efficient control, monitoring, maintenance and management of primary network equipment;
- Provide a mechanism for generating spares for assets no longer available for purchase, but for which short-term retirement of the entire fleet is considered impracticable or uneconomic.

Asset renewal is considered, in accordance with legislated obligations discussed in Section 5.1when alternative risk management approaches (5.1, 5.2) are uneconomic, impractical or insufficient to satisfactorily maintain or reduce network risk. The renewal program proposed for the 2022-27 regulatory period, and the options considered in the development of this program, is described in Section 5.1.

As discussed in Section 5.1, proactive replacement activities involve replacement of consolidated protection and control systems, rather than isolated protection schemes/devices. Thus, multiple assets are replaced under each proactive replacement activity. Individual relays are replaced independently only upon failure.

Similarly, the most appropriate, efficient and economic option when upgrading SCADA services to terminal stations from C50 and RTU50-type RTUs is to replace the entire remote terminal unit, including station HMI, rather than maintain multiple units in service.

5.4 Option Analysis

Options analysis is performed to determine where asset renewal may be considered necessary, prudent or of more economic advantage than alternative risk management strategies. The overall aim of any proactive capital activity is to maintain or minimise risk associated with poor condition or restricted capability assets.

Primary asset renewal projects often necessitate secondary asset reconfiguration, replacement or upgrade. It is most efficient to co-ordinate the replacement of primary and secondary assets whenever possible. An over-arching strategy for protection and control equipment is to complete secondary asset renewals coincident with primary asset renewal, refurbishment or augmentation works as far as practicable in order to realise capital and operational efficiencies and minimise network disruption.

5.5 Option Analysis – Protection and Control Relays

A two-step approach was applied in development of the options analysis for 2022-27 CAPEX forecast:

- A semi-quantitative risk-based decision matrix was used to identify and prioritise the poorest condition, highest criticality assets likely to benefit from replacement
- An economic assessment was applied to the identified poor condition, high criticality assets to test economic viability of asset replacement during the 2022-2027 regulatory period

Only those assets located at stations at which no significant primary asset renewal or augmentation works are anticipated to occur before 2027 were assessed for inclusion in the independent protection and control asset renewal program for the 2022-27 regulatory period.

5.5.1 Identification and Prioritisation of Assets for Renewal

Each asset was associated with a base potential value of unserved energy determined by the criticality of primary equipment it protects (or controls). This value was multiplied by an outage time of (2* $MTTF_{factor}$) hours, where $MTTF_{factor}$ is a weighting on the nominal expected outage time (2 hours) determined by the condition of the secondary asset (Table 4). The result is an estimate of the potential energy at risk in case of spurious operation (3.6.1) or diagnosed asset failure. The condition adjusted potential value of unserved energy, stated in terms of the scheme replacement cost (SRC)[1], formed the vertical axis of the decision matrix.

Table 4 MTTRfactor is determined by asset condition

mttr base	2	hours			
condition	c1	c2	c3	c4	c5
mttr factor	1	1	2	3	6

(A base 2 hour switching time is assumed for all assets in the event of failure)

The horizontal axis of the decision matrix is a rating scale determined by the primary station risk (transformer risk was used as proxy) and the capability and reliability of the associated secondary system. A poor score in the availability consequence rating (4 or 5) applies where a low-availability system with minimal fault diagnostic/analytical capability is applied at a station with high primary asset risk and/or poor primary asset condition. Protection assets in this region of the decision matrix are considered more likely to experience an operational demand while in an unavailable state (failure effect) and thus present an increased safety, environmental and collateral damage risk in case of primary asset failure or network fault.

The applied decision matrix (Table 3) was intended to:

- Facilitate estimation of the optimal time for replacement of poor condition assets based on economic and safety risk
- Economically maximise protection system capability and reliability for high risk and/or poor condition (primary) network assets

[1] The Scheme Replacement Cost (SCR) is the estimated cost of replacement of an isolated protection scheme (i.e. 1 relay and associated peripheral equipment). It should not be confused with the Unit Replacement Cost (URC), which is the estimated cost of replacement of the complete protection and control system associated with a particular piece of primary equipment, including X, Y and back-up protections, as well as any control or on-line monitoring equipment necessary for the application, according to the Station Design Manual.

Table 5 Semi-Quantitative Risk-Based Decision Matrix used to identify and prioritise poor condition, high risk assets for replacement

Risk per Equipment

\ Availability Criticality Spurious Trip \	1	2	3	4	5
5	0	0	6	47	84
4	0	5	36	108	33
3	2	39	27	120	175
2	18	47	103	285	117
1	434	1091	1046	524	277

Maintain
Coincident Replace 10 years
Replace 10 years; Coincident Replace 5 Years
Replace 5 years

A preliminary CAPEX forecast was developed allowing for replacement of all assets identified for replacement within 5 years that are located at stations for which no primary asset renewal or augmentation works are anticipated to occur prior to 2027. Assets identified by condition assessment to be associated with a non-compliance issue were added to the program if not already identified via application of the decision matrix. Asset located at stations where primary asset renewal or augmentation works are anticipated to occur prior to 2027, that were identified for replacement within 5 years, or coincident replacement within 10 years were recommended for inclusion in those planned renewal or augmentation works and excluded from further analysis.

