Transgrid

People. Power. Possibilities.

Substations Renewal and Maintenance Strategy

AMS Asset Class Strategy

2021/2022

Transgrid

Document Control					
Revision no:	9	**HP TRIM no:**	D2014/18645	**Approval/ Reviewed date:**	30 Nov 2021
Business function:	Strategic Asset Management			**Document type:**	Strategy
Process owner:	Lance Wee – Head of Asset Management				
Authors:	Deepika Parihar, Substations Asset Strategist Sam Murali, Substations Asset Strategist Tim Blair, Substations Asset Strategist Jeremy Culberg, Substations Asset Strategist				
Reviewers:	Evan Lamplough – Substations Asset Manager				
Approver:	Andrew McAlpine – Acting Head of Asset Management				

Table 1: Changes from previous version

Revision no	Approved by	Amendment
6	Lance Wee	2019 update including asset profiles, renewal initiatives and strategies, past performances, future performance targets, formatting and alignment with Network Asset Strategy.
7	Andrew McAlpine	Update to capacitor bank emerging issue tables.
8	Lance Wee	2020 update, including conversion to a new template, SF6 gas inventory, and general update of all figures and trends throughout.
9	Andrew McAlpine	2021 update of all data and strategies including 2023/24 – 2027/28 regulatory period.

A printed copy of this document may not be the current version. Please refer to the Wire to verify the current version.

Executive Summary

Transgrid's substations are made up of assets ranging from low voltage to 500kV. This strategy focuses primarily on high voltage equipment, as well as diesel generators. The assets have been installed over the last 60 years. The ageing asset base and increasing costs required to sustain the equipment are presenting challenges. Asset condition information is being collected to better assess asset health, which in turn informs the repair, replace or refurbish decisions.

Asset Review

Substations are currently located across NSW and ACT. They range in voltage from 500kV to 66kV, with the majority being the 330kV and 132kV network.

Achievements

In FY20/21 Substations achieved significant goals including:

- Continuation of asset replacement programs for the current regulatory period, including circuit breakers, current transformers, voltage transformers and bushings to reduce the risk of failure.
- Updates to health index, bushfire, worker and public safety risk models.
- Initiating various Needs for replacement and refurbishment of substation assets for the next regulatory period.

Challenges

- The average age of assets continues to grow as shown in Figure 37. This puts greater pressure on asset condition data capture and analysis to ensure the continued safety and reliability of the assets.
- COVID-19 has disrupted labour and supply chains, which has had a flow on effect to the delivery of maintenance and replacement programs. This includes repair work on key GIS substations as well as oil containment system remediation work.
- Management of disconnectors and earth switches has on-going challenges due to unavailability of data and large ageing population.
- Higher than anticipated early life component failures in particular models of new circuit breakers requiring development of asset specific strategies

Initiatives

- Improvement of the use of asset failure modes in strategy analysis tools to assist in asset risk modelling and maintenance strategy optimisation.
- Initiate trials of disconnector refurbishment to enable a greater understanding of benefits compared to replacement.
- Investigate new substation technologies, such as hybrid circuit breakers and optical fibre current transformers to remove problematic asset types.
- Commence a program to upgrade substations to Transgrid's revised physical security standard to meet our Network Safety risk obligations.
- Review of regulations and standards application to gas filled HV electrical equipment as pressure vessels and supporting documentation requirements
- Evaluate the trial of online paper moisture monitoring on oil filled transformers for real time monitoring and analytics.
- Initiate trial of substation steelwork replacement to inform the strategy of managing this asset type.
- Develop strategy to support achievement of emissions targets to SF6 management and new technologies

Contents

List of Tables

List of Figures

1. Foreword

1.1. Foreword

This document defines the renewal and maintenance strategies for Transgrid's prescribed Substation assets. In doing this, it applies the overarching Network Asset Strategy, and relevant lifecycle strategies.

The document identifies the emerging issues with Transgrid's substation primary assets, and details the renewal and maintenance initiatives to be implemented in response to these issues. The output of the strategy is the asset management program of works, which is derived via distinct paths as follows:

- The renewal and disposal initiatives are processed through the Prescribed Capital Investment Process, which then leads to the resource-optimised capital works program.
- The maintenance initiatives are implemented via the relevant Maintenance Plan. The maintenance plans are then resource-optimised through Transgrid's Enterprise Resource Planning (ERP) system, Ellipse and supporting applications such as TRAC.

The strategies contained in this document cover the prescribed assets for the five-year period from December 2021.

1.2. Overview

The Transgrid network has been installed over a period of around 60 years, with steady investment through the 1960s to the early 1980s. A second peak occurred in equipment age profiles as a result of the 500 kV ring construction; supply extensions to the city; and replacement programs.

As a result of the progressive installation of network equipment, there is a range of equipment at different points in their lifecycle, ranging from relatively new equipment, through mid-life and on to end of life. During early life, equipment design flaws and issues may become apparent and appropriate responses are developed. In mid-life, equipment issues are fully understood and managed for the best outcome. At end of life, further weaknesses resulting from a long service history become apparent; support may no longer be available (design advice and parts) and the equipment risks are managed until replacement or renewal occurs.

Over the period of construction of the network, manufacturing techniques and equipment technology has evolved affecting the nature of the equipment installed. The rate of change in technology is relatively slow in comparison to computer technology for example, but evolution has occurred to reduce complexity and size of equipment while improving reliability. As a result, there are variations also in the generations of installed equipment over time. From this, the issues affecting the equipment over its life cycle also vary over time.

The rate at which equipment progresses through the life cycle is affected by age, however other factors contribute. These create stress throughout the life of the equipment, such as loading levels, through faults, operation counts, robustness of design and the physical operating environment.

A summary of key issues currently being managed is contained in 3.2 below and concern:

- High risk older plant based on obsolete design approaches.

- The reliability of relatively new GIS equipment at Haymarket and Beaconsfield West;
- End of life considerations for major substation steelwork and for disconnectors and earth switches;

Opportunities are considered and include:

- Implementation of new circuit breaker technology that eliminates SF6 gas, which is a strong greenhouse gas;
- Utilisation of the new generation of protection relays in delivering online condition monitoring;
- Continued use of on line condition monitoring where it is economically justified, to minimise risk, reduce maintenance cost and optimise replacement expenditure;
- Development of relocatable gas sensors for monitoring of severe gas leaks in HV equipment;
- Potential for low power instrument transformers at sites with IEC61850 control systems implemented;
- Partial discharge surveys for substation equipment to identify condition issues;

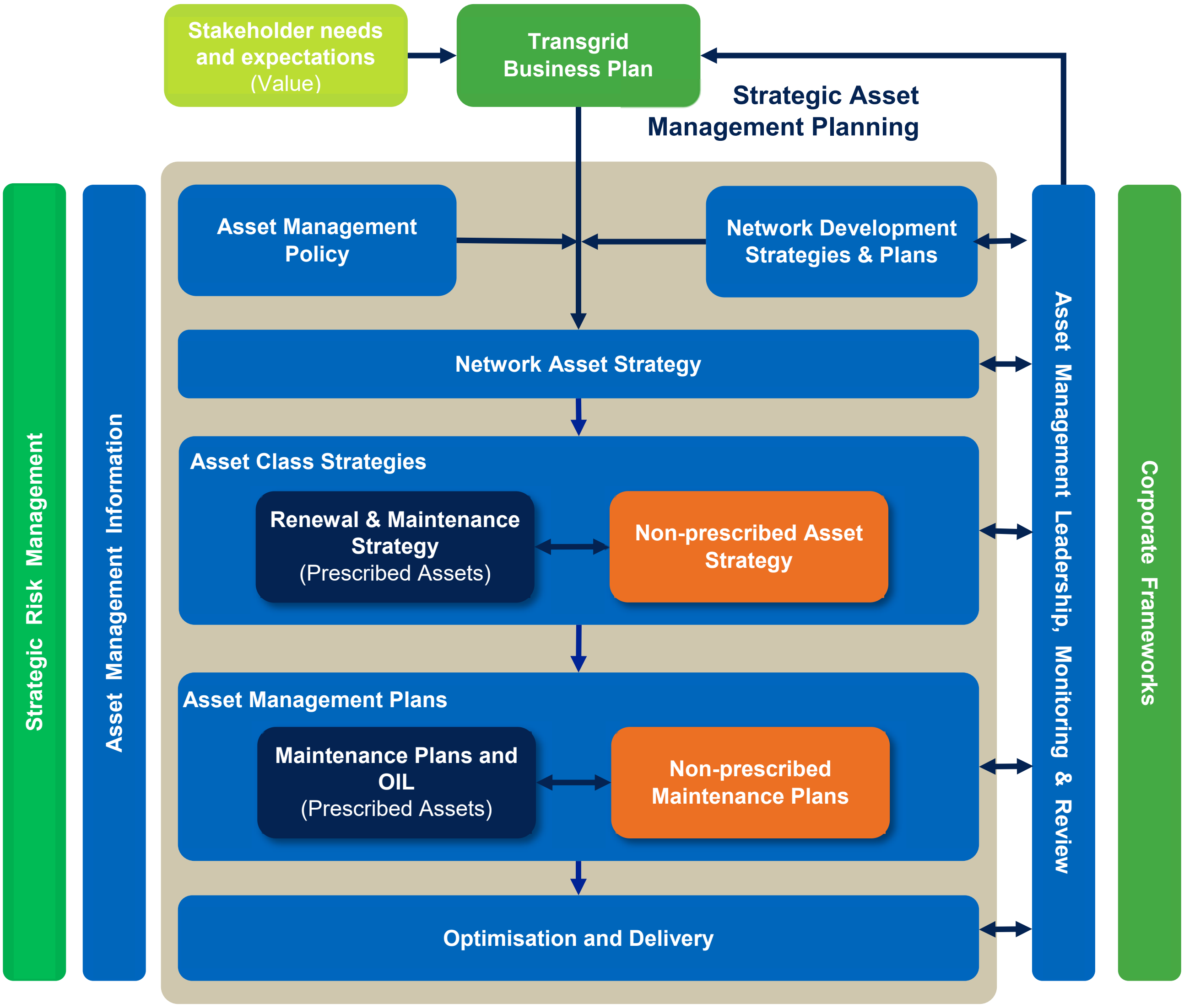
Following analysis, options are developed to manage the overall population to ensure that individual plant failure risks are managed to meet objectives.

2. Context and Background

2.1. Relationship to Asset Management Systems

This Renewal and Maintenance Strategy (RMS) document is one of several that comprise the Asset Class Strategies within Transgrid's Asset Management System. This document sits below the Network Asset Strategy document as shown in Figure 1.

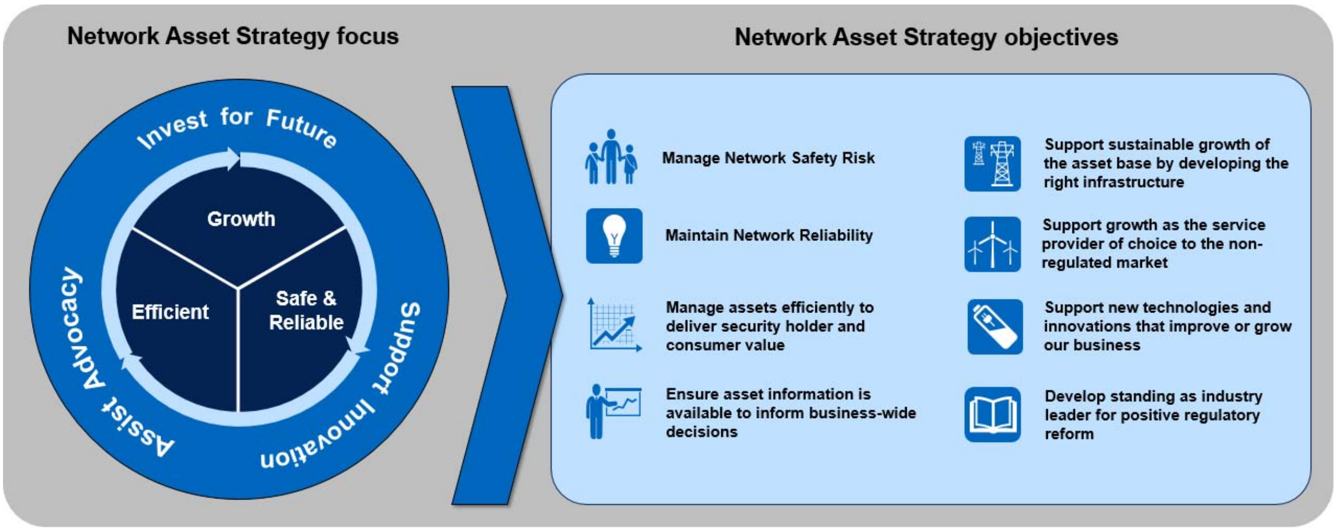
Figure 1: Asset Management System Hierarchy



2.2. Asset Management Line of Sight

The renewal and maintenance strategic initiatives set out in this document support the achievement of the strategies set out in the Network Asset Strategy (NAS) document. The strategic alignment of the initiatives in this document to the NAS is based on meeting its strategic themes. Figure 2 shows the alignment of the NAS to the Asset Strategy Objectives, this RMS shows the actions and initiatives that deliver to these objectives.

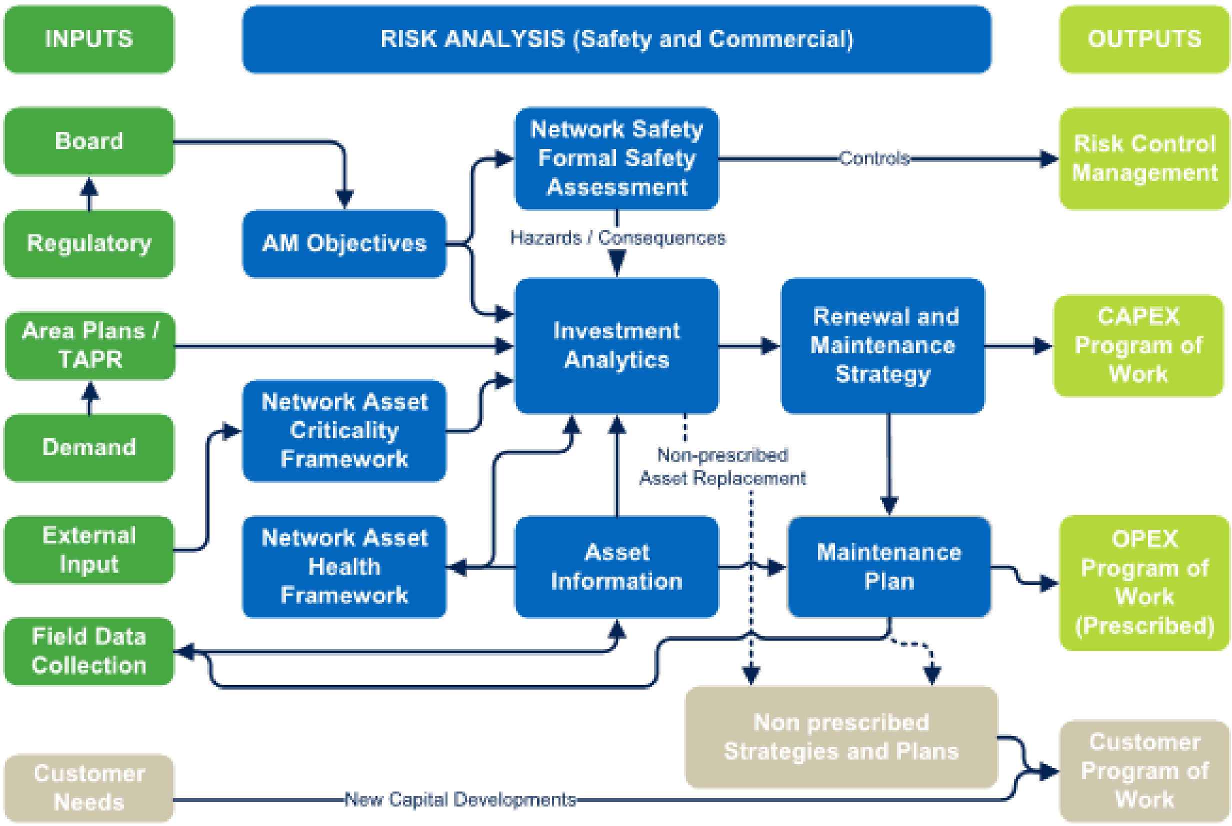
Figure 2: Network Asset Strategy Objectives



2.3. Renewal and Maintenance Process Overview

Figure 3 demonstrates the key inputs that are used to develop the Replacement Capital Expenditure (REPEX) forecast along with input to maintenance plans. Maintenance plan adjustments are optimisations that provide efficiencies in the operating program of work due to a REPEX activity occurring on an asset.

Figure 3: Investment Development Framework



2.4. Asset Overview

2.4.1. Scope of Assets

The detail breakdown of substation assets forming part of this strategy document is provided in Appendix A. The list below provide a high-level summary of the scope of substation assets:

- Primary plant
- Rigid and Flexible busbar and fittings
- Instrument transformers
- Reactive equipment
- Online condition monitoring
- Other ancillary equipment
- Basic site infrastructure
- Footings and Structures

The following assets are outside the scope of this strategy:

- Protection; metering; communication; DC and LV AC supplies; and control and substation systems are not included in the scope of this document – the Renewal and Maintenance Strategy – Substation

Automation Systems and Renewal and Maintenance Strategy – Telecommunications Terminal Equipment documents, cover these.

- Buildings are managed by the 'Asset Manager – Digital Infrastructure' and are excluded from this document.

A breakdown of Substation equipment with an explanation of coverage under this strategy is also included in Appendix A - Substation Asset Breakdown.

2.4.2. Population Review

Transgrid has a total of 95 substations and switching stations (prescribed) within its network ranging in voltage from 500 kV, 330 kV, and 220 kV to 132kV mainly, with some exceptions of 66 and 33kV voltage levels. Their locations vary from coastal to rural, sub-tropical to dry-desert, sea level to high altitude, and corrosive locations to stable atmospheres. Generally, the substations in coastal areas are more prone to accelerated deterioration. Additionally, Transgrid manages non-prescribed substation assets. These assets are not included or discussed in this document.

2.4.3. Asset Base

Each substation or switching station contains a range of different plant and equipment. The substation assets included within the scope of this document are identified in Table 2.

Table 2: Asset Base

Asset	Quantity	Description
Substation sites	95	Transgrid's substations are located throughout NSW, in climates which include coastal to rural, sub-tropical to dry-desert, sea level to high altitude, corrosive locations to stable atmospheres
Power Transformers	215	Power Transformers power range from 30 MVA up to 1200 MVA Power Transformers voltage range from 132kV to 500kV Oil filled and SF6 filled.
Reactors	119	Oil Filled Reactors up to 330kV Air Cored Reactors up to 132kV SF6 Filled Reactors up to 330kV Series and Shunt Arrangement Three Phase and Single Phase
Circuit Breakers	1486	A range of circuit breakers across the network from 11kV up to 500kV. SF6, Small Oil Volume and Vacuum types Live Tank and Dead Tank types
Gas Insulated Switchgear (GIS)	7 Sites	GIS sites ranging from 33kV up to 330kV Several different manufacturers (ABB, Siemens, Alstom)
Instrument Transformers	5815	Current Transformers and Voltage Transformers SF6, Resin and Oil insulated types Voltages ranging from 11kV up to 500kV
Static VAr Compensators (SVC)	5	Located in the northern, central and western parts of NSW.

Asset	Quantity	Description
Shunt Capacitors Bank	116	Shunt Capacitors ranging from 33kV up to 330kV
Surge Arrestors	2232	Zinc oxide types across the network
Online Condition Monitoring	53 Sites	Online condition monitoring (OLCM) deployed across the state for monitoring of transformers, CBs, Instrument Transformers

The nominal lifespan of a substation varies depending upon its individual components, the operational characteristics of the site and the external environment to which it is exposed. The individual components can be broadly categorised as per table 2 above.

2.5. Spares

Spares are held for substation equipment to ensure that failed equipment can be returned to service in an acceptable time frame to minimise the risk of loss of supply. The Spares Policy All Asset Streams (D2017/01712) establishes high-level requirements for spares and considerations that should be taken into account for the development of specific minimum spares holding requirements. The asset class spares plans further refines this requirement:

- Substation Spares Plan (D2006/05490) sets out spares holding requirements based on equipment type and numbers in service.
- In-Service and Spare Power Transformers and Reactors (D2003/2182) sets out minimum spares holding requirement for Power Transformers and Reactors based on population, ratings and strategic locations of the substations.

3. Current Performance

3.1. Review of Previous Renewal, Disposal and Maintenance Strategies

This section discusses the performance of the current asset base.

3.1.1. Historical Expenditure

Historic capital expenditure (CAPEX) and operational expenditure (OPEX) levels are provided in the graphs below. Substations related augmentation expenditure (AUGEX) has increased significantly over the last few financial years, however that expenditure is excluded from the figures below.

Figure 4: Past 5 years REPEX levels for Substations

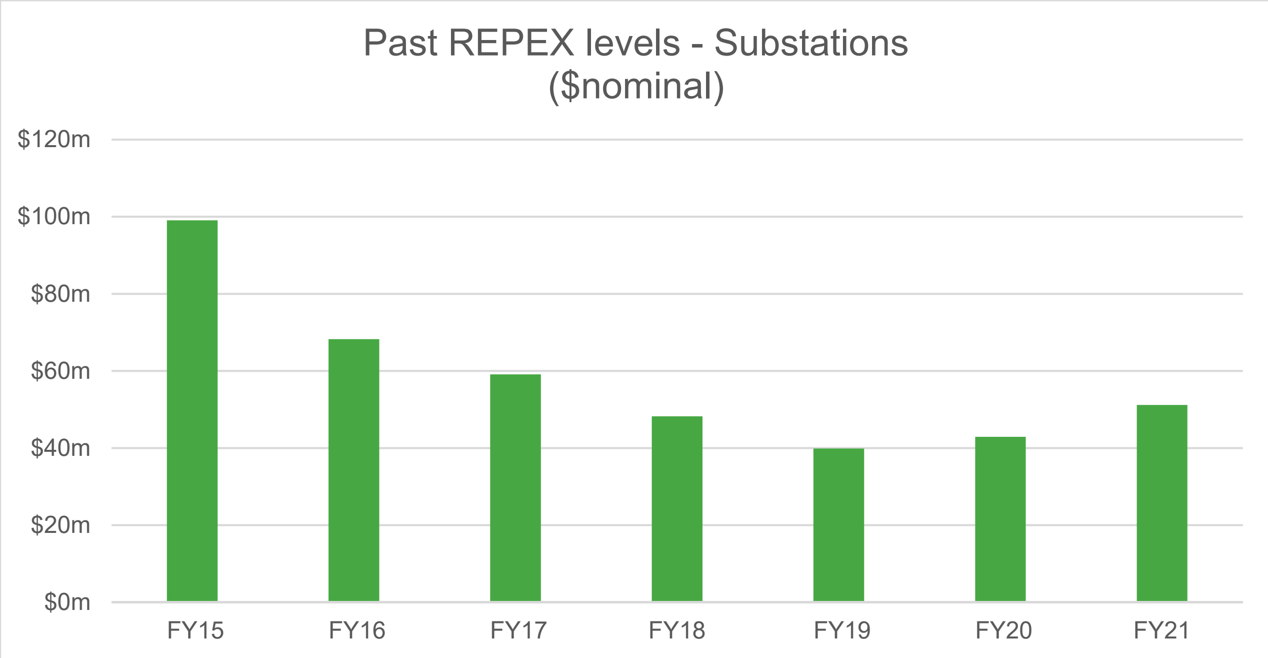
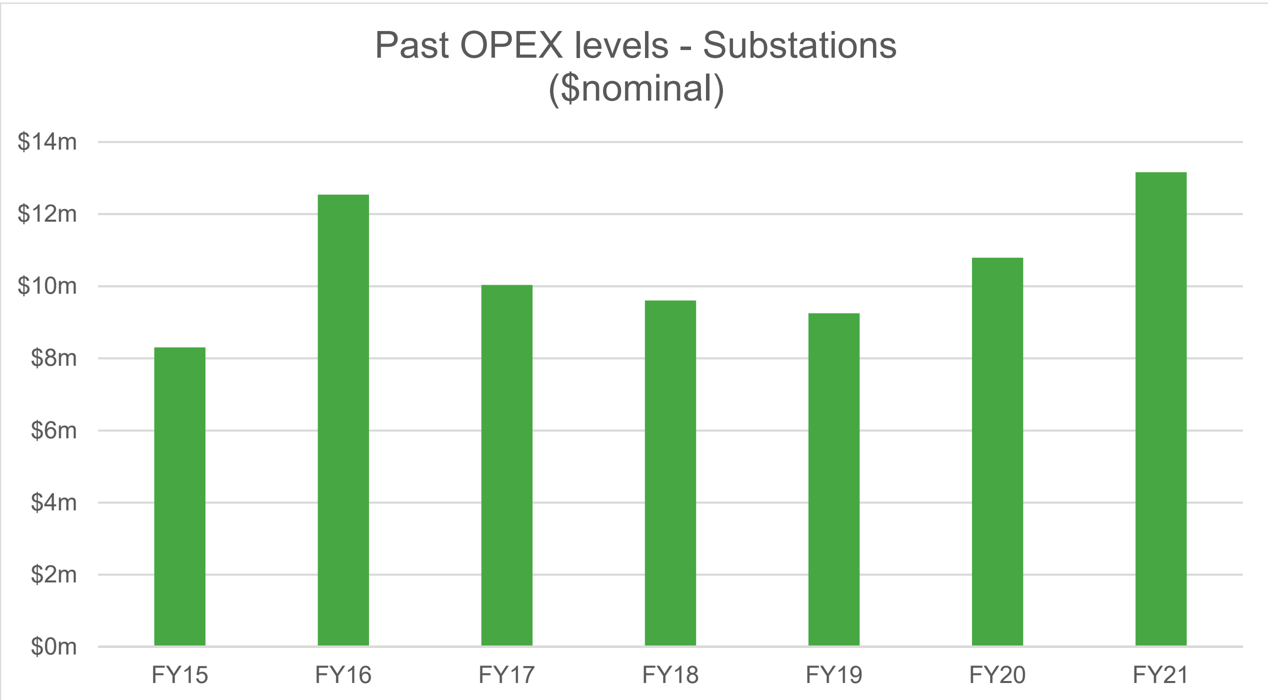


Figure 5: Past 5 years OPEX levels for Substations



3.1.2. Review of Renewal and Maintenance Initiatives

Delivery of the existing Renewal and Maintenance Initiatives has continued to target the replacement of assets assessed to be at risk of failure based on analysis of condition data where:

- The investment can be shown to be in the best interest of consumers
- The investment is required to meet Transgrid's regulatory obligations

The summary of nature of projects in the regulatory period underway is noted below:

- The previously identified substation replacements/reconstructions are being completed and no further candidates have presently been identified justifying this scale of work;
- The current method for assessment of condition and evaluation of replacement developed for major substation equipment has resulted in supplanting of previous replacement programs based on type by replacement programs for a total equipment class (eg: CBs, CTs, VTs).
- A significant steelwork program has been introduced, which will require the development of approaches to implement;
- A transformer and reactor life extension program continues to maximise the lives of the most significant substation assets;
- Apart from these programs, a smaller number of discrete projects have been identified such as transformer and reactor replacements; a switchboard installation at Broken Hill to replace the 22 kV switchyard.

The composition of the Substation REPEX program is largely based on asset replacement programs rather than major projects.

3.1.3. Review of Maintenance Program

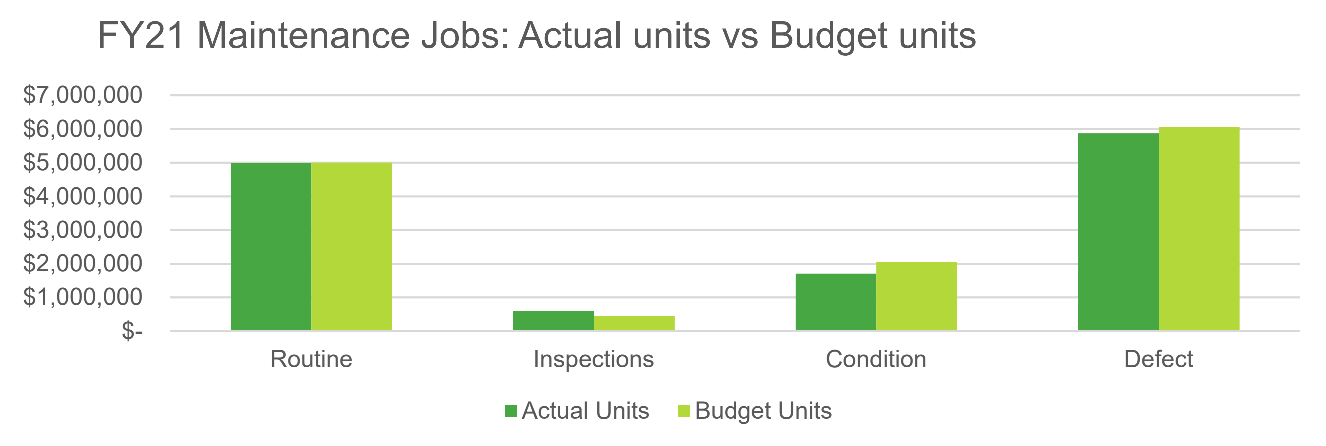
Routine maintenance regimes are reviewed annually and are adjusted to minimise total cost including risk cost. Table 3 below shows the comparison between actual costs versus budget.

Table 3: Substation OPEX FY2021

	Actual $	Budget $	Variance $
Routine Maintenance	4,988,743	5,001,792	(13,049)
Inspections	598,561	442,397	156,164
Condition	1,704,644	2,050,000	(345,356)
Defect	5,869,090	6,050,000	(180,910)
TOTAL	**13,161,037**	**13,544,189**	**(383,152)**

The largest maintenance cost category is defects. There are initiatives by maintenance delivery to improve cost and resource usage efficiency by combining routine or inspections with appropriated amount of defects repair at the same location. Defect spend will also continue to be monitored to determine emerging issues to be addressed.

Figure 6: Substations Maintenance Closed Work Orders in FY2021



Issues with the implementation of maintenance requirements are identified through:

- Overall maintenance performance and maintenance overdue figures;
- Reporting on the completion of AIM scripts;
- Implementation of Control Assurance Reviews (CAR).

Issues and opportunities are addressed using CAMMS, change management processes and substation maintenance working groups.

3.1.3.1. Maintenance Plan Review and Update

Routine maintenance regimes were first established based on manufacturer recommendations, and refined as Transgrid's experience with each asset type has developed through the asset lifecycle. Maintenance is based on inspection and measurement rather than intrusion where possible.

Maintenance Plan update may be required due to:

- Equipment replacements and changes in equipment technology/design;
- New methods of testing or surveillance;
- New trends or indication of failure;
- Re-evaluation of failure risks;
- Consideration of cost and implementation issues.

3.1.4. Past Performance – Asset Management Performance Indicators

The Network Asset Strategy (NAS) was issued in 2019. This document replaced the Asset Management Strategy and Objectives. The KPIs listed below are from the former document. They demonstrate the effectiveness of this Renewal and Maintenance strategy to mitigate the network related safety, reliability environment, financial, compliance and reputational risks in support of the achievement of the asset management targets and objectives are the number of Key Hazardous Events. These measures have been maintained at a low level historically, indicating the Renewal and Maintenance strategies have been effective at mitigating the risks and achieving the asset management objectives.

Historical KPIs and objectives are shown in Table 4 below. Updated Objectives and KPIs are shown in Section 4.

Table 4: Asset management objectives and performance indicators – Substation

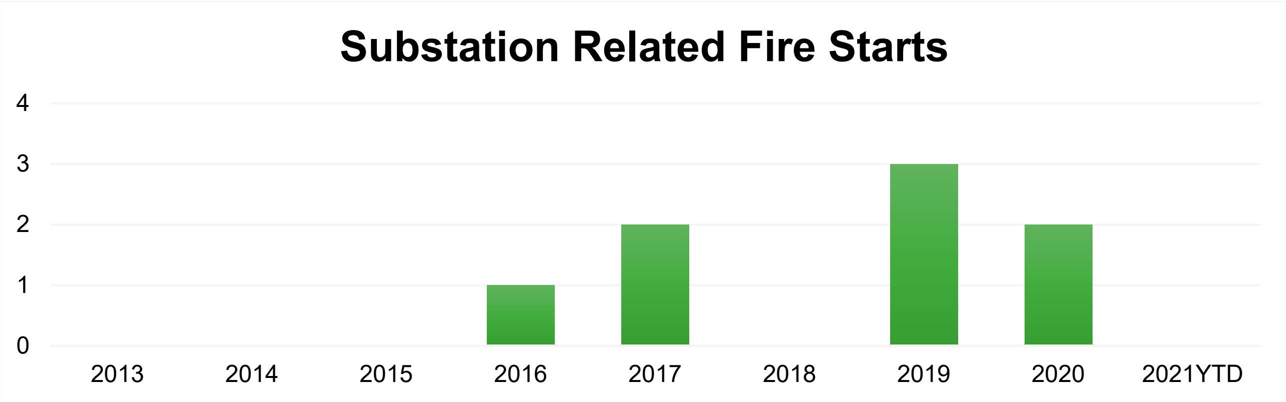
Transgrid Strategic Theme	Asset Management Objective	Asset Management Performance Indicators
• Deliver safe, reliable power	Manage the following network safety risks to ALARP as per Transgrid's Regulatory Obligations and Corporate Risk Appetite Statement • Public Safety • Worker Safety • Bushfire	• Maintain Network Safety LTIs at zero *Achieved in FY2021.* • Maintain 5 year average level of Key Hazardous Events: - Catastrophic Plant Failure - Conductor Drop (within Substation) - Structure Failure (substation gantry) - Uncontrolled discharge of electricity *Refer to the following subsections in 3.1.4.*
• Deliver safe, reliable power	• Minimise environmental harm and property damage	• Maintain 5 year level of substation related environmental incidents Refer to the following subsections in 3.1.4. • No red reports in key result indicators provided to BARC regarding Bushfire, Reliability and Public Safety *Achieved in FY2021.*
• Deliver safe, reliable power	• Maintain network reliability	• Maintain 5 year average level of loss of supply events due to substation faults *Refer to the following subsections in 3.1.4.*
• Deliver safe, reliable power	• Maintain network reliability	• Achieve CY2021 STPIS result of $5.3m *STPIS performance is forecast to meet target.*
• Create an efficient high performing business	• Manage assets efficiently to deliver security holder and consumer value	• 7.8% reduction in AMPoW delivery FY2021 *AMWP budget outcome was met in FY2021. For asset class specific performance see Section 3.1.1.* • Achieve efficiency on regulated capital spend FY2021

Transgrid Strategic Theme	Asset Management Objective	Asset Management Performance Indicators
		The targeted capital efficiency was achieved in FY2021 and reinvested into the business.

3.1.4.1. Past Performance – Substation Related Fire Starts

Substation related fire starts are shown in Figure 7. These events are typically equipment flashover failures which result in fire in the associated equipment and contained within the switchyard.

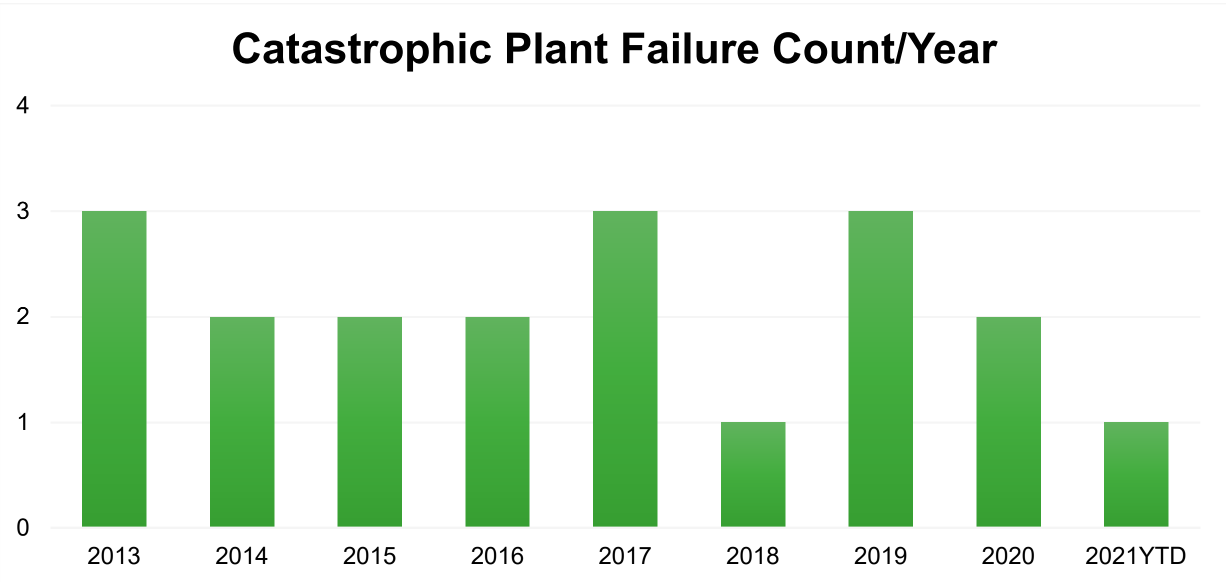
Figure 7: Past Substations Equipment Caused Fire Starts



Substation fire starts have increased since 2016 with exception of year 2018. There were no reported fire starts in 2021.

3.1.4.2. Past Performance – Catastrophic Substation Plant Failures

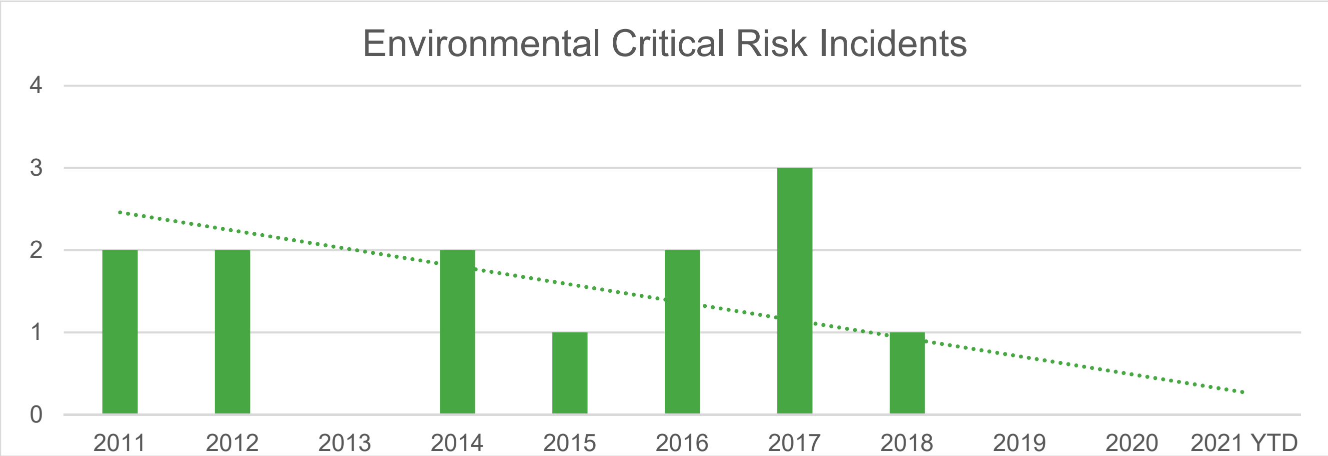
Figure 8: Past Substations Equipment Caused Catastrophic Plant Failure



Substation catastrophic plant failures have been averaging about 2 events per year. There has been one failure in 2021, where a surge arrestor failed catastrophically at Eraring substation.

3.1.4.3. Past Performance – Substation Related Environmental Critical Risk Incidents

Figure 9: Past Substations Equipment Caused Environmental Critical Risk Incidents



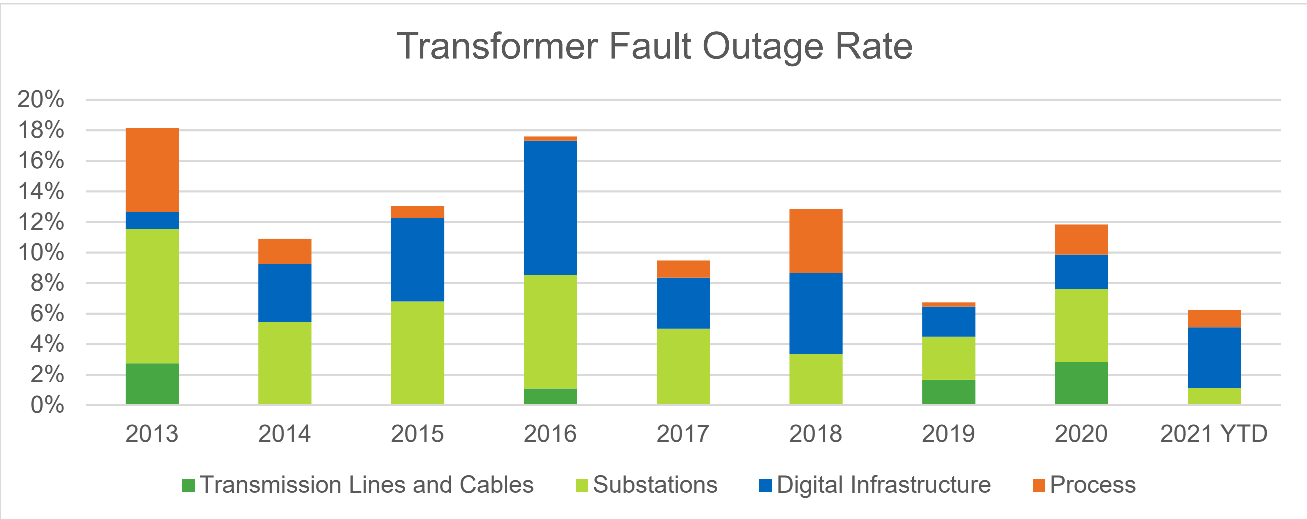
Substation environmental critical risk incidents have declined after three incidents in 2017 and there have been no incidents in 2021.