5.5.2 Economic Benefit Analysis

The preliminary CAPEX forecast (from Section 5.5.1) was subject to further analysis to assess economic viability and advantage. The option analysis compared the costs and benefits or protection and control system replacement to the cost of maintaining each of the constituent assets in service. Only failure effect 3.6.1 and 3.6.2 were considered in the economic analysis.

As the preferred approach is to replace complete protection and control systems, rather than individual schemes, the costs and benefits were compared on a program and/or station level, rather than individually by equipment, in consideration of the Unit (System) Replacement Cost (URC)[2] (i.e. the cost of replacement was assessed against the summated benefits of replacement of groups of individual protection and control relays).

[2] As opposed to the Scheme Replacement Cost (SRC), the Unit Replacement Cost (URC) is an estimate of the (direct) cost of proactive replacement of an integrated protection and control system, including X, Y and backup protections, as well as any associated control or monitoring systems necessary for operation of the associated primary plant. The URC allows for replacement of multiple individual devices and associated peripheral equipment, as per Station Design Manual (refer Section **Error! Reference source not found.**).

The preliminary CAPEX program was adjusted in consideration of both the outcome of the economic analysis and the requirements detailed in Section 1.1.1 to achieve the final CAPEX proposal.

5.6 Option Analysis – Remote Terminal Units (RTUs)

A standard economic, cost-benefit options analysis was applied to determine the most appropriate asset management strategy to replace the poorest condition RTUs.

The contribution to station risk by each in service RTU was estimated for the following failure event:

- Failure of a critical alarm point, or failure to diagnose the source of a critical alarm, resulting in a major system incident

5.7 Forecast Summary

The proposed program for the 2022 to 2027 years allows for targeted, proactive and economic replacement of poor condition, high risk protection and control systems under the following activity categories, consistent with legislation and regulatory requirements detailed in Section 1.1.

- Replacement of 220kV and 66kV capacitor bank protection incorporating poor condition static-electronic first-generation microprocessor-based relays (SPAJ140 and SPAJ160C) with Toshiba controller (M40)
- Replacement of obsolete electromechanical relays across various applications, line protection bus zone protection, Circuit Breaker failure protection, transformer protection (CAG34, CAG39, CMU, DSF7, MBCI, CDG11, CDG14)
- Replacement of high risk and poor condition line protection relays (P546 and P544)
- Replacing first generations ABB microprocessor-based relays on transformers protection (RADHD, RADSB) and bus zone (RADSS)
- Replacement of C50 and RTU50 RTU replacement, and some of P3 RTU with Conitel protocol

6 Asset Strategies

6.1 New Assets

- All new and replacement assets will be designed In accordance with the Station Design Maul and current design standards, undertake replacement of complete protection systems (i.e. X, Y, backup and necessary control and monitoring systems) associated with individual items of primary plant/network sections, rather than individual protection schemes/relays
- Replacement activities shall be incorporated within primary plant replacement, station refurbishment or network augmentation activities as far as practicable, in order to maximise operational efficiency and minimise network disruption

6.2 Maintenance and Inspection

- Continue to maintain protection and control assets (including RTUs) as per PGI 02-01-02 and the SPP 02-00-01 suite of documents
- Maintain PGI 02-01-02 and the SPP 02-00-01 suite of documents consistent with the outcomes of ongoing Enhanced Data-Driven Asset Management (EDDAM) studies

6.3 Spares

The use of spare equipment will allow prompt recovery of the transmission network during secondary assets failure.

- Continue to maintain sufficient spares to ensure ongoing maintainability of in-service devices
- Maintain decommissioned assets in appropriate working condition as spares, as required to ensure the ongoing serviceability of in-service, poor condition/obsolete assets pending retirement
- Continue to consider device obsolescence, as advised by asset manufacturers and suppliers, in preparation of asset replacement strategies
- In case where spares for complex equipment are not available, prepare emergency replacement schemes with marked-up drawings and device settings for use during emergencies

6.4 Replacement

- Integrate secondary asset modernisation projects within terminal station rebuilt project or major asset replacement projects whenever economic
- Targeting the protection, control, metering and monitoring asset replacement with the worst asset condition and with the highest risk of failures.
- The replacement of the assets (RTUs) with a SCIMS station architecture incorporating the serial communications to IEDs and a local HMI control allowing retirement of the station mimic panels.

6.5 Condition Monitoring

- Provide condition monitoring to all secondary assets including secondary cabling.
- Review the condition of secondary assets and update the asset management systems as required.

7 Appendix A– Protection and Control Relays Program of Works

Table 6: Protection and Control Relays Program of Works

Protection Relays	No. of Relays
EHV Line Protection	20
Transformer Protection	26
Bus Protection	25
HV Line (Feeder) Protection	24
Cap Bank Protection	20
Circuit Breaker Protection	4

8 Appendix B– Remote Terminal Units Program of Works

Table 7: Remote Terminal Units Program of Works

Location	Type
HOTS	P3
LYPS 500kV Relay House A	C50
Mary St	P3
RCTS	P3 x 2
ROTS 220kV	P3
ROTS OCR Data Centre	RTU50

9 Appendix C– Revenue Metering Program of Works

Table 8: Revenue Metering Program of Works

Location	Number of Meters
WOTS	11
APD	2
RTS	35