3.1.4.4. Past Performance – Fault Outage Rates

When the AER refers to "fault outage", they are essentially referring to what Transgrid consider a "forced outage". These events *include outages from all causes including emergency events and extreme events*.

The past transformer fault outage rate categorised by causes is shown in Figure 10.

Figure 10: Past Transformer Fault Outage Rates



The fault outages in 2021 are primarily due to the following:

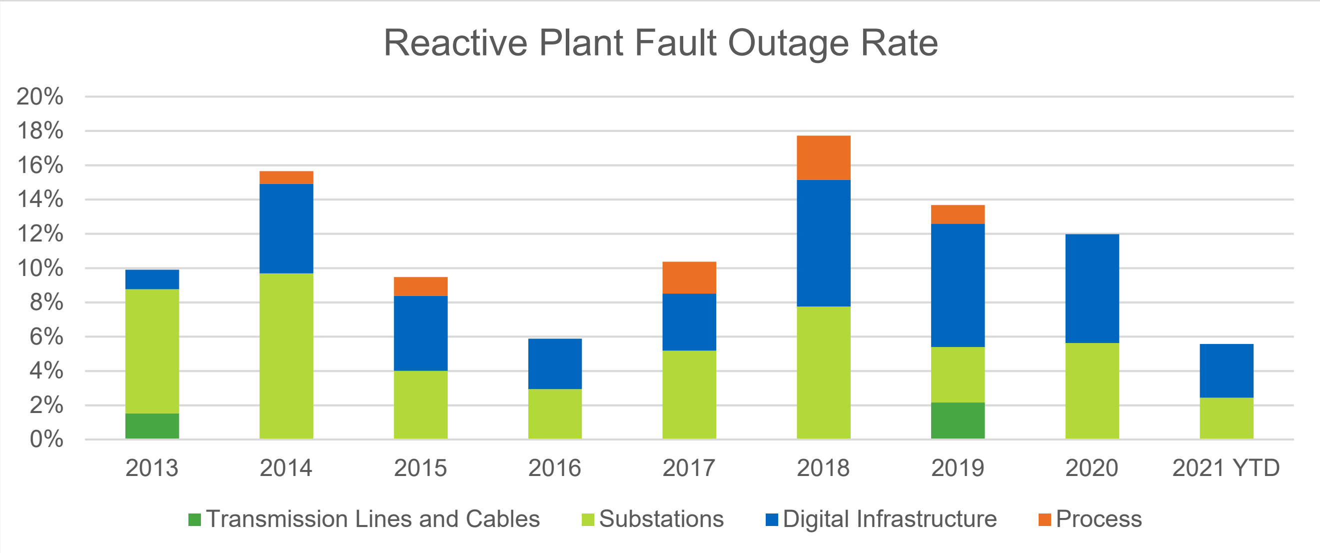
- There were two process related outages. The first was due to staff not following warning signs when manually operating pumps. The other outage was due to mal-operation of the transformer protective device as a result of loose connections.

- The Taree No.2 transformer tripped during a tap change, the online tap changer (OLTC) Buchholz relay operated due to a failure of the tap changer mechanism. The transformer was returned to service on fixed tap and repaired.
- Moisture ingress and contamination inside the OLTC Buchholz caused the Taree No.3 transformer to trip. This has been a common occurrence in recent years on several transformers. An IWR will be issued to investigate protective devices on transformers that are susceptible to nuisance trips.

Work practices related events have been discussed in the working group meeting and reported in CAMMS. There are ongoing discussions with maintenance programs to review and address outages from moisture ingress in transformer protective devices and work practices related events.

The past reactive plant fault outage rate categorised by causes is shown in Figure 11.

Figure 11: Past Reactive Plant Fault Outage Rates



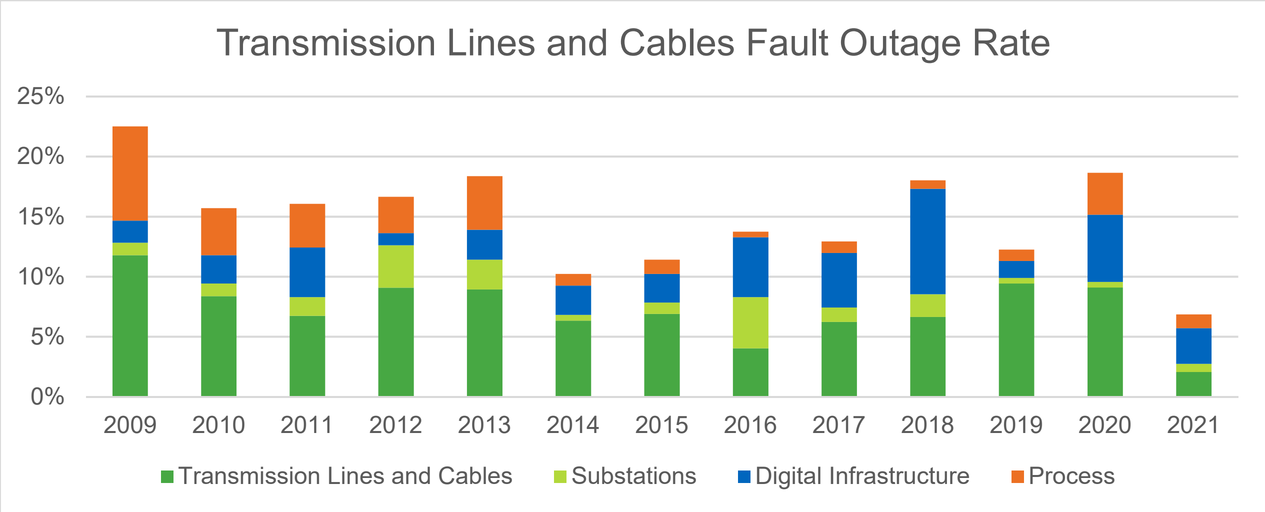
The fault outages in 2021 are primarily due to the following:

- One reactor fault outage event occurred at Murray Substation which involved a circuit breaker tripping after closing. Site investigations could not identify the cause and the circuit breaker subsequently closed without fault.
- One of the Broken Hill SVCs tripped due to a bird strike. Enhancement to the vermin proofing at Broken Hill is being considered.
- The Beryl capacitor bank tripped, and is still under investigation.
- The Tomago capacitor bank tripped due to high pollution, which is a known issue at this site.

The past reactive plant fault outage rate categorised by causes is shown in Figure 12.

.

Figure 12: Past Transmission Lines and Cables Fault Outage Rates



One transmission line fault outage is attributable to substations assets and was caused by a circuit breaker. The circuit breaker tripped after a worker at site inserted ducting into the control cabinet and closed the door. No condition issues could be identified with the circuit breaker during subsequent investigations.

3.1.4.5. Past Performance – Forced Outage Rates

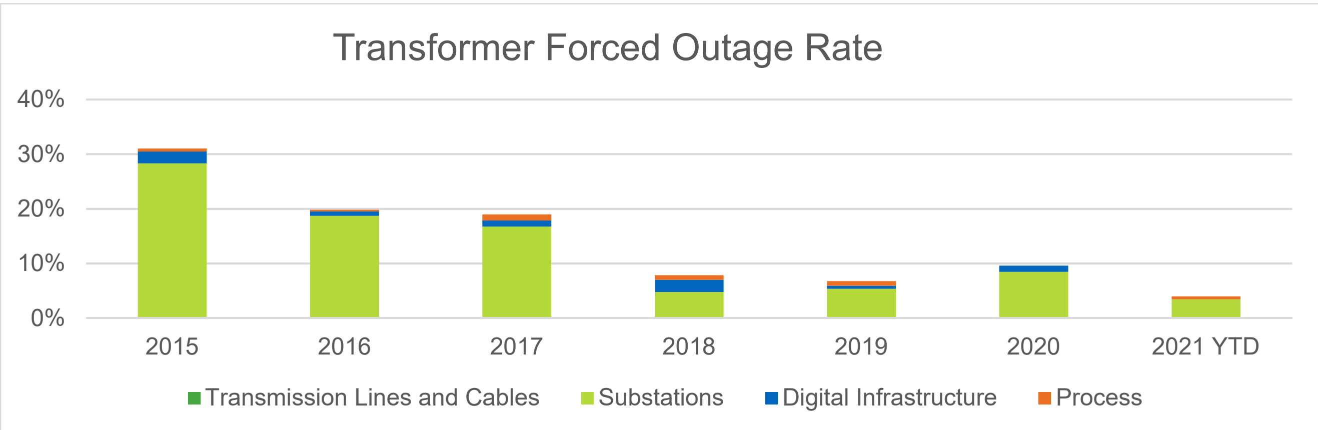
When the AER refers to “forced outage” they are essentially referring to what Transgrid considers an “emergency outage”. The AER definition of “forced outage” is as follows:

> *Forced outage means the urgent and unplanned reduction in the availability of defined circuits that occurs as a necessary consequence of the identification of the actual or imminent occurrence of an event that poses, or has the potential to pose, an immediate threat to the safety of persons, hazard to any equipment or property or a threat to power system security.*

The past transformer forced outage rate categorised by causes is shown in

The transformer forced outage has risen slightly from the previous financial year.

Figure 13 Past Transformer Forced Outage Rates

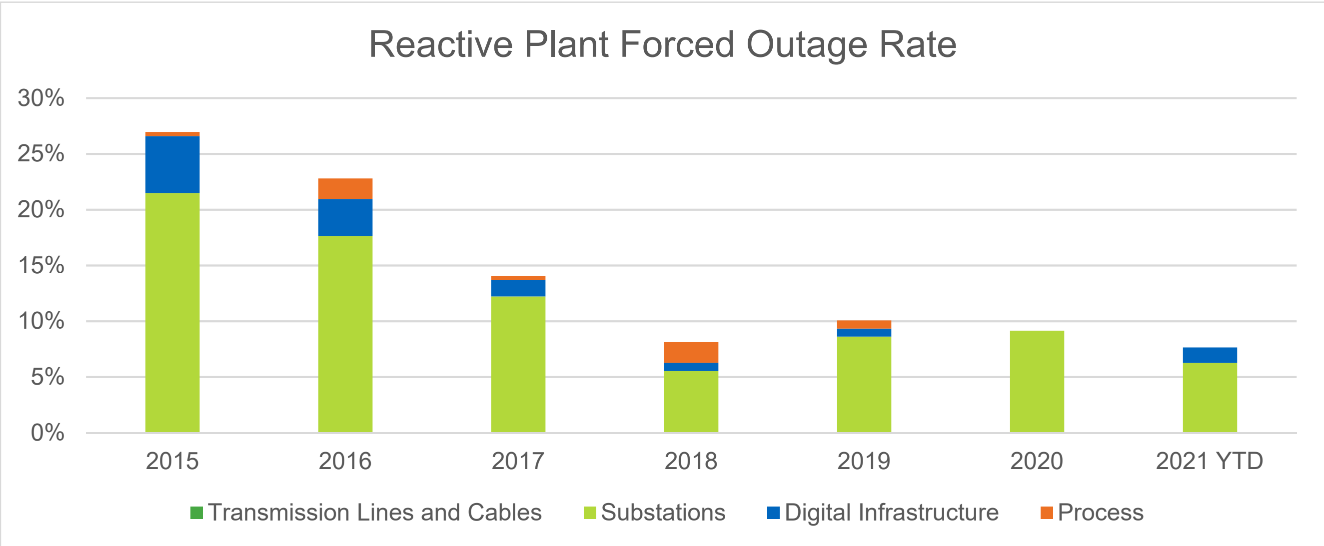


There has been a small decrease in forced outages from 2020. The outages in 2021 are summarised below:

- There were two events due to SF6 top ups for circuit breakers which is expected based on historic trends and are managed under normal leak processes.
- The cooling system leaks on the Sydney North transformer resulted in two forced outages.
  - An interim solution was deployed during the first outage to rectify the leak and restore the transformer back to service.
  - The second outage was taken as the interim solution failed. The transformer has remained out of service with the cooling system disconnected awaiting permanent repair.
- The Murray transformer was removed from service due to poor bushing results post a condition assessment review. The transformer was rested and has been placed back into service with bushing online condition monitoring.
- The neutral connection of the Nambucca transformer was not solidly connected to earth and was burning, the transformer was removed from service and the earth connection was repaired.

The past reactive plant forced outage rate categorised by causes is shown in Figure 14.

Figure 14: Past Reactive Plant Forced Outage Rates



Circuit breaker defects due to SF_6 leaks are a key contributor to the number of forced outages in 2021. SF6 leaks are expected to occur across the asset fleet and may result in outage events, depending on the Network Operations' assessment of the urgency. The following leaks have occurred in 2021:

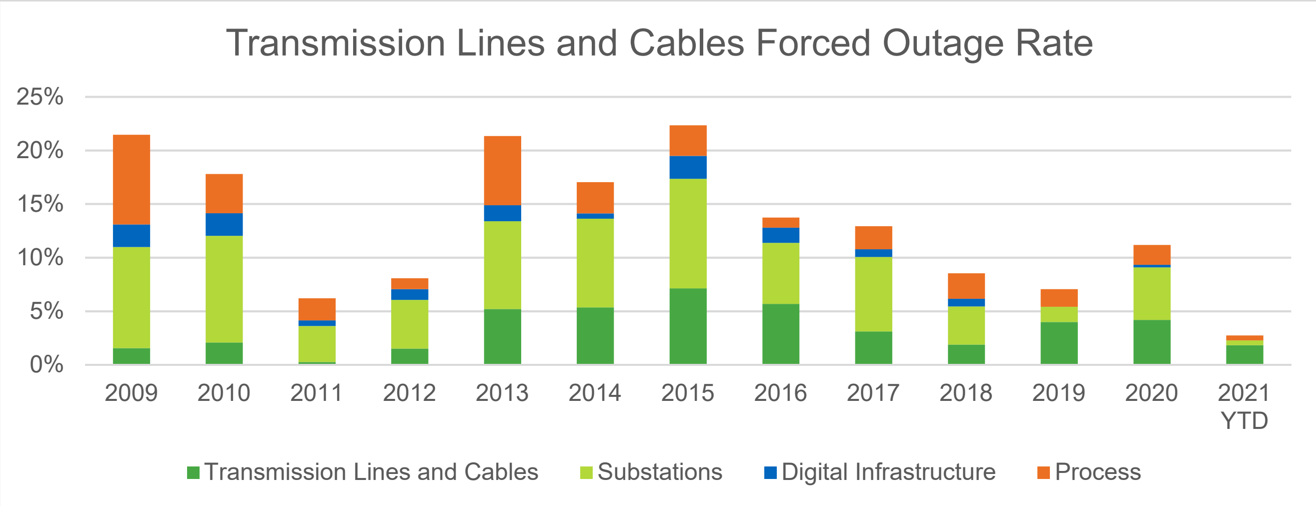
- 5 of the 6 leaks were from a single circuit breaker with a leaking SF_6 gauge which is now repaired. The leak developed into a rapid leak with 4 forced outages occurring in a 25 day period, concluding with the final repair.
- The remaining leak was from a separate circuit breaker, which has been repaired under the normal leak management processes.

Three reactive plant forced outages occurred that were not caused by SF_6 leaks and are summarised below:

- Two circuit breaker outages arose from component failures within the control cubicle including an electronic relay failure and a spring charge motor failure. Both have been repaired through normal corrective maintenance processes.
- The Wellington No.2 reactor's bushing OLCM detected out of tolerance bushings, which resulted in a forced outage. The OLCM device was found to be faulty and there were no issues with the bushings, the device was repaired and reactor was returned to service.

The past reactive plant forced outage rate categorised by causes is shown in Figure 15.

Figure 15: Past Transmission Forced Outage Rates



The one transmission line forced outage attributable to substation assets was due to a circuit breaker SF6 leak, which is in the process of being repaired.

3.1.4.6. Past Performance – Energy Not Supplied (ENS)

Previous ENS events are shown in Figure 16 and Figure 17. There have been no energy no supplied events in 2021.

Figure 16: Past ENS greater than 0.05 System Minute Event Count

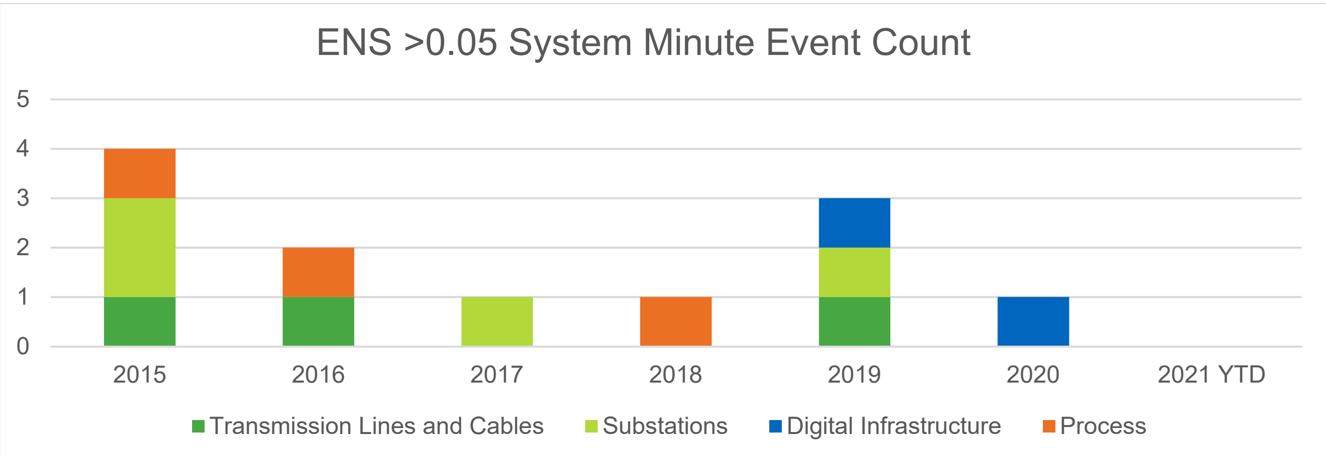
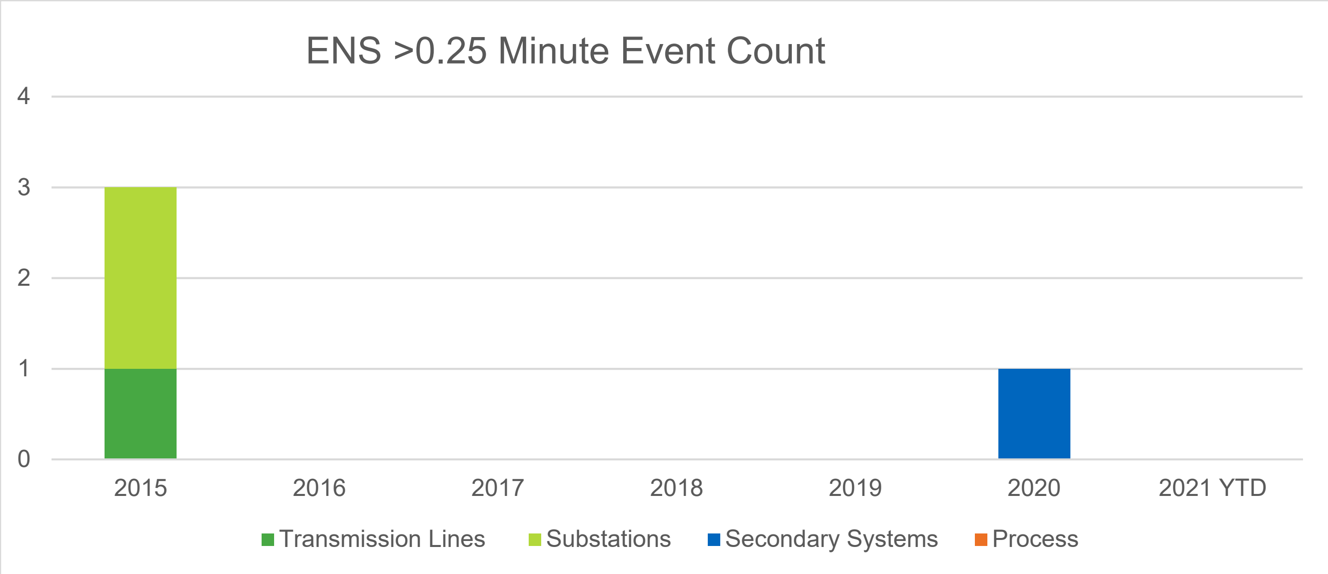


Figure 17: Past ENS greater than 0.25 System Minute Event Count

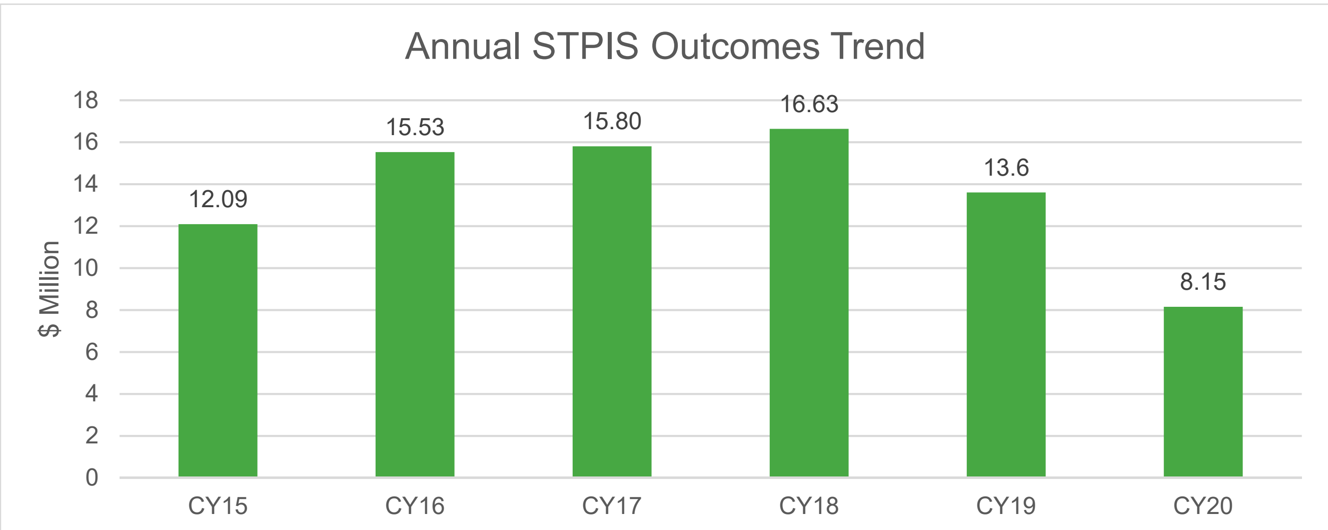


3.1.5. STPIS Performance

STPIS performance in CY20 was lower than previous years but aligned with strategic targets. This was due to many outages associated with upgrading numerous lines and substations associated with QNI. This was an expected result due to the large amount of critical work which needed to be completed. The effectiveness of our Asset Management program has contributed to STPIS performance by:

- Strategically targeted asset replacement programs for defective components of substation equipment, transmission lines, and digital infrastructure to improve asset reliability.
- Improved monitoring of assets and incident response by Asset Monitoring Centre and coordination with network planning for outage management.
- Maximising value achieved from Capital and Operating investment in our assets and minimising outages incurred.

Figure 18: Annual STPIS Outcomes



3.2. Review of Strategic Initiatives

The status of relevant strategic initiatives from the Network Asset Strategy and other asset class specific strategic initiatives is provided in Table 5.

Table 5: Strategic Initiative Status

Network Asset Strategy Objectives	Initiatives / Reference	Status
Deliver safe reliable power		
Manage network safety risk	Refer to Section 5 for detailed asset specific initiatives and status.	
Maintain network Reliability	Investigate the use of corona discharge detection technology and partial discharge testing technology to detect potential failures and avoid catastrophic failure.	In progress
	Review and revise Risk Assessment Methodology and Asset Criticality assessment to ensure our ability to demonstrate that network safety risk is managed ALARP on a data driven basis.	The Risk Assessment Methodology has been updated to match current Business As Usual processes.
Create an efficient high performing business		
Ensure asset information is available to inform business-wide decisions	Continued collection of detailed asset condition data in AIM. Ready access to this data and integrating into the AAIT should empower the Asset Manager to make informed decisions. Improve asset performance monitoring through defect and AIM issue dashboards and analysis to inform asset strategies. Utilise newly implemented failure coding in AIM to allow better analysis and decision making.	Ongoing
Manage assets efficiently to deliver security holder and consumer value.	Work with all Asset Management stakeholders (procurement, human resources, Delivery, Strategy, Finance, and LGR) to identify inefficiencies created by lack of information and close these gaps in collaboration with information systems.	EAM project is in progress with system integration a core requirement.
Invest in Transmission to support the energy transition		
Support sustainable growth of the asset base by developing the right infrastructure	Supporting the development of the Integrated System Plan and Renewable Energy Zone projects.	Ongoing - providing trusted advice for the development, procurement and design of new assets to achieve lowest lifecycle cost.

Network Asset Strategy Objectives	Initiatives / Reference	Status
		Review and update of transmission design and construction standards for the major projects.
Support new innovations and technologies		
Leverage AM to support new technologies that improve or grow our business	Investigate utilising drones for gantry steelwork inspections, thus negating the need to have plant out of service for the inspection.	In progress
	Develop strategies to support achievement of emissions targets to SF6 management and new technologies	Initial emission forecasting developed. Other work to be initiated.

3.3. Asset Review

A list of some of the major issues affecting substations are listed below, with further detail provided in their respective sections:

- With the installation of GIS at four sites since 2004 some immediate emerging issues have recently arisen for GIS assets:
  - Cracking barrier boards in the 132 kV gas insulated switchgear (GIS) at Haymarket Substation.
  - The 132 kV gas insulated line (GIL) at Beaconsfield West Substation has experienced numerous leaks.
  - Transgrid are working with the manufacturers to repair and determine the root cause of these issues.
- Management of disconnectors is an ongoing issue. The management strategy for these devices is developed with inclusion of refurbishment as alternative approach. Some type and site specific refurbishment works are under progress.
- Steelwork corrosion has been recognised as important consideration for some older sites with a corrosive environment. Projects have been initiated to replace or refurbish major steel and the effectiveness of the approach will need to be monitored.
- Older oil filled porcelain CTs with hairpin construction continue to be an area of focus for management of risk to ensure management through appropriate maintenance frequencies and renewal programs.
- There is a large population of substation plant in varying condition and this is changing over time. There is an ongoing ‘generation’ of additional risk arising from increasing failure rates. This is managed through assessment of condition, evaluation of failure risk using consequence and failure risk to determine replacement programs.
- Circuit breakers on 33 kV shunt reactors connected to the tertiaries of 500 kV transformer are subject to very onerous switching duty. Explosive failures have occurred in the past.

- Air core reactors (shunt reactors or associated with capacitor banks) have an increasing rate of failure, and typically result in a fire. A long term strategy for their management is being developed, while in the short term failed reactors are replaced, and those with evidence of failure are being repaired.

4. Strategy

4.1. Strategy and Objectives

The Network Asset Strategy document outlines the strategies and objectives to be implemented to achieve Transgrid's business objectives.

All strategic initiatives with respect to Transgrid's Substation assets are outlined in this section, including the renewal and maintenance initiatives that contribute to the asset management program of works. Further details can be found in the relevant Substation Maintenance Plan, and the referenced governance documents.

The current asset management objectives and future key performance indicators are given in the table below.

Table 6 Asset Management Strategies and Objectives

Transgrid Strategic Theme	Asset Management Objective	Asset Management Performance Indicators
Deliver safe, reliable and low cost power	Manage Network Safety Risk	Maintain Network Safety LTIs and Fire starts (bushfire) at zero Maintain 5 year average level of High Potential Incidents (HPI): • Catastrophic Plant Failure • Conductor Drop • Structure Failure • Unauthorised Entry • Uncontrolled discharge of electricity • Third Party Activity resulting in asset damage / public injury No red reports in key result indicators regarding Bushfire, Reliability and Public Safety Principal Risk Dashboards
Deliver safe, reliable and low cost power	Manage Network Safety Risk	Maintain 5 year level of environmental incidents
Deliver safe, reliable and low cost power	Maintain Network Reliability	Maintain 5 year average level of loss of supply events
Deliver safe, reliable and low cost power	Maintain Network Reliability	Target improvements to performance of the STPIS measures

Transgrid Strategic Theme	Asset Management Objective	Asset Management Performance Indicators
Create an efficient high performing business	Manage assets efficiently to deliver security holder and consumer value	Deliver AMPoW within +/- 5% Delivery Capital Program within +/-5% Target capital efficiency improvements

5. Renewal and Maintenance Initiatives

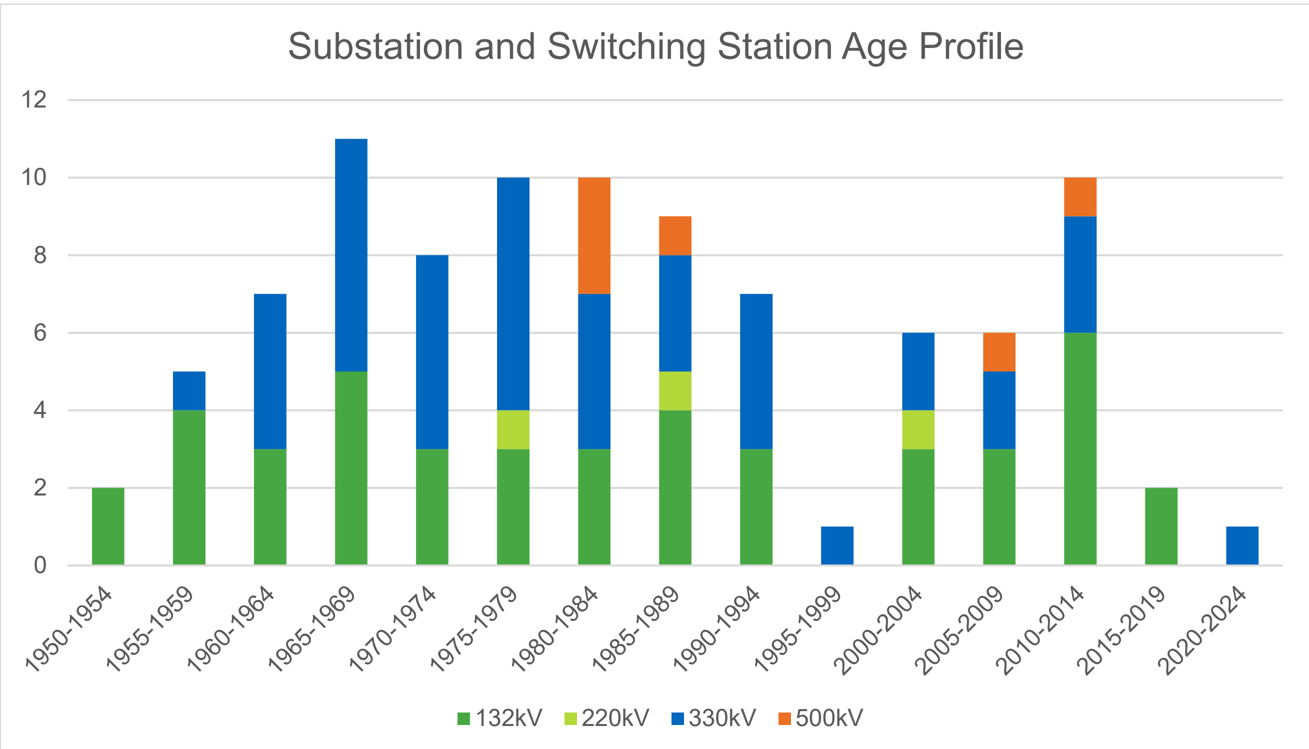
5.1. Substation Site Asset Review

5.1.1. Population Review

Transgrid has a total of 95 substations and switching stations within its network ranging in voltage from 132kV, 220kV, 330kV to 500kV. Their locations vary from coastal to rural, sub-tropical to dry-desert, sea level to high altitude, and corrosive locations to stable atmospheres. Generally, the substations in coastal areas are more prone to accelerated deterioration.

The age profile of Transgrid's substations is illustrated below – where substations are separated by their voltage ranges from 132kV through to 500kV. It can be seen that 27% of Transgrid's substations and switching stations were commissioned before 1970, with the oldest commissioned in 1950 and the most recent in 2020.

Figure 19: Substation and Switching Station Age Profile



Asset health and obsolescence at a total population level is used to determine long-term forecasts of asset replacement requirements and average age. Replacement decisions are based on an evaluation of equipment condition.

Factors that will affect the future substation age profile are as follows:

- Ongoing Piecemeal Replacement:

  Historically Transgrid has managed the end of life of substation equipment through strategic replacement or overhaul (where feasible) of plant items as issues have arisen with their reliability, performance or safety. Individual plant replacement assumes that the underlying infrastructure of a site is in sound condition. For the affected locations, a blend of old and new equipment will result, with the substation infrastructure continuing to age at rates affected by the location.

- Substation Reconstruction:

  A total substation replacement is the preferred option where the asset renewal work scope is substantial enough to yield greater cost efficiencies in project delivery compared to piecemeal replacements. The total site establishment costs are reduced and in addition, larger projects are more amenable to competitive tender. The three general approaches to substation renewal have been identified:

  - Entire substation replacement (could be adjacent, remote or overlapping);
  - Bay-by-bay replacement; and
  - Targeted package of work to address a wider than usual range of key substation issues at a single site in a coordinated way that exploits efficiency of scale.
    - Due to previous asset replacements, the targeted package of work is generally the better option.

- Augmentation:

  A need for network augmentation arises from changes to network demand such as load growth that exceeds the capacity of a substation or elements within it. Network planning developments are considered when renewal initiatives are evaluated, and similarly opportunities to package asset renewal needs are considered during the evaluation of the augmentation need. This can result in the construction of new substations to meet network and load requirements.

  With new capabilities being installed, such as the Sydney West substation grid scale battery, and synchronous condensers (interconnector to South Australia), new strategies for sustaining that capability will need to be developed.

- Negotiated and Unregulated Assets:

  This will result in the construction of new substation bays and in some cases new substations due to new generator, load or other network assets. These sites are not covered under this strategy.

The renewal of substations and substations equipment, together with the creation of new assets will have impacts on the technology installed within the network. Continuous development of high voltage substation equipment and design standards offer improvements to asset performance with the use of state of the art technology available at the time of asset renewal. Improvements include:

- Improved safety performance (e.g. move to polymer insulators)

- Reduced preventative maintenance requirements and costs (e.g. longer maintenance time intervals)
- Reduced capital expenditure and asset risk (e.g. need for separate post CTs removed with integration into dead tank circuit breaker utilising toroidal CTs)
- Increased integration of digital control and monitoring technologies which replace outage based preventative maintenance
- Where substation reconstruction is required in a space constrained location, increased use of compact switchgear (GIS) will be required to achieve reconstruction

5.1.2. Emerging Issues, and Renewal and Maintenance Initiatives – Substation Site

The factors that taken together are significant in determining a need to take broader action at a particular substation site are detailed in each of the substation areas reviewed in the remainder of this document. However, general issues that may have an impact on a decision to reconstruct a substation site are as follows.

5.1.2.1. Compliance Requirements

Substations are designed and constructed to meet the regulatory requirements and design standards that are in effect during the project development and construction phase of the project. Throughout the life of the asset, development of design standards, improvement of work practices and changes to regulatory requirements will result in compliance issues.

Each situation is assessed on its individual circumstances, whether it affects an individual asset or substation, or a group of assets or substations.

The issues that have been identified as potential breach of safety and regulatory compliance requirements are as follows:

- Mobile plant access: Current safe work practices require access using mobile plant (e.g. elevating work platforms, cranes). Early substation designs assume ladder access and allowing for mobile plant access has impacts on bench, drainage design and safe physical access for the mobile plant.
- Cable trench design: Older designs incorporating drainage with the cable trench are prone to cable damage by rodents. Damaged cables represent a risk to staff and network reliability.
- Environmental pollution: Environmental design standards have increased since the construction of many substations requiring improvements to pollution control measures such as oil and noise containment.
- Climate change: In the long term, climate change effects (such as increases in average ambient temperature and flood levels) across will require review to ensure any emerging risks are adequately managed.
- Design clearances: Electrical clearances at some substations are identified as not meeting current design standards. Stage 1 of the low clearance has found 30 of 32 substations which various levels of clearance issues. A capital project to rectify these defects as well as surveying the remaining substations is underway.

5.1.2.2. Asset Health and Obsolescence

Wide spread deterioration of asset health within a Substation is a driver for consideration of a site wide substation renewal initiative such as a substation reconstruction:

- HV assets at a substation will typically decline in condition at a similar rate. Individual assets with poor health have an increased failure risk, which will reduce the reliability of an element within a substation, however wide spread declining asset health across an entire site greatly increases the probability of failure and risk of cascading failures.
- Substation infrastructure is presenting signs of declining condition approaching end of life in the older substation population and includes infrastructure at substation sites where piecemeal asset renewal works have been undertaken. These substation components are more difficult to replace in a piecemeal fashion and have longer asset lives than HV assets.
- The technology used in these substations has also shifted over time and support/expertise may be no longer available.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 7: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Substation Sites Compliance Requirements – Electrical Clearances	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Existing substation assets built to historical design standards may not meet safe approach distances specified in the Power System Safety Rules.	Operational Initiative: Substation Laser Survey of all sites. This initiative is anticipated to generate additional work packages for corrective works as they are identified.	RP2: Stage 1: Defect rectification and Stage 2: Laser survey (underway)	Need No: N2036
Broken Hill 22kV Switchyard	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	A majority of the 22kV switchyard HV assets are identified for replacement through existing and proposed renewal initiatives. A secondary systems renewal has been identified based on declining asset condition at site.	Renewal initiative: Primary and Secondary Systems replacement to be completed addressing the emerging.	RP2 Included in 2018-23 Revenue Reset Submission	Need No: 1193
Yanco 33kV Busbar Clearance	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	The 33 kV bus at Yanco Substation does not meet Transgrid Design Safety Clearances and does not meet clearances required under AS2067 at 33 kV busbar earthing stirrups.	Renewal initiative: Raise the existing busbar Replace Section 2-3 busbar with flexible connections.	Cancelled Include consideration of other mitigations under N2036 (above)	Need No: 1606

5.1.3. Maintenance Program – Substation Sites

Component failure risk analysis is performed on existing equipment to develop a complete maintenance plan in the aim of improving and sustaining the reliability of the asset and the management of asset risk.

The maintenance initiatives directly drive the routine maintenance regimes, which are detailed within the Substation Maintenance Plan. Substation site maintenance is implemented through a series of substation inspections. The inspection schedule is as follows:

- 6 monthly inspections
- 12 monthly inspection with additional checks added
- 12 monthly thermo-vision inspection

Bushfire Inspections are performed in conjunction with annual substation inspections allowing sufficient time for identified defects to be rectified prior to the commencement of the Bushfire Danger Period.

5.1.4. SF6 in Substations Equipment

Transgrid report SF6 data annually to the Clean Energy Regulator under the National Greenhouse Energy Reporting (NGER) scheme on SF6 holding capacity and losses attributable to leaking equipment.

The reports including holding (kg) and losses, typically expressed as % of total holdings. Historical figures reported are included below.

Figure 20: SF6 gas holding in kg

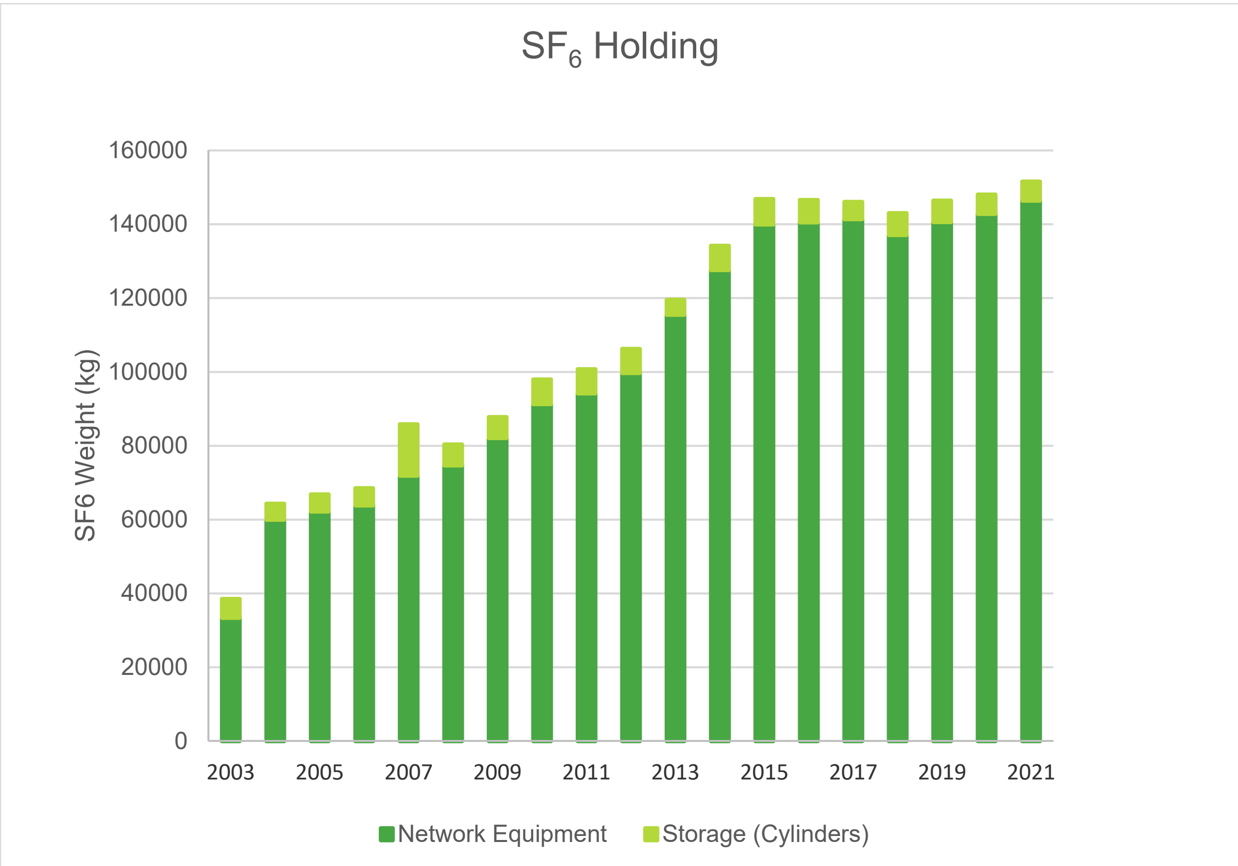
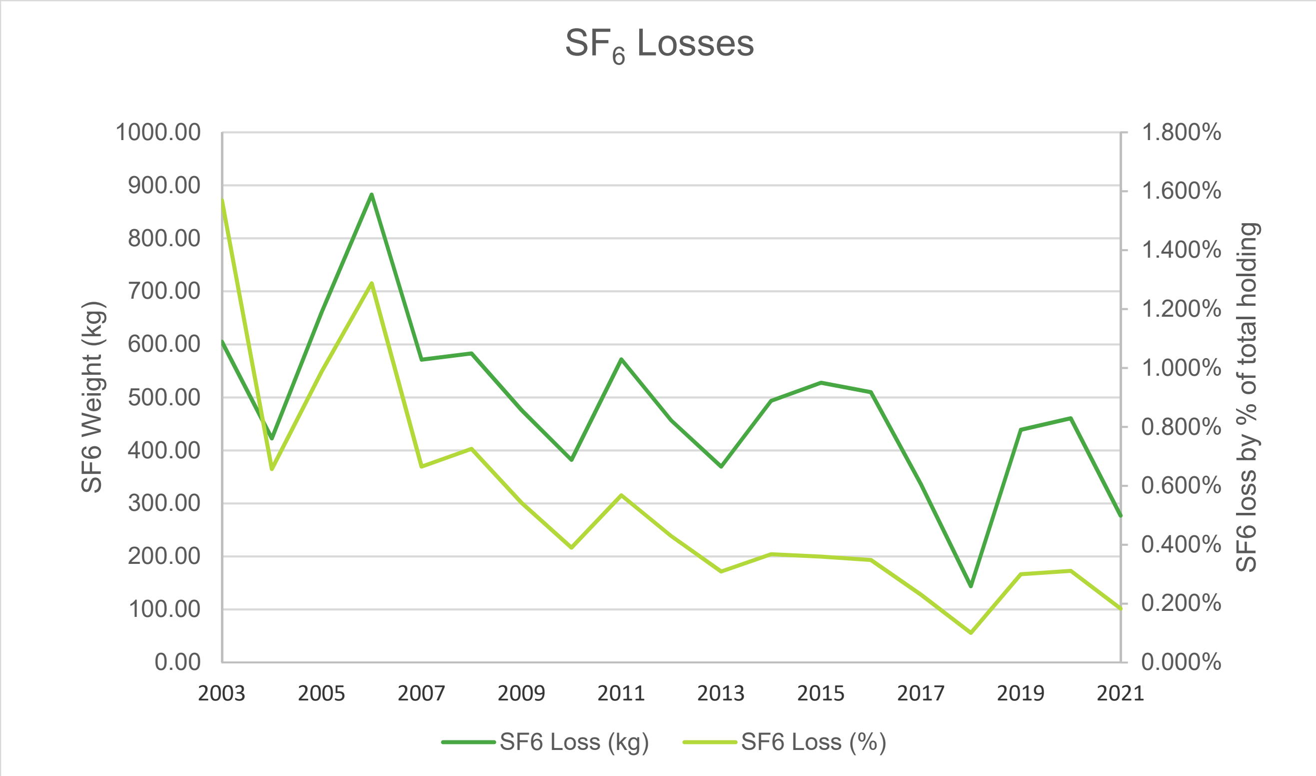


Figure 21: SF6 losses



The data shows a significant improvement in leak rate since the earliest reports in 2003, and has been maintained below 0.4% since 2013.

The improved performance over this timeframe can be attributed to improvements in gas handling work methods, defect management (repairs) and asset renewal strategies addressing problematic assets and models.

5.2. Infrastructure Asset Review

5.2.1. Population Review - Infrastructure

There are ranges of assets forming part of a substation infrastructure that are required to perform well in a successfully functioning substation. This includes:

- Site surrounds (buffer areas, roads etc.)[1]
- Civil infrastructure (major steel, drainage, cable trenches, footings, walls, bench design etc.)
- Buildings and amenities[1]
- AC supplies[1]
- Lighting[1]
- Cabling[1]
- Oil containment and drainage

[1] Refer to the Network Property Renewal and Maintenance Strategy (D2018/02412)

- Earthing systems
- Internal roads
- Fire systems[1.]

The design and condition of the infrastructure required to operate substations varies with the time of its construction and environmental factors.

5.2.2. Emerging Issues, and Renewal and Maintenance Initiatives – Infrastructure

Some aspects of substation infrastructure are covered under the Substation and Radio Repeater Site Facility Assets Renewal and Maintenance Strategy. A summary breakdown is included below and details is provided in Appendix A - Substation Asset Breakdown.

This Document	Substation and Radio Repeater Site Facility Assets Renewal and Maintenance Strategy
Earth grid Footings Substation steel Drainage Oil containment Substation bench Cable trenches	Fence and exterior Security Buildings Building fire protection systems LV supplies Kiosks and boxes Cabling Roads Switchyard fire protection

Significant issues affecting Substation infrastructure are outlined below.

5.2.2.1. Steelwork - Corrosion

Corrosion will become an important issue in substations particularly those located near the coast, industrial areas or inland bodies of water and those built in the 1960's. Surface rust is becoming obvious on galvanised steel surfaces and fasteners (bolts and nuts) are failing progressively. There are cases of localised corrosion – most particularly on gantry and switchgear structure holding down bolts – that if left untreated, will lead to failure of the structure.

Major and minor steelwork supports overhead strain conductors (gantry structures), rigid and flexible busbars, and equipment and plant. Major steel used to support overhead strain conductors and strung busbars are the greatest concern. These cannot easily be treated, painted or replaced due to the outages required to access them. Failure of these structures would have a major impact on the substation and will present unacceptable reliability and safety risks in the longer term.

There are three identified issues affecting substation steel:

- Corrosion at ground level affecting holding down bolts and structure base plates. This can occur due to localised problems including for example: poor grouting materials or application; poor grout in combination with incorrect routing of the earth strap can acerbate corrosion; poor design leading to collection of silt and grit or pooling of water.

- The resulting corrosion will lead to loss of strength and ultimately to failure of major steel structure(s) in a substation. The resulting failure would have major impacts on the substation and is expected to be difficult to repair.
- Corrosion of fasteners may occur in advance of corrosion of steel members in a lattice structure (most sites affected by corrosion have this type of construction). This arises due to way in which nuts and bolts are made. Nuts are pressed and a thread is cut. The galvanising is not as thick as on the steel members forming part of a lattice structure.
- The result is that nuts may 'blow' off ahead of major corrosion of steel members and lose all strength. Replacement is the preferred strategy but this requires a staged approach, favourable weather conditions, bracing, and/or outages.
- Corrosion of the steel members in a lattice structure is a final issue. Lattice structures were specified with a galvanising layer that would permit a life of up to 40 years in a coastal environment. When the galvanising layer has been consumed, the underlying steel will corrode at an increased rate. Erosion of the galvanising layer may not be even across a structure and exposed sections or those with thinner galvanising layers will be affected first.

  Once the galvanising layer has been consumed across a gantry, options to treat are limited. Steel work refurbishment has been trailed at some Transgrid sites. These trails have demonstrated that:

  - Blasting in a live switchyard is inefficient and costly due to outages/system constraints.
  - Garnet overspray requires extensive outages of all nearby high voltage plant.
  - There are safety risks due to blasting steelwork with lead contaminated paint (older sites).

At present, the only cost effective options are to replace the steelwork.

The high cost of replacing the major substation steelwork places a greater emphasis on adequately monitoring the steelwork condition. The data collection requirements of steelwork inspections have been clarified in the Substation Maintenance Plan and further improvements in this process will be implemented.

5.2.2.2. Insulators and Other Fittings

In a similar group of substations, insulator strings used to support overhead strain conductors are often of unknown type, likely of a type already retired from transmission lines due to concerns regarding reliability. This is of less concern in this application because of the much smaller mechanical loads but represents and increased risk factor and may lead to failure with further deterioration.

The above is complicated by corrosion of the pin and sockets of the insulators strings and of other fittings used to attach equipment to steelwork.

Failure of these insulators and fittings will result in safety risks to personnel, extensive outages and damage.

The requirements for the inspection of insulators and fittings is included to ensure the ongoing monitoring of these assets and rectification where required.

5.2.2.3. Switchyard Surface - Grass in Switchyards

A number of substation sites constructed in the 1960s do not have gravelled switchyards and this has the following issues:

- Grass-cutting is necessary and this normally requires that contractors be employed to cut the grass on ride on mowers. This has inherent risks in using contractors with relatively low levels of HV knowledge throughout switchyards. There are (managed) risks to the personnel carrying out the work; and to equipment. A past example has been damage to earth grid straps caused by the mowers.
- Rabbit damage to control cabling has been a serious issue at some sites and it is thought that the presence of grass in the switchyard provides a source of food to sustain even those rabbits trapped inside the switchyard by meshing installed on the substation perimeter to reduce rabbit impact.
- Rabbits can also burrow within grass switchyards which can present a safety hazard for staff onsite. These are managed through the defects process.
- Gravel provides an additional level of safety from step and touch potential risks due to the extra resistive layer that it provides.
- Grass provides a fuel source for bushfires, when compared to gravelled sites. This fuel source is managed through grass cutting.

Where other significant work is planned on a substation with grassed switchyard, conversion of grassed areas to gravelled are included in project planning if feasible.

5.2.2.4. Oil Containment

Oil containment systems in Transgrid's sites are designed in accordance with AS2067 and the normal minimum requirement is the provision of bund drained through a spill oil tank design to retain oil through and 'underflow' drainage system. Secondary containment may be considered where risks are assessed to be high. Where no secondary containment is available, firefighting should not commence on a transformer fire until staff are stationed at outflows.

5.2.2.5. Cable trenches

Older brick type cable trenches also provide subsoil drainage under the cable tray. These trenches have the following issues:

- Deterioration of brickwork mortar and damage from traffic leading to collapse. This may be complicated by plastic/reactive soil types.
- Exposure to cable damage by rodents from below.

At least two major control cable fires with severe impacts on the affected substations have occurred due to a combination of rabbit damage and the routing of large capacity 415 V supplies together with control and protection wiring. Design standards have been altered to require separation of major AC supplies from control and protection cabling.

At older sites, cable trenches are becoming overfull at pinch points such as immediately prior to entry to the control building and at Sydney North, Sydney South and Dapto substations, large cable basements present a point of possible single point failure for the site in the case of a cable fire.

New sites may be constructed using IEC61850, which greatly reduces site cabling and relieves these issues.

5.2.2.6. Earthing Systems

Earth Grid design standards and techniques have matured significantly since the construction of many original sites. A design review is required to be completed 30 years after commissioning, the completion of these surveys is anticipated to identify defects due to insufficient original design and age related deterioration; a package of works will require development to address the identified defects.

Earthing systems on older substation sites can be affected by the following:

- Increased fault level due to additional connections leading to levels beyond the original design fault level
- External influences causing transferred voltages (e.g. fences or pipes being installed in the vicinity of the site)
- Damage to earth grid conductors caused by excavation associated with works on the site.
- A number of 132 kV sites use steel stakes as a component of the earthing system and these may corrode below ground.

5.2.2.7. EMF Performance

Incomplete information exists for EMF performance of older sites. There is no evidence for health impact from the electromagnetic field levels normally experienced in accessible areas of Transgrid's substations; however development of appropriate EMF substation models and analysis may be beneficial.

5.2.2.8. Asbestos

Asbestos surveys have been conducted at all Transgrid substation sites and where possible, the substance has been removed. Some amounts of bonded asbestos remain where it is stable and safe and is not feasible to remove. This is included in a register and is monitored and maintained. Where opportunity arises in major works, the material is removed.

5.2.2.9. Other building and Infrastructure Issues

Each of Transgrid's substations and switching stations include a control room building, which vary in size from a small single-level house sized building to large multi-level establishment. These buildings generally contain a relay room, battery room, communication room, amenities room and workshop. For new installations of secondary equipment, prefabricated buildings have been used to house the control, protection and metering equipment.

Sites also contain fencing, roads, drainage systems, landscaping, environmental buffer zones and other services, which need to be kept in good order.

Current and emerging issues related to substation buildings and site infrastructure include:

- Degradation or ineffective design of drainage systems.
- Degradation of road systems.
- Changed requirements for lighting or deterioration of light fittings.
- Building defects such as roof leaks, footing issues.

Issues with property, buildings and site infrastructure are identified through substation maintenance and inspection activities. Minor issues can be addressed through the defect management system (i.e. defect maintenance).

Building and property issues are included under the Substation and Radio Repeater Site Facility Assets Renewal and Maintenance Strategy.

5.2.2.10. High Voltage Cabling

Switchyard cabling at 66 kV and above is covered in the Cable Renewal and Maintenance Strategy. However, cables from 11 kV up to 66 kV are used in substations to connect auxiliary transformers, to connect capacitor banks and as part of feeder connections.

The older generation of these cables are typically MIND (mass impregnated non draining) paper cables with lead sheathing. The serving on these cables can be deteriorated and sealing end connections may deteriorate due to weather exposure and ageing. Replacement may become necessary for ongoing reliability.

5.2.2.11. Transformer Compound Walls

Transformer compound panel walls are installed around some transformers to reduce sound levels and ensure that fire does not spread between assets. Previous generations of panel fire walls have resulted in some panels being insufficiently secured and has resulted in sections of wall falling down. This results in a safety and reliability risk due to the potential of the panels to strike a person or another asset.

Condition issues may also be identified through routine substation inspections and investigated further to ensure they are addressed as required.

5.2.2.12. Concrete Footings

Concrete footings for substation gantries and switchgear are essential to the essential to the required capacity and function of the asset they support.

The gantry footings at Upper Tumut are subjected to stress due to repeated freezing and thawing due to the local climate. The condition of the footings is deteriorating and there is a risk that the footing will become irreparable.

5.2.2.13. Substation Flood Risk

Previous instances of flooding, or close to flooding, at Transgrid substations indicates a risk of flooding. Flooding of a substation may cause damage to HV and LV assets and have an impact on network reliability. The risk of future floods should be quantified and compared options to reduce the risk.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 8: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Gantry Steelwork, holding down bolts and fasteners: • Sydney East • Sydney North • Sydney South • Albury • Dapto • Tomago • Hume • Wagga 132kV	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	The gantry steelwork at a number of sites are approaching the end of its life based on detailed structural modelling and galvanic thickness. Fasteners are losing strength in increasingly quantities and require replacement The construction of holding down bolt interfacing is leading to corrosion of the bolt and base plate.	The steelwork will be addressed through replacement/refurbishment of steelwork, replacement of fasteners and treatment of holding down bolt and grouting interface. Trials are currently underway to replace the gantries at Sydney South Substation.	RP2 (2018-23) RP3 (2023-28) The following sites have been assessed and will not have work completed in RP2 or RP3: • Sydney North • Tomago • Hume	Need No: 1358 N2485
Upper Tumut Gantry Footings	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	The gantry footings are significantly degraded due to repeated freezing and thawing and potentially inferior construction methods.	The gantry footings will be treated along with the steelwork to ensure sufficient remaining life.	RP2 (2018-23) Complete	Need No: 1358
Earthing Systems	• Manage network safety risk • Maintain network reliability	A number of substations have not had earthing system tested and may have unknown risks due to unsafe Earth Potential Risk (EPR).	Earth grid assessments were completed in RP1 and sites rectified.	Complete	Need No: 1638 IWR0126 1887 1959

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
	• Manage assets efficiently to deliver security holder and consumer value		Earth grid condition assessments were undertaken in FY19 at Regentville and Wagga North Substation as part of major capital works. The assessment identified that the earthing is currently non-compliant. The work at Wagga North is in progress and work at Regentville is now completed. The earth grid condition assessment at Broken Hill identified meshed voltage hazards, similar issues are identified by Essential Energy at their Pinnacle Place substation. On DNSP request earth grid bonding work is being progressed to mitigate risk at both sites.	In Progress (Wagga North) Completed (Regentville) In Progress (Broken Hill)	Need No: N2182 IWR N2092 IWR N2681
Oil Containment System Inspection, Clean Out and Repair	• Manage network safety risk • Manage assets efficiently to deliver security holder and consumer value	The effectiveness of existing oil containment systems may be limited due to significant weed growth in dams or siltation in containment tanks.	Inspections were carried out across 54 sites in FY20 as part of the 10 yearly spill oil tank inspection.	In progress The inspections identified several defects	IWR N2340

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
			The inspection reports, maps and pictures are stored in TRIM (Record: MF2330) for each site.	across multiple sites. An IWR has been initiated for the remediation work	
Transformer Compound Walls	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	The first generation of Transgrid compound wall panels were inadequately attached. Vertical panel members have started to fail and break away from the steel columns. The broken sections are dense and heavy and represent a safety risk to Transgrid staff and contractors.	Condition assessments of compound walls have been completed. A remediation program has been developed to rectify affected transformer and reactor compounds.	RP3 – (2023-28) Planned	Need: N2601
Ingleburn Flood	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Ingleburn substation experienced minor flooding June 2016. Some issues with adequacy of the building compound deluge pumps and the existing drainage system have been identified and should be rectified.	Identify and rectify the site issues in order to improve the reliability of the site during flood events. Scope is dependent on determining likely reoccurrence of flooding.	In progress The flood mitigation scoped developed under IWR0106 has been bundled with the Ingleburn secondary systems	IWR0106 Need:1225

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
				renewal (Need:1225).	
Darlington Point Flooding	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Flooding in 2012 almost resulted in operation impact and a review of the site has identified areas which may need to be addressed in order to eliminate the risk of future flooding.	Identify and rectify the site issues in order to improve the reliability of the site during flood events.	In Progress	
Substations with grass switchyards	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Converting the remaining grass sites to gravel under a discrete project has advantages for fire risk mitigation and maintenance.	Evaluate the cost and benefits of converting to grass sites.	In progress	n2273

5.2.3. Maintenance Program - Infrastructure

Maintenance for site infrastructure is largely defect based and depends on review and rectification of defects raised during substation inspection activities. These include:

- General substation inspections
- Steelwork inspections
- Oil containment inspections
- Earthing system inspection and testing

5.3. Transformer Asset Review

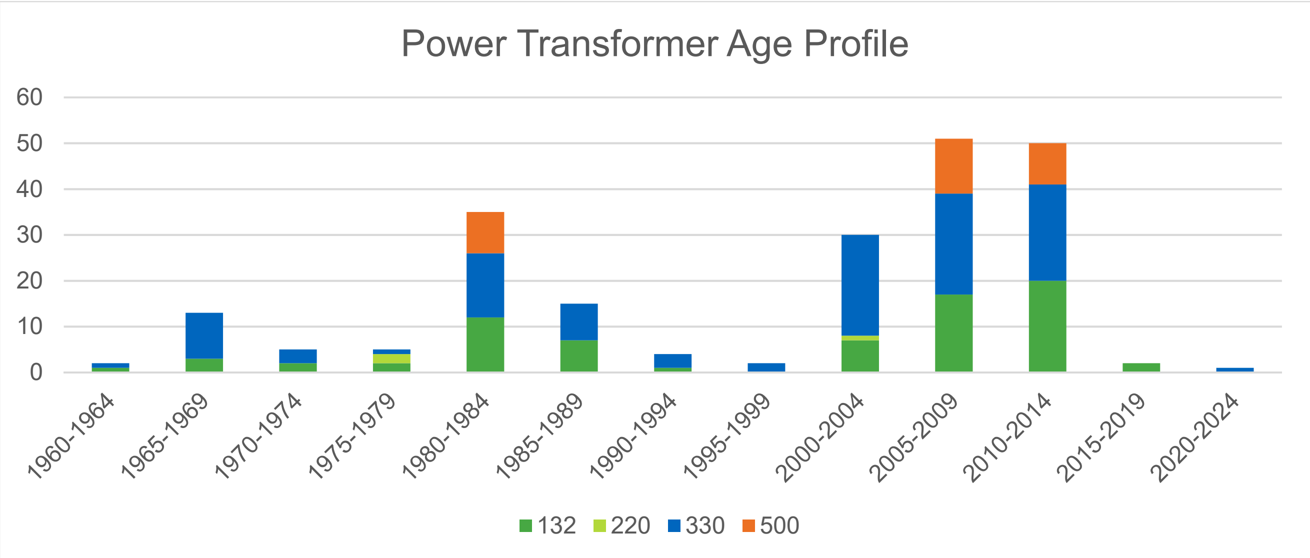
5.3.1. Population Review - Transformers

Transgrid's power transformer population is comprised of 218 individual units. Of these:

- 72% are rated above 100MVA with a primary voltage of 132kV or higher.
- 18% are single-phase units.
- 82% of three phase equivalent transformer installations have on-load tapchangers.

The power transformer age profile is shown in Figure 22. It shows that 6% of our fleet were commissioned prior to 1975, and have thus exceeded their nominal lifespan of 45 years. The oldest unit was manufactured in 1960. The average age of Transgrid's transformer fleet is approximately 24.1 years.

Figure 22: Power Transformer – Age Profile



5.3.2. Emerging Issues, and Renewal and Maintenance Initiatives

As power transformers are generally the most expensive single item of substation plant, significant maintenance and monitoring attention is directed to them and hence these plant items have the most comprehensive set of condition data.

Transgrid utilises a transformer health index methodology to identify those transformers with the highest risk of failure. Using this information as a guide, detailed condition assessments are prepared for a broad range of higher risk transformers, which are then analysed to determine the need for corrective action. The analysis takes into consideration:

- Population age profiling against nominal asset lifespan.
- Service history information such as tapchanger history and operations
- Physical condition (e.g.: leaks, paint condition, corrosion etc.).
- Diagnostic testing results – such as electrical, mechanical and chemical – main windings and bushings
- Type issues.
- Failure and defect rates.
- Failure investigations.
- Maintenance program outcomes.
- Online condition monitoring.
- Criticality

Issues may develop with the condition of power transformers and oil filled reactors that may limit their life or affect their reliability. Of the known, current and emerging issues – the following general condition issues have been identified:

- Accelerated deterioration of insulating paper quality - excessive paper moisture content, oil acidity and oxygen content are factors that will promote the chemical reactions and lead to rapid deterioration of paper strength.
- Combustible gases in oil – high levels of dissolved volatile gases in oil samples are an indication of abnormalities which may lead to the development of a significant internal fault
- Tap-changer condition or type faults – Tap-changer failure (particularly diverter switches – which result in total failure of the transformer) have been responsible for around 35% of Transgrid's major transformer failures in the available records. Particular issues are:
    - The development of silver sulphide on the silvered contacts of selector switches on some transformers is an emerging issue. This problem may be related to corrosive compounds in oil created in the process of fuller's earth treatment of oil in past refurbishment works. The problem was found during internal inspection made in the course of transformer refurbishment.
    - If the development of silver sulphide is allowed to progress without interruption, pieces of conductive silver sulphide may lead to a rapidly developing internal fault and transformer failure.
    - Cleaning of contacts has been completed where the problem was found in refurbishment. Options to identify and treat affected transformers are being investigated.
    - A small number of transformers have been found with anomalous winding resistance results through the tapping range. These results have been improved by repeatedly running the tap-changer through the tap range. The affected transformers typically only operate in a narrow tapping range. Internal inspection will be required for at least one of these transformers to determine the underlying cause.

- Leaking tap-changer barrels – Certain tap-changer diverter switches have been manufactured with insufficient sealing between the main transformer tank diverter switch tank oil volumes. The resulting cross-contamination results in abnormal levels of dissolved gases in the main tank, obscuring any effective DGA – which remains our key diagnostic tool.
- Carbon contamination has also been noted in transformers with leaking tap-changer barrels. This has the potential to shorten the life of transformers due to the unpredictable effect of quantities of carbon inside the main transformer tank.
- Diverter switch failure due to failed components or differential wear of contacts.

With the increase in connection of wind and solar farms to Transgrid's network, it is expected that the number of operations of tap changers at connection point will increase.

- Bushing failures - Bushing failures have caused approximately 32% of major transformer failures in Transgrid's records, an issue which is compounded by a lower nominal lifespan for bushing insulation systems than that of the transformer in which they are installed.
  - There are some significant issues that have been identified with respect to transformer bushings:
  - Oil Impregnated Bushings (OIP) are sealed with gaskets which are susceptible to failure through brittleness brought on by age and weather exposure. Entry of even a very small amount of water into the small oil volume of a bushing will eventually lead to explosive failure - and could be expected to result in the catastrophic failure and loss of the associated transformer through fire.
  - A model of 132 kV OIP bushing fitted to 23 supplied 330 kV 375 MVA transformers have been identified as suspect, likely due to a manufacturing or design defect. Two bushings with well developed faults that would have led to failure have been detected by on-line monitoring systems, averting explosive failures that would have resulted in the loss of the associated transformer. The bushing failures were characterised by extensive internal carbonisation damage, found when the bushings were stripped. Additional monitoring of these bushing types using oil sampling/Dissolved Gas Analysis has found possible signs of developing failure in a further seven bushings. All of these bushings are being replaced.
  - Micafil Synthetic Resin Bonded Paper (SRBP) bushings have been identified as a type with a potentially higher risk of failure due to a known mechanism. Delamination of the bonded paper layers comprising the insulation system (thermal cycling issue) can lead to partial discharge activity and breakdown of the primary insulation. Transgrid have removed all 330kV bushings of this type; and only 132 kV (6) and 66 kV (3) bushings remain in service at Murray and Panorama Substations.
- Corrosion – Failure of paint systems will lead to corrosion of the tank, pipe work, radiators and fittings. This can result in mechanical failure of the main tank wall, leading to oil leaks and moisture ingress. Radiators are particularly vulnerable due to the thin cross-section steel walls used in coolers (for effective heat transfer).
- Paint system deterioration - This can lead to corrosion and can be more expensive to address if allowed to deteriorate too much.
- Oil leaks – Gaskets on transformers may become brittle with age and exposure and fail. Chronic oil leaks result in pools of oil around the transformer, which present a fire risk. Leaks are a source of water entry. Chronic leaks may result in contamination of the ground around the transformer with commensurate potential environmental issues.

- Oil contamination – Oil may become contaminated with particles or other materials and this will affect dielectric performance.
- PCB contamination – Some Transgrid transformers remain with low levels of PCB. However, in the event of a failure involving fire and oil release there may be repercussions and reputational impacts to the organisation due to the high profile of the chemical, regarding the potential for environmental damage.
- Worn ancillary components – in particular fans and pumps. Full transformer rating is only available with all fans and pumps in good condition.

A small number of site specific issues exist that result from isolated specific issues. These are analysed and site specific plans are prepared.

The following planning issue has become an issue with the implementation of the transformer refurbishment plan:

- Rural substations with two transformers may have insufficient backup capacity to accommodate a long transformer outage with an extended emergency return to service time. This occurs where a midlife refurbishment or major overhaul is required. The problem is most significant if a dry out is required as this greatly extends the recall time.

If the risk is considered unacceptable, a Need developed and evaluated in accordance with the Prescribed Network Capital Investment Process. The course of action is generally to either to: observe the asset; undertake refurbishment; replace; or dispose of the asset.

The current and emerging issues, and renewal and maintenance initiatives are summarised in the table below.

5.3.3. Auxiliary Transformers

Transgrid's Auxiliary Transformers are maintained in line with other major equipment in the various substations. In general, auxiliary transformers are lightly loaded, and are expected to meet or exceed the life of the other substation components, such as power transformers.

In 2019, an issue has emerged relating to moisture ingress leading to corrosion within TMC dry type 11/0.415kV auxiliary transformers. There have been six similar issues since the transformers were installed, and as a result, this is being treated as a likely type fault. Further inspections, which may drive rectification works, are planned for the entire fleet of TMC dry type transformers.

Transgrid's approach to Auxiliary Transformers is to assess them for refurbishment or replacement when either the primary transformer is being replaced, or when the secondary systems are being replaced, and specifically the 415V system within the secondary systems. This bundling allows for efficiency of outages and mobilisation.

5.3.4. Emerging Issues and Renewal and Maintenance Initiatives

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 9: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Transformer Replacement Program.	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Based on the Transformer Health Index Methodology: • Ageing transformer population that are above or approaching their nominal useful life • Ageing OIP and SRBP bushings that are above their nominal useful life. • Poor oil quality • Out of tolerance dissolved gases indicating thermal and electrical stresses. • Corrosive Sulphur • High moisture content in the insulating paper and oil. • Oil leaks and corrosion • Lack of voltage control to compensate for network voltage fluctuations	Renewal initiative: Replace 10 transformers.	RP3 – (2023-28) Planned	Need No: N2404 N2421 N2422 N2423 N2424
Transformer Refurbishment Program.	• Manage network safety risk • Maintain network reliability	Based on a compilation of condition monitoring data Serious oil leaks. Unsatisfactory oil quality parameters.	Renewal initiative: Refurbish 11 transformers.	RP2 – Underway PC 30/6/23	Need No: 1354

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
	• Manage assets efficiently to deliver security holder and consumer value	Moisture in oil measurements (used to estimate moisture in paper) for all units listed are considered to be abnormal. Poor oil quality which will significantly adversely impact the paper insulation quality			
Marulan No.4 Transformer Replacement	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Same as replacement program above	Renewal initiative: Replacement with a new unit	RP2 – Underway PC 30/6/23	Need No: 1219
Forbes Transformers Replacement		Same as replacement program above	Renewal initiative: Replacement with two new units	RP2 – Underway PC 30/6/23	Need No: DCN276
Sydney East Transformers Replacement		Same as replacement program above	Renewal initiative: Replace No.3 with an in service spare unit, retire No.2 and keep No.1 in service	RP2 – Underway PC 30/6/23	Need No: DCN548
Bushing Replacement Program	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Based on natural age Potential moisture ingress due to seal failure Lack of accurate bushing dimensional details would cause prolonged emergency replacement	Renewal initiative: Replace bushings on 11 transformers and reactors.	RP2 – Underway PC 30/6/23	Need No: 1525
Transformer paper moisture estimation	• Minimise environmental harm and property damage	Water content tends to increase as paper insulation ages	Monitor paper moisture in real time to defect emerging	In progress -	IWR-N2378

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
	• Maintain network reliability • Asset Management Program of Works	Moisture from the atmosphere due to degraded seals and gaskets	condition issues and evaluate effectiveness of the technology.	Trials have been initiated at Sydney East to compare paper samples and the online estimation method.	
Transformer protective device trips	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	There have been a number of spurious trips due to moisture ingress of transformer protective devices (e.g. buchholz relays)	Review causes and determine appropriate actions.	Not commenced.	

5.3.5. Maintenance Program– Transformers and Reactors

5.3.5.1. Component Failure Risk Assessment – Transformers and Reactors

A component failure risk assessment has been conducted for the Transformer and Reactor asset class and is shown in the table below. The analysis is compared with the Substation Maintenance Plan for the asset class to demonstrate alignment between potential component failures and preventative maintenance activities prescribed to diagnose them.

Table 10: Component Failure Risk Assessment - Transformer & Reactor

			Risk			Preventative				Linkage Business Plan Objectives
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Oil sampling**	**Planned maintenance**	**OLCM**	
Bushings - Oil impregnated	Insulation breakdown type fault/damage/water	Tx loss	3	3	9			Bushing DDF/ Capacitance	Bushing monitor – selected bushings only	Safety Reliability Environment
	Water ingress	Tx loss	3	3	9			IR /Dirana		
	Hot joints	Tx loss	2	3	6	Thermovision				
	Oil loss/external damage	Tx loss	1	3	3	Inspection				
Bushings - Resin Impregnated	Insulation breakdown type fault/damage/water	Bushing loss	3	2	6			Bushing DDF/ Capacitance		
	Water contamination	Bushing loss	1	2	2			IR /Dirana		
	Hot joints	Bushing loss	2	2	4	Thermovision				
	External damage	Bushing loss	1	2	2	Inspection				
Winding/ Main insulation	Fault - various causes - lightning damage, type fault etc.	Tx loss	1	3	3		DGA - signature gasses			Safety Reliability Environment
	Core fault causing overheating	Tx damage	0.5	2	1		DGA	Core IR		Reliability
	Degradation - due to oil condition and ageing reactions	Tx loss	1	3	3		OQ and DGA			Safety Reliability Environment
	Low oil	Trip	3	1	3	Inspection				Reliability

			Risk			Preventative				Linkage Business Plan Objectives
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Oil sampling**	**Planned maintenance**	**OLCM**	
Tap-changer	Selector hot joints	Tx loss	1	3	3	Check cyclometer	DGA	Winding Resistance	Oil monitor	Safety Reliability Environment
	Selector mechanical wear and unseen problems	Tx loss	2	3	6	Check cyclometer		Internal inspection based on cyclo		
	Oil Diverter switch wear	Tx loss	3	3	9	Check cyclometer		Internal inspection/measurement		
	Oil Diverter switch oil breakdown or tracking	Tx loss	2	3	6	Check cyclometer		Internal inspection/oil change		
	Oil Diverters switch mechanical failure	Tx loss	3	3	9	Check cyclometer		Internal inspection and maintenance activities		
	Vacuum Diverter switch wear	Tx loss	1	3	3	Check cyclometer				
	Vacuum Diverter switch oil breakdown or tracking	Tx loss	2	3	6	Check cyclometer	OQ tests			
	Vacuum Diverters switch mechanical failure	Tx loss	1	3	3	Check cyclometer				
Cooling	Pump failure (wear, electrical failure etc.)	Rating restriction possible overheating	1	1	1	Check operation			Traditional thermal protection - universal	Reliability

			Risk			Preventative				Linkage Business Plan Objectives
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Oil sampling**	**Planned maintenance**	**OLCM**	
	Fan Failure (wear, corrosion, electrical failure etc.)	Rating restriction possible overheating	3	1	3	Check operation				
Oil condition	Water ingress - breather	Degradation of main insulation	2	1	2	Inspection/ Breather maintenance	OQ tests		Oil moisture monitor on selected units	Reliability
	Water ingress - leaks		2	1	2	Inspection/ defect repair	OQ tests			
	Water ingress - corrosion		2	1	2	Inspection/ defect repair	OQ tests			
	Loss of inhibitor - where appropriate		2	1	2		OQ tests			
	Contamination		2	1	2		OQ tests			

5.3.5.2. Maintenance Program Amendments – Transformers and Reactors

Transformer and reactor maintenance was reviewed previously and changes in frequency were made based on a consideration of the above risks. The objective of the change is for efficiency gains in the delivery of equipment maintenance.

The changes in maintenance affecting transformers included:

- A reduction in inspections.
- Substation inspections are now scheduled at 6 monthly intervals for most substations and 12 months for substations less than 10 years old. The impacts on transformer reliability arising from this are expected to be minor. From the table above, the items impacted by inspection maintenance are lower ranked risks.
- An extension of the time between major maintenances

  The interval for maintenance of transformers was formerly 4 years and this has since been extended to 6 years with the following restrictions:

  - The interval remains at 4 years for oil impregnated bushings unless they are equipped with functioning on line bushing monitors. This recognises the potentially high risk associated with bushing failure of oil impregnated bushings. Failure of resin impregnated bushings are not expected to result in loss of the transformer.
  - Maintenance of tap changers may still be required on an operations basis.

5.3.6. On Line Condition Monitoring – Transformers and Reactors

The principal options considered for on line condition monitoring (OLCM) of transformers and oil filled reactors include:

- Bushing monitors – which compare the bushing insulation leakage current between a three phase set to identify changes and raise alarms for a fast or large change.
- Dissolved Gas monitoring. There are a range of devices available ranging from devices such as ‘Hydrans’ which are sensitive mainly to hydrogen gas, through to what is effectively an online full gas chromatograph. These can detect changes in gas levels and provide alarming.
- Moisture monitors can be used to estimate the water in paper content of transformers/reactors. This can be difficult to estimate from water in oil measurements due to the need to reach a high enough equilibrium temperature over a time period.
- Partial discharge monitors. These devices are aimed at detecting partial discharge occurring within the transformer but have not been found to be effective in past trials.
- Fibre-optic temperature measurement. A measurement of transformer ‘hot-spot’ temperature can be made directly using fibre optic probes. This is dependent on the accuracy of transformer design models for placement of the probes. These devices have been found to be unreliable for long term service in previous installations although they may still have some value in confirming transformer thermal designs in factory acceptance testing.
- Tapchanger monitors may monitor mechanical action and motor drive currents etc. These have been found to be too expensive in past experience with minimal risk reduction compared to proper attention to maintenance practice.

Transgrid previously had a practice to install gas monitors (hydran type) with moisture monitoring; and bushing monitors. Future new transformers will not be specified with these devices due to various issues experienced in the past (details are in section 5.12.2). For oil bushing failure risks, RIP bushings to be installed to minimise catastrophic bushing failure risks.

Where OLCM equipment is installed on oil filled reactors and transformers, there is a reduced maintenance requirement recognising the reduction in risk. The information from OLCM device can also provide accuracy in health index or ageing trend and would assist in making accurate decision about renewal of Power Transformer. Where OIP bushings are not due to be replaced in this or the next regulatory period, there is an initiative to install OLCM bushing monitoring to manage the risk of failure.

5.4. Reactors Asset Review

5.4.1. Population Review - Reactors

Transgrid has a population of 106 reactor units equivalent to 52 three phase reactors that is comprised of 39 oil-filled types, 3 (1 three phase unit) SF6 insulated types and 60 (20 three phase sets) air-cored types. Of the air cored types, 18 (6 x three phase) are line series reactors.

When in service, shunt reactors are operated at around 100% of design loading. This is in contrast to transformers that are in service continuously but are normally designed to supply a peak load using n-1 reliability criteria. Shunt reactors may typically be switched daily, leading to additional internal stresses – and may operate for some hours each day. As Reactors operate at full load temperatures constantly (whilst energised) their insulation systems deteriorate at a faster rate than transformers and this is reflected in a lower expected nominal life compared to transformers.

Transgrid Oil-filled Reactor population is comprised of

- 2 x 330kV series reactors.
- 39 (35 three-phase equivalent) shunt reactors; consisting of:
  - 6 x 330kV single-phase units.
  - 24 x 330kV three-phase units.
  - 5 x 220kV three-phase units.
  - 4 x 132kV three-phase units

SF6 Reactor population is comprised of:

- 3 x single-phase SF6 gas insulated reactors at Haymarket

Air-cored Reactor population is comprised of:

- 18 x single-phase air-cored series reactors at 132kV
- 9 x single-phase air-cored shunt reactors at 132kV
- 33 x single-phase air-cored shunt reactors at 33kV

The age profile for oil-filled reactors is shown in Figure 23 below. However, given the small number of SF6 insulated reactors and their relatively uniform operating life, graphical data regarding their age profile has not been included.

Whilst the average age of the oil filled reactor population is approximately 17 years, 9% were commissioned before 1990 and have thus exceeded their nominal lifespan of 30 years, with the oldest units manufactured in 1983. Of the other reactors currently in service, the SF6 reactors are installed in the Haymarket Indoor GIS Substation which was commissioned in 2004 and all are in an early stage of their life.

Figure 23: Oil Filled Reactors – age profile

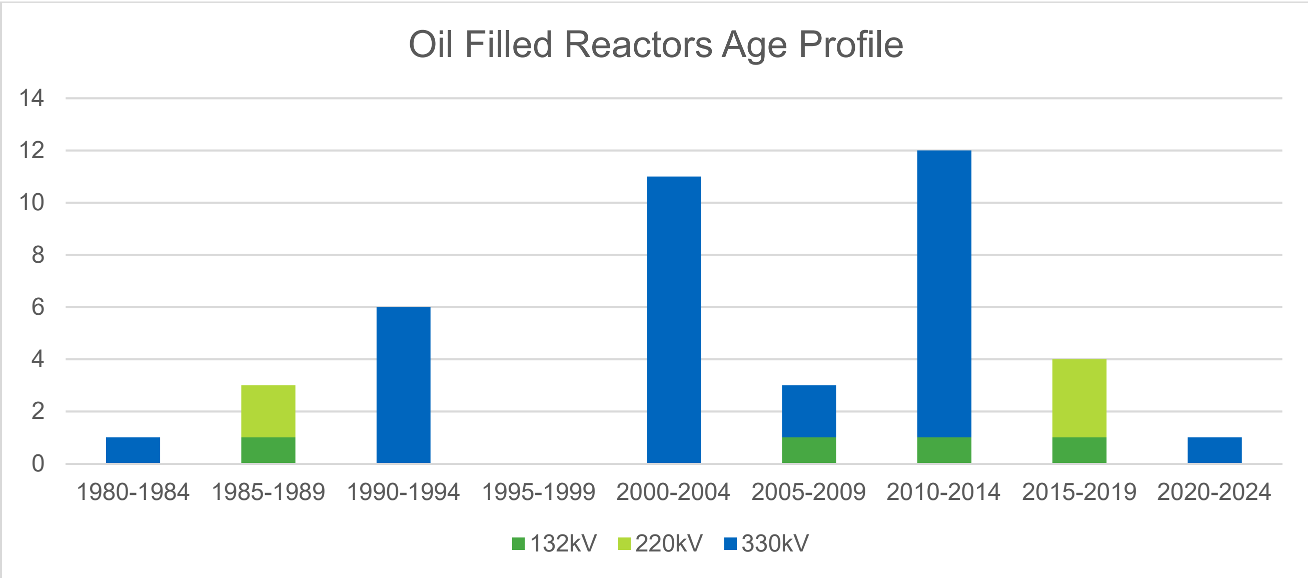
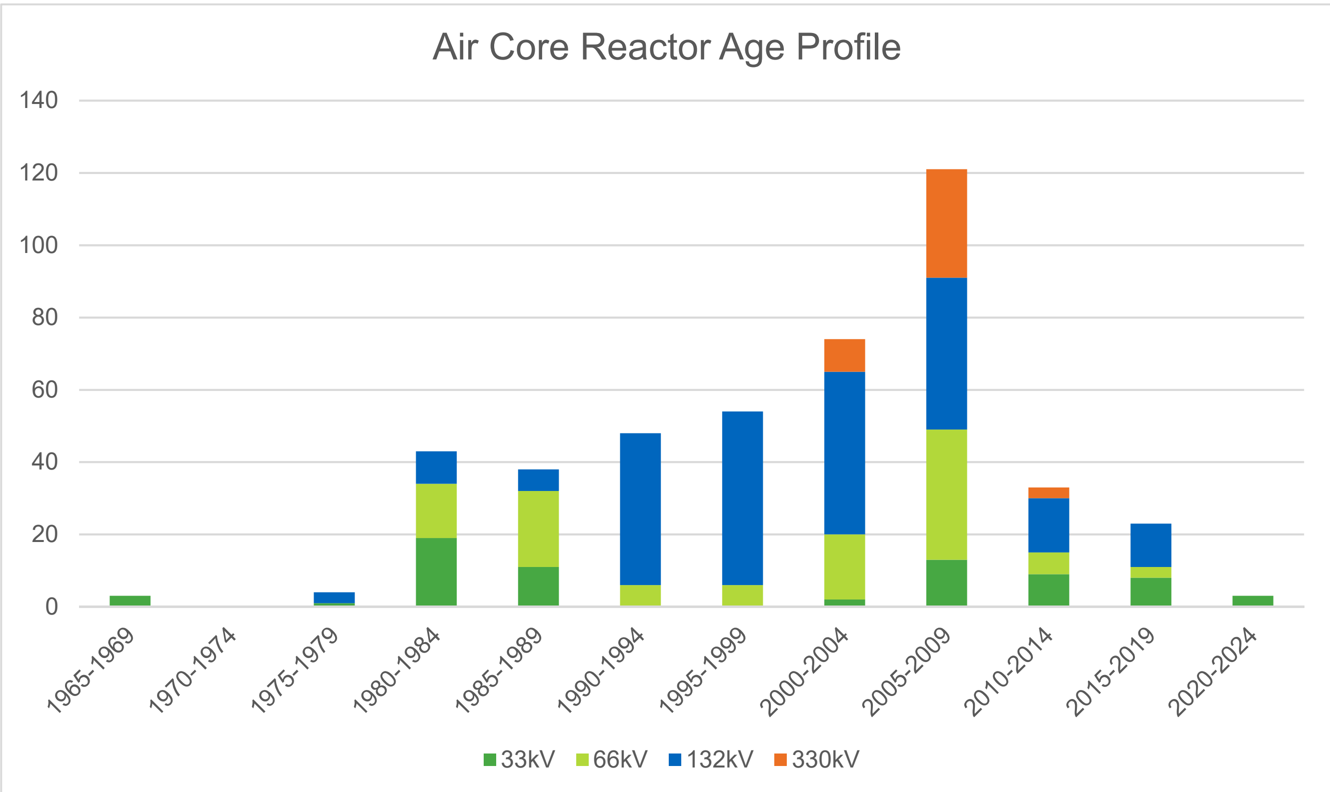


Figure 24: Air Cored Reactor – age profile



5.4.2. Emerging Issues, and Renewal and Maintenance Initiatives

5.4.2.1. Oil Filled Reactors

Aside from the considerations related to the loading cycle of reactors, the issues that affect oil filled reactors are very similar to those impacting on similarly insulated power transformers, as detailed in Section 5.3.2.

A similar range of diagnostic data is available for oil-filled reactors as a result of their similar construction and capital value compared to power transformers. A health review is used to identify reactors with the highest risk of failure and using this information, detailed condition assessments are prepared for a range of higher risk reactors, which are then analysed to determine the need for corrective action.

Issues may develop with the condition of oil-filled reactors that may limit their life or affect their reliability:

- Accelerated deterioration of insulating paper quality - excessive paper moisture content, oil acidity and oxygen content are factors that will promote the chemical reactions and lead to rapid deterioration of paper strength. In the case of oil filled shunt reactors this is affected by their loading cycle.
- Combustible gasses in oil – high levels of dissolved volatile gases in oil samples are an indication of abnormalities which may lead to the development of a significant internal fault
- Bushing failures - Bushing failure has caused approximately 32% of major transformer failures in Transgrid’s records and a similar risk exists for bushings fitted on reactors.
    - Oil Impregnated Bushings (OIP) are sealed with gaskets which are susceptible to failure through brittleness brought on by age and weather exposure. Entry of even a very small amount of water into the small oil volume of a bushing will eventually lead to explosive failure - and could be expected to result in the catastrophic failure and loss of the associated reactor through fire.
- Corrosion – Failure of paint systems will lead to corrosion of the tank, pipe work, radiators and fittings. This can result in mechanical failure of the main tank wall, leading to oil leaks and moisture ingress. Radiators are particularly vulnerable due to the thin cross-section steel walls used in coolers (for effective heat transfer).
- Oil leaks – Gaskets on transformers may become brittle with age, exposure, and fail. Chronic oil leaks result in pools of oil around the transformer, which present a fire risk. Leaks are a source of water entry. Chronic leaks may result in contamination of the ground around the transformer with commensurate potential environmental issues.
- Oil contamination – Oil may become contaminated with particles or other materials and this will affect dielectric performance.
- Worn ancillary components – in particular fans and pumps. Full rating is only available with all fans and pumps in good condition.

If the risk is considered unacceptable, a Need developed and evaluated in accordance with the Prescribed Network Capital Investment Process. The course of action is generally to either to: observe the asset; undertake refurbishment; replace; or dispose of the asset..

5.4.2.2. Air Cored Reactors

The reactors have failed following deterioration of their paint coating. This is thought to have allowed embrittlement of the mylar interturn insulation once water sealing of the insulating material was lost with failure of the painting system. Thermovision was completed on the remaining reactors at the affected sites, Kemps Creek and Eraring, and this confirmed the presence of hotspots throughout the remaining reactor coils.

In the longer term, the issue has potential to affect the newer air cored reactors installed in the 500 kV sites (Bannaby, Mt Piper and Bayswater).

There have also been unexplained failures of reactor coils at Darlington Point at 24 years of age and these may be due to manufacturing issues.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 11: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Air Cored Reactors	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Insulation failure	Renewal initiative: Replacement of failed and ageing reactors in 500kV substations	PC: June 2021	Need No: 1279 Need No: 1367
Wellington No.1 Reactor	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Insulation degradation (oil and paper) Oil contamination Oil leaks	Renewal initiative: Reactor Replacement	RP2 PC: 30 June 2023	Need No: 1282 P0005463
Armidale No.2 Reactor		Insulation degradation (oil and paper) Oil contamination	Renewal initiative: Reactor Replacement	Complete	Need No: 1607
Transformer and Reactor Bushing Replacement Program.		Moisture ingress Ageing prematurely Type issues Extreme high consequence of failure	Health Index (HI) data combined with Probability of Failure and criticality data identified assets with positive cost benefit evaluation for renewal when weighed against evaluated ongoing risk cost. Renewal initiative: Replace identified bushings	RP2	Need No: 1525

5.4.3. Maintenance Program - Reactors

See section 5.3.4 Emerging Issues and Renewal and Maintenance Initiatives.

5.4.4. On Line Condition Monitoring – Reactors

See section 5.3.6 On Line Condition Monitoring – Transformers and Reactors.

5.5. Circuit Breakers Asset Review

5.5.1. Population Review – Circuit Breakers

Transgrid's circuit breaker (CB) population comprises 1,486 units in the voltage range from 11kV to 500kV. The types of CBs used include Small Oil Volume (SOV), Vacuum and SF6. SOV CBs are old technologies are mainly in use up to 132kV.

Recently supplied CBs are either SF6 type or vacuum type, where SF6 is used to provide primary insulation. Vacuum interrupter CBs are presently used in CBs up to 33 kV. Most of Transgrid's CBs are of the SF6 type and there is an evolution moving from older puffer types with hydraulic mechanisms that suffered from gas leaks through to lighter spring operated 'self-blast' puffer types.

The CB age profile and population breakdown are shown in the Figure 25 and Figure 26. They show that 1.75% of the units were commissioned before 1981, and have thus exceeded their nominal lifespan of 40 years. The oldest units were manufactured in 1967. The CBs have an average age of approximately 17.3 years. Figure 27 shows the distribution of circuit breaker voltage types against age.

Figure 25: Circuit breaker – age profile

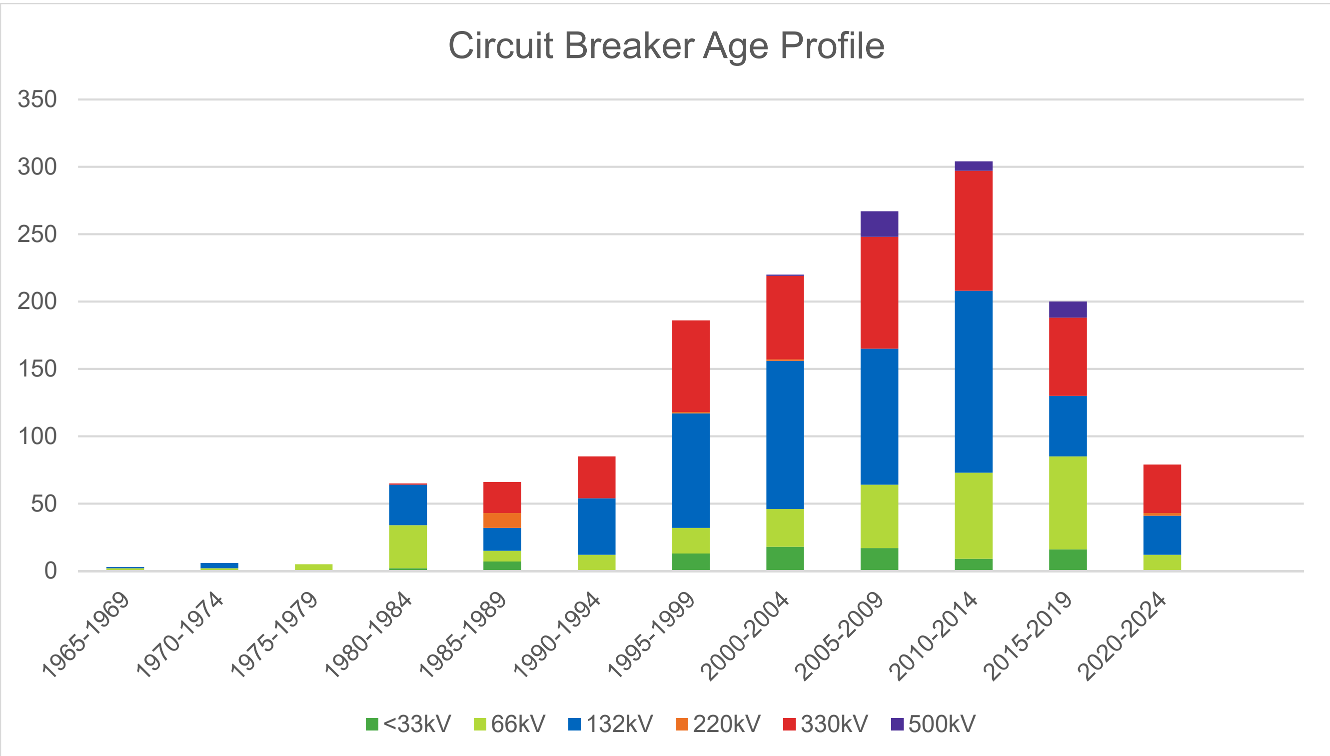


Figure 26: Circuit breaker – population breakdown

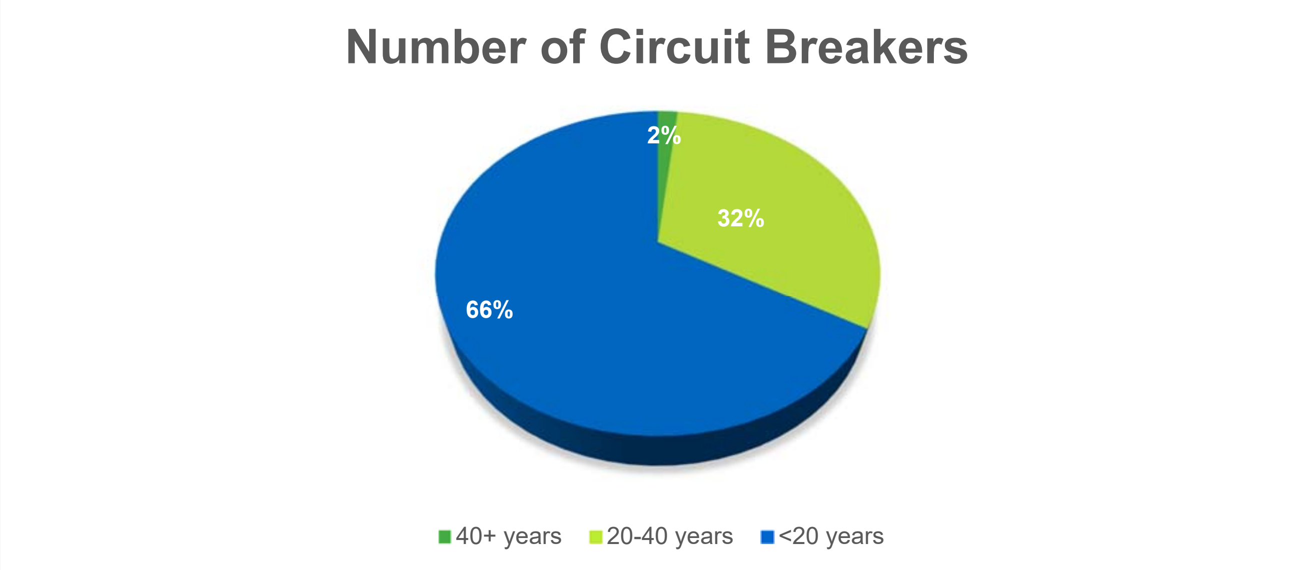
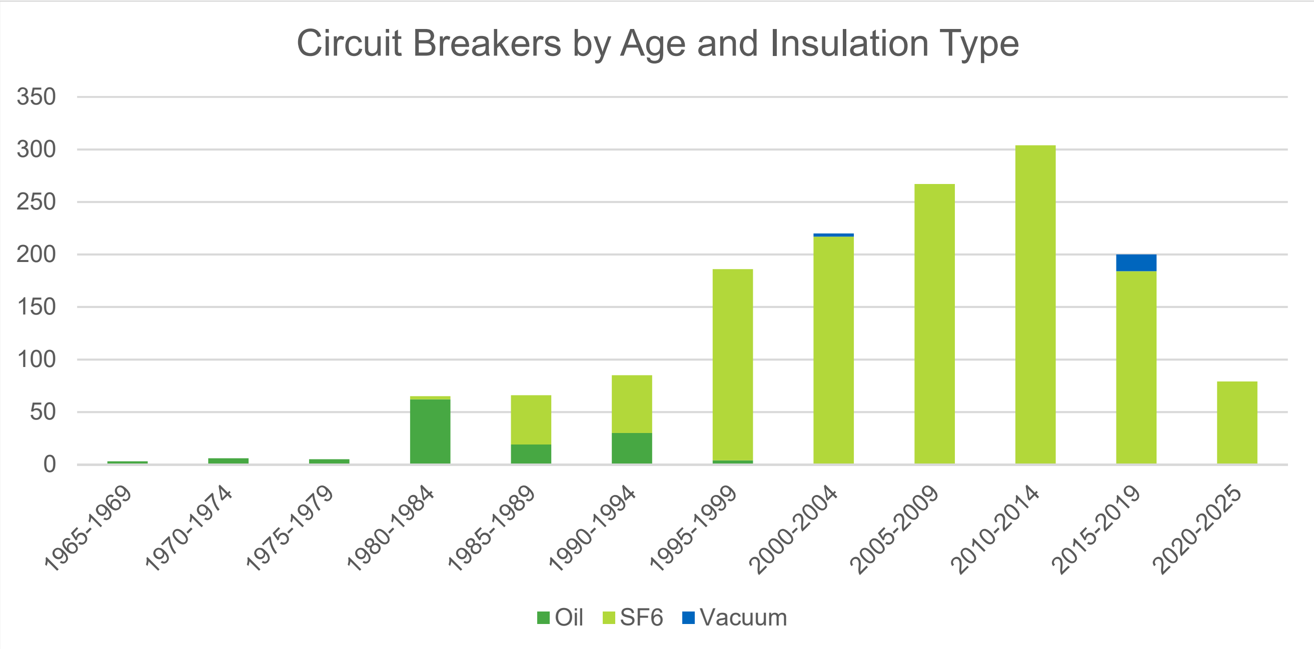


Figure 27: Circuit breaker – Population profile by type



There have been 208 circuit breakers identified for retirement in the 2018/19 to 2022/23 period as a result of replacement programs arising from Health Index and risk review. This represents 14.1% of the circuit breaker population. 137 circuit breakers have been identified for replacement during the period 2023/24 to 2027/28, which represents a further 9.2% of the population.

5.5.2. Emerging Issues, and Renewal and Maintenance Initiatives

The current circuit breaker population has been supplied over a 40-50 year time frame and there has been development of technology over that time. The following groupings are noted:

- Small oil volume circuit breakers, which are now an unsupported technology with limited or no technical, or spares support from the supplier. These are also the oldest of the circuit breaker fleet.
- Early generation SF6 circuit breakers using puffer technology for arc extinguishing but requiring hydraulic or powerful clock spring mechanisms to provide the necessary energy to operate.
- More recent SF6 types utilising arc energy to assist with operation of the circuit breaker. These devices are lighter in construction, spring operated and reliability has been generally good.
- Point on wave capability has been included in SF6 circuit breakers installed on capacitors. This has been achieved using a single output switching relay and ganged mechanisms or by individually switched poles with three switching impulses.
- Dead tank SF6 circuit breakers are available up to 330kV and experience with these has been very good to date and are a preferred substation design choice as they incorporate maintenance free and reliable current transformers into the circuit breaker.
- Vacuum circuit breakers are used at lower voltages (33 kV and below) using SF6 or air for primary insulation. Vacuum circuit breakers have the lightest mechanism construction.

Transgrid utilises a Health Index Methodology to consider the effective age of an asset and the statistical failure risk of an asset with consideration of asset condition data. Factors used to evaluate Circuit Breakers in the Health Index assessment include:

- Natural Age
- Cyclo operations
- Defect counts
- Defect cost
- Reactive plant switching duty
- Diagnostic test data
- Type Issues

The health index factors influence effective age evaluation for asset renewal consideration. As a result, asset renewal replacement program is largely comprised of assets with high relative scores of one or more of the factors. Some typical groups of these asset types are discussed below:

- High Operation Count/Frequency Circuit Breakers - A small population of circuit breakers are required to switch frequently, consuming mechanism and electrical life at an increased rate compared to typical transmission circuit breakers.
  - Affected circuit breakers are typically associated with generator connections points and reactive plant that are switched to manage load variations that can be a daily cycle. The increased wear rate is considered in the health index and may result in a reduced service life as low as 10 years.
- Reactive plant circuit breakers experience accelerated wear compared to typical transmission circuit breakers. This results from high frequency switching and the type of load being switched. Lifecycle cost of overhauling high wear components may not be economical and an individual replacement may be required.
- Type issues are typically identifying a performance issue affecting a population with a common design or model. Type issues considered in the HI assessment when evaluating Circuit Breakers include:

- Small oil volume (SOV) Circuit Breakers – SOV CBs are an obsolete technology that has limited manufacturer support. The availability of new spares is limited and may be expensive. Personnel who were involved in design of these circuit breakers have typically retired or moved to other roles.
- Mechanism problems are appearing with these circuit breakers that lead to slow operation; failure to trip; out of tolerance condition monitoring results; and 'shoot through'. Oil leaks are found on these units and they require intrusive maintenance – affected by the number of fault operations.
- Hydraulic and Heavy Spring Circuit Breakers - These circuit breakers are early generation SF6 designs employing hydraulic operating mechanisms due to the high forces that must be provided by the operating mechanism during fault operation. The interrupters themselves are heavier than more recent types and damping may hence be more critical.
- Magrini Galileo SF6 Circuit Breakers - The 33kV SF6 design CBs are an early design generation of SF6 CBs from the early to mid 90s. The design is currently owned by Schneider Electric who have identified that technical and spare parts support has ceased with minimal spares held by the manufacturer and Transgrid stores.
- The population have also been subject to high defect rates with one unit identified through routine maintenance in critical and life ending condition. It is expected that future defects will be high cost to repair with an increased risk of infeasible repair resulting in increased risk of life ending failure.

The design preference is for Dead Tank circuit breaker designs for asset renewal and new installations:

- Dead tank CBs have in-built instrument transformers and do not require separate current transformer assets. There is benefit in the elimination of separate post current transformers with their associated failure risk and maintenance costs. These have been installed over the last 20 years and have proven to be successful.
- A policy has been developed to replace circuit breakers with dead tank type when circuit breaker replacement is required and the risk associated with the adjacent current transformers is sufficient to justify the increased capital costs. This is supported by the maintenance cost saving, reduction in future outages and reduced operational risk. Details of benefits are in D2015/07219: Issue Paper – Dead Tank CBs.
- Utilisation of Dead Tank CBs is also preferred for new outdoor installation where ever feasible and providing the benefit of eliminating separate current transformer assets.

Further emerging issues with the circuit breaker asset class are as follows:

- High current switching reactor circuit breakers – The Transgrid network contains 11 33kV air core reactor installations and associated circuit breakers that are connected to transformer tertiary windings to the HV network. Switching operations of these circuit breakers have been identified as presenting a very high wear rate of the CB contacts due to the high reactive switching current.
  - Low operating voltage and relatively high MVAr capacity results in high reactive switching current.
  - Electrical characteristics of air core reactors result in very high transient recovery voltages with high risk of restrikes occurring and arcing continuing for multiple cycles.
  - A number of installations have been found in premature life ending condition requiring urgent replacement, this has included some catastrophic CB pole failures.
  - Efforts to determine maintenance practices, bay design and equipment ratings that deliver optimal life cycle cost to mitigate the high electrical wear rate are ongoing.

- SF6 leaks in the circuit breaker population are an ongoing concern - SF6 insulation in HV circuit breakers is the current technology being procured for circuit breaker installations which are increasing the total number of SF6 insulated CBs in service and the total installed holding of SF6. Leaks are monitored by the Asset Monitoring Centre through review of resulting alarms and online monitoring data and reported to Asset Management. Unless a type issue can be identified, SF6 leaks are managed in accordance with the Corrective Maintenance Process and the Condition Monitoring Manual.
  - The Paris Agreement is an agreement within the United Nations Framework Convention on Climate Change (UNFCCC) dealing with greenhouse gas emissions. The agreement has the potential to result in government and regulatory pressure to set a more conservative benchmark on allowable losses or remove SF6 from service.
  - Circuit breaker designs have become commercially available which include vacuum interrupters up to 132kV combined with non-SF6 insulation, however they come at a cost premium to conventional arc in SF6 designs. A small number of this CB design are proposed to be procured and installed on the network in order to gain experience with the new technologies.
- SF6 gas testing has begun to identify circuit breakers with high moisture levels. Moisture levels that do not comply with the condition monitoring manual limits are addressed through defects. Results are being monitored and evaluated where a common make/model of circuit breaker is frequently presenting with high moisture:
  - A small number of ABB EDF 33kV & 66kV circuit breaker poles have been identified with high moisture during routine maintenance. Developments for this population are being monitored as results become available from routine maintenance activities.
- Alstom OX36 circuit breakers are a dead tank design utilising vacuum interrupters in a low pressure SF6 chamber – despite being installed from ~2000, the condition of this population has deteriorated rapidly. The manufacturer provides very limited parts and service support for this model while the population have various common issues, which can be irreparable or costly to repair. Industry peer utilities report similarly poor service life experience from this model circuit breaker.

  In general, where significant repair is required, the preference is to replace the circuit breaker.

  Some common issues for the population include:
  - Irreparable gas leaks – gas leaks through cast housing components, repair is not feasible and asset replacement is required to prevent ongoing leaks and top ups for the remaining service life.
  - Mechanism failures – mechanical component failure has resulted in replacements of the whole mechanism.
  - High moisture in SF6 – Industry peers report frequently finding high moisture from commissioning.
  - Polymer insulation sheds showing significantly accelerated environmental deterioration
  - Bushing are fragile, susceptible to cracks – Bushing replacement parts are very expensive.
- Many Alstom GL315 & GE FXT15 330kV CBs on reactive plant with POW switching applications have experienced POW relay alarm which indicates there are periodic CB operations that are outside of the relay tolerances.
  - During POW relay checks performed by Works Delivery control technicians on Sydney North No.4 capacitor bank, the technician reported experiencing variable timing within 10 consecutive

operations. The variability was beyond the setting capability of the relay to adapt to and the relay produced an alarm representing an ineffective POW relay operation occurred.

- Tamworth No.1 Capacitor Bank circuit breaker was investigated after experiencing the alarm several times. Control technicians investigated the POW relay and determined it was operating within parameters. Substation maintenance technicians investigated the CB separately and determined it was operating within parameters.
- Similar alarms were identified on Kemps Creek No.1 & No.2 capacitor bank circuit breakers. Investigation works were dispatched on both CBs which were to include CB testing together with the relay in conjunction with the manufacturer to determine the root cause and options to address the issue. These investigations are outstanding.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 12: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Circuit Breaker asset health has been evaluated to determine the effective remaining life adjusted by condition parameters for the total population Factors such as those described in section 5.5.2 are taken into account in the evaluation of individual asset health.	RP2 Renewal initiative: Replace 208 circuit breakers based on economic and ALARP/SFAIRP evaluations to address associated risks.	RP2 - Ongoing 91 of 208 Completed	Need No: 1337
			RP3 Renewal initiative: Replace 130 circuit breakers based on economic and ALARP/SFAIRP evaluations to address associated risks as well as a small number as part of larger replacement projects.	RP3 (2023 – 2028) – Commencing 2023	Need No: N2345
Dead Tank Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	There is benefit in installing Dead Tank CBs with the elimination of separate post current transformers eliminating their associated failure risk and maintenance costs DTCBs present maintenance cost saving, reduction in future outages and reduced operational risk	Replacement of circuit breakers with dead tank type when circuit breaker replacement is required and the associated current transformers also have significant risk.	Ongoing	D2015/07219: Issue Paper – Dead Tank CBs
SF6 Circuit Breakers	• Manage network safety risk	Emergence of recurring or unrepairable SF6 leaks from Circuit Breakers	Renewal initiative: Replace circuit breakers with unrepairable SF6 leaks as identified.	Ongoing 1 CB identified to date - Completed	Need No: 1337

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value		To be managed through Management of SF6 Gas procedure with asset renewals to be incorporated into asset renewal programs as identified.		
SF6 Circuit Breakers	• Manage network safety risk • Manage assets efficiently to deliver security holder and consumer value	UNFCCC - Paris Agreement; impact on SF6 emissions and holdings CB designs have become commercially available which include vacuum interrupters up to 132kV combined with non-SF6 insulation, however they come at a cost premium to conventional arc in SF6 designs	Asset manager to undertake further analysis: Review Substation Renewal and Maintenance Strategy based on outcome of agreement and Government/Regulatory requirements. Procure a small population of circuit breakers utilising alternative insulation methods to SF6.	Under development.	Need N2345
Reactor Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	High component wear rate and increased failure risk of circuit breakers installed in reactor bays.	Asset manager to undertake further analysis: Review options to improve lifecycle cost of transformer tertiary connected 33kV Air Reactor CBs and monitor switching wear of the CB TG206329 at Kemps Creek.	Ongoing	Need No: N2615 D2003/2312 – Maintenance Plan – Substation Assets

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
			Maintenance Initiative: Periodic overhaul of non-POW CBs at 1000 operations.		Need No: N2342, N2638 D2003/2312 – Maintenance Plan – Substation Assets
Alstom OX36 Dead Tank Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Alstom OX36 Circuit Breaker population exhibit premature deterioration of condition, high defect rate and cost for population.	Asset Manager to undertake further analysis: Monitoring of the performance and condition of the OX36 population to determine viability of defect repair and optimal renewal timing. Consider application of 'type issue' health index score application to population for forward health index evaluation.	Under Development	N/A
330kV Reactive Plant POW Switching Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Alarms from the associated POW relays indicate a periodic fault in performing an effective POW operations. The root cause and options to address the fault are unknown.	AIM issues and associated work orders have been provided to Works Delivery to investigate the faults, determine the root cause and identify options to address the issue in line with the Corrective Maintenance Process	In Progress	AIM Issues: 240827 240826 D2017/01717 – Corrective Maintenance Process

5.5.3. Maintenance Program – Circuit Breakers

Circuit Breakers are primarily mechanical devices with significant impacts in the case of failure. Routine maintenance activities are structured to derive full operating functionality from each unit for the duration of their design life. However, it is clear that individual units can develop problems requiring specific treatment or maintenance requirements. Where issues are identified, maintenance activities will be modified in order to collect sufficient information and measurement data to support thorough continuing analysis.

In the main, Routine Maintenance activities are designed to identify abnormalities with Circuits by comparing measurement data and inspection information with limits and requirements described in D2014/19504 - Substation Condition Monitoring Manual. Where an abnormality exceeds a predetermined allowable value, a range of escalated actions are described, designed to address each abnormality.

Transgrid will collect the range of measurement data required for analysis through the use of routine, scheduled inspections and planned offline maintenance activities consistent with the following principles:

- Maintenance is to be minimised consistent with reliable plant performance
- Maintenance costs are to be minimised consistent with corporate objectives of safety, reliability, availability and risk management.
- To ensure compliance with limits for acceptable equipment service condition documented in the Substation Condition Monitoring Manual (and manufacturer’s manual where applicable)
- Condition monitoring by external diagnostic testing is preferred to disassembly and inspection.
- Implementation of new technology to develop continuous on-line condition monitoring systems is to be pursued where benefits can be achieved consistent with the aforementioned principles.
- New plant is to be of a proven safe, reliable and low maintenance design fitted with online monitoring devices where benefits have been identified.

5.5.3.1. Component Failure Risk Assessment - Circuit Breakers

A component failure risk assessment has been conducted for the Circuit Breaker asset class and is shown in the table below. The analysis is compared with the Substation Maintenance Plan for the asset class to demonstrate alignment between potential component failures and preventative maintenance activities prescribed to diagnose them.

Table 13: Component Failure Risk Assessment – Circuit Breakers

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Planned maintenance**	**OLCM**	**Business Plan Objectives**
Mechanism including trip coils, operating rods and linkages	Failure to operate	Uncleared fault Inability to restore load	2	2	4	Inspection - particularly in bottom of mech box	Timing, operation checks, mech checks	Timing measured on each operation. Coil currents	Safety Reliability Environment
	Latching issues	uncleared fault Inability to restore load	2	2	4	Inspection	Timing, lubrication, operation checks, mech checks		
	Slow operation	System impact	2	1	2	Inspection	Timing, annual operation, travel analysis, lubrication.		
	Pole discrepancy (eg: failed operating rod)	CB failure	1	3	3	Inspection (will not help operating rod)			
	Damping failure	CB damage and failure	2	2	4	Inspection	Timing		
Interrupters	Worn contacts	CB failure	2	3	6		Timing, dynamic contact resistance, micro-ohm	gas pressure alarms, gas pressure	Safety Reliability

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Planned maintenance**	**OLCM**	**Business Plan Objectives**
	Punctured arc shield/ damaged turbulator	CB failure	1	3	3	internal as appropriate	SF6 analysis	monitoring, Timing on each operation	Environment
	High contact resistance	CB failure	3	1	3		micro-ohm		
	Contamination of insulating fluid	CB failure	1	3	3		IR, SF6 analysis		
	Leaking grading capacitors	uncleared fault	3	1	3	inspection			
	Failure of porcelain	CB failure	1	3	3	inspection			
	Leaks - low pressure or low oil	CB failure	3	1	3	inspection			
Insulation	Contamination of insulating fluid	CB failure	1	3	3		IR, SF6 testing	gas pressure alarms, gas pressure monitoring	Safety Reliability Environment
	Tracking	CB failure	1	1	1		IR		
	Porcelain Failure	CB failure	1	3	3	inspection			
	Leaks	CB failure	3	1	3	inspection	Topped up		

			Risk			Preventative			Linkage
Component	Problem	Outcome	Likelihood	Consequence	Rank	Inspection	Planned maintenance	OLCM	Business Plan Objectives
Control	Stuck SF6 Gauge Contacts	CB failure	2	1	2	inspection	Functional checks	gas pressure alarms and monitoring	Safety Reliability Environment
	Failure of mechanism interlocks	Inability to restore load	2	1	2		Functional checks, Annual operation.	CB status alarm	Safety Reliability Environment

5.5.3.2. Maintenance Program Amendments – Circuit Breakers

Circuit Breaker maintenance was reviewed previously and changes in frequency were made based on a consideration of the above risks. The objective of the change is for efficiency gains in the delivery of equipment maintenance.

The changes in maintenance affecting Circuit Breakers include:

- A reduction in inspections.

  Substation inspections are now scheduled at 6 monthly intervals for most substations and 12 months for substations less than 10 years old. The impacts on transformer reliability arising from this are expected to be minor. From the table above, the items impacted by inspection maintenance are lower ranked risks.

- An extension of the time between detailed inspections.

  The interval for detailed inspections of SF6 interrupter live head design and Mitsubishi Dead Tank design circuit breakers was formerly 4 years and this has been extended to 6 years, excluding reactive plant circuit breakers.

  - Circuit breakers within this group which have OLCM devices fitted will not require this maintenance.
  - Reactive plant circuit breaker detailed inspections are not performed due to shorter timeframe minor maintenance intervals.

- An extension of the time between minor maintenances.

The interval for minor maintenance of all non-reactive plant circuit breakers has been extended.

  - Minor Maintenance for SF6 live head and dead tank design circuit breakers was formerly 8 years and this has been extended to 12 years.
  - Minor maintenance for oil filled and vacuum circuit breakers was formerly 4 years and has been extended to 6 years with emphasis on the need to correctly monitor operation duty through cyclo readings in order to schedule operations based maintenance.
  - Circuit breakers within this group which have OLCM devices fitted will not require this maintenance.

Details of the changes are included in AMI-AS0001 – Maintenance Plan Amendments July 2016 in file D2016/10692.

5.5.4. Online Condition Monitoring – Circuit Breakers

Where already fitted the likely benefits occurring from online condition monitoring systems and in particular the potential for improved reliability and availability of Substation Plant are to be considered when identifying appropriate maintenance activities for Circuit Breakers. Where reliable on-line systems are in place, certain periodic diagnostic or invasive maintenance requirements may become redundant.

Where online condition monitoring systems are installed, identified maintenance routines will be amended with the approval of the Asset Manager. Minimum prerequisites for such amendments are:

- Installation of reliable sensors
- Adequate communication systems to facilitate the collection of condition monitoring data,
- Robust systems for the specification and implementation of settings and alert thresholds, and

- Effective asset management processes, resources to monitor, assess, and action the on-line condition monitoring data.

5.6. Gas Insulated Switchgear (GIS) Asset Review

5.6.1. Population Review

Gas Insulated Switchgear (GIS) installations are in service at six sites:

- Beaconsfield West substation was commissioned in 1979 containing a single 132kV GIS installation. The installation has been decommissioned following the commissioning of two 132kV GIS installations at Beaconsfield North and Beaconsfield South in 2012.
- Haymarket substation was commissioned in 2004 and contains a 330kV and a 132kV GIS installation.
- Holroyd substation was commissioned in 2014 and contains a 330kV GIS installation.
- Rookwood substation was commissioned in 2014 and contains a 330kV and a 132kV GIS installation.
- Taree substation 33kV switchboard was commissioned in 2018 is an MV fixed pattern metalclad design.
- Orange substation was commissioned in 2018 and contains a 66kV GIS installation.

5.6.2. Emerging Issues, and Renewal and Maintenance Initiatives

The emerging issues for GIS equipment are as follows:

- Maintenance of GIS was in the past based on air insulated switchgear. The number of GIS sites has expanded and a targeted maintenance approach has now been included in the maintenance plan in recognition of the different requirements and performance of GIS equipment.
  - Through attempts to deliver prescribed maintenance activities on MV metal clad switchboards with a fixed pattern design, WD have identified difficulties in obtaining circuit breaker timing measurements through conventional testing methods. The Maintenance Plan – Substation Assets has been updated to identify the option to deliver circuit breaker timing through alternative methods.
- A number of GIS chambers are being identified through the online condition monitoring data as having slow SF6 leaks. Leaks are an ongoing concern from a reliability, cost and environmental impact standpoint, however leak rate data suggests that even minute leaks exist from every chamber and increased leaks can develop through the operating life of the equipment.
  - Leaks have been identified in majority of GIS installation through online condition monitoring and have been addressed as warranty repairs. Warranty repair provides a significant cost benefit to Transgrid in managing early life leak defects
  - The majority of GIS installations have now moved out of their respective warranty periods
  - As described in section 5.5.2, the Paris Agreement may have an impact on SF6 utilised as the insulation medium within GIS installations.
- In 2017 a fast leak developed on the Haymarket 132kV GIS and was located to a busbar chamber barrier board. Through repair of this leak and subsequent investigations, a number of barrier boards have been identified with cracks.

- Transgrid have engaged the manufacturer to facilitate repair of the leaks, investigate the extent of the issue and provide a root cause analysis (RCA) report. This report is expected to provide recommendations in managing the risk and impact on the whole 132kV GIS installation.
- Factors external to the GIS are being investigated for contribution to the barrier board failures. Investigations include GIT vibration and coupling to the GIS, as well as movement in the suspended concrete slab floor.
- The manufacturer has recommended utilising the embedded UHF PD sensors to periodically monitor for signs of barrier board deterioration. This has been included in the 2020 update of the Maintenance Plan – Substations Assets.
- A package of work has been scoped for the manufacturer to replace remaining affected barrier boards to return the switchboard to full rated capacity. This work will also include further root cause investigation that is expected to inform the long term strategy for managing further barrier board cracks.
  - The COVID-19 pandemic has caused logistics delays to the completion of this work package. Works are currently planned for completion in late FY 22, with analysis and development of recommendations in consultation between the manufacturer and Transgrid to follow.

- Beaconsfield 132kV GIS and GIL installations have developed a number of chamber leaks. Investigations are underway into scoping the repair of these defects. The majority of defects have developed from the GIL which is weather exposed, as compared to the GIS which is installed fully indoors.
  - 3 leaks have been identified as originating from the pressure relief device flange. These have been rectified through defect WOs with support from the manufacturer.
  - The manufacturer analysed the root cause of the gas leak and identified an issue with the design of the rupture disc assemblies.
  - The manufacturer has offered free issue of a revised design assembly however there is significant internal labour cost in replacing all units.
  - Asset Management has issued a package of work to replace rupture disc assemblies on 1 complete GIL and a report on findings relating to prevalence of moisture ingress issues that may lead to future leaks. This reporting is to inform the benefit of completing replacements on the entire installation.
  - A 4^{th} leak on the GIL has been located at chamber flange. The scoping of the repair with manufacturer support.is underway.
    - The COVID-19 pandemic has caused logistics delays impacting the completion of this work package.
- An arc flash hazard was reported by Works Delivery arising from a Siemens 8DA10 switchboard. This prompted a review of the arc flash hazards associated with all indoor switchboards (11-33kV).
  - Initial investigations identified aspects of the switchboards which were not arc flash rated and had interim measures put in place to restrict access to these aspects while the extent of the hazard and solutions are being investigated.
  - The investigation has also identified a potential issue and need to review the effect of building over pressure arising from an arc flash event. This has been incorporated into the arc flash investigation.

- The investigation has been completed, identifying the hazard levels and work methods required to control the hazard, allowing room and equipment access.
- Further works are being evaluated to reduce the arc flash and improve building over pressure hazard mitigation.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 14: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Haymarket 132kV GIS	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	A number of gas compartment barrier boards have been identified with cracks	A project has been issued for the investigation of root cause, repair of fractured barrier boards, return the installation to normal rating capacity and further monitoring or mitigations requirements.	IWR-0177 – Complete IWR-0206 – Complete pending reporting close out. Need 2246 – In progress	IWR-0177 IWR-0206 Need 2246
Beaconsfield 132kV GIS & GIL	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	A number of gas compartments have been identified with SF6 leaks that need to be addressed.	Maintenance Initiative: Defect work orders have been issued to scope the repairs.	Ongoing 3 rupture disc assembly leaks repaired. 1 remaining insulator flange leak remains to be repaired.	D2017/01717 – Corrective Maintenance Process
Beaconsfield 132kV GIL - Rupture Disc Assemblies	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Root cause investigation of the rupture disc assembly leaks identified a weakness in the design associated with water ingress leading to flange corrosion and gas leaks.	Maintenance Initiative: An IWR has been issued to replace all rupture disc assemblies for 1 complete GIL and provide reports on observations and recommendations to undertaken further works.	Site works completed. IWR reports and recommendations pending.	IWR-N2354

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
MV Fixed Pattern Metalclad Switchboards	• Manage network safety risk • Maintain network reliability	Access to perform routine maintenance timing testing through primary contacts is difficult to achieve with the fixed pattern design switchboards.	An option to deliver timing through alternative test methods have been identified for MV Switchboards in the Maintenance Plan - Substation Assets.	Implemented	D2003/2312 Maintenance Plan – Substation Assets
MV (33kV) Metal Clad Switchboards	• Manage network safety risk • Maintain network reliability	Arc flash investigation into arc flash safety hazard and building over pressure have not been assessed during project design. Investigation of hazard and recommended solutions to mitigate risk are required. Improvement to the SDM is required to ensure arc flash hazards are identified and mitigated.	IWR-0209 has been raised to investigate the hazard and determine a recommended solution.	Hazard reports completed and communicated for implementation. Further work scoping in progress.	AS IWR-0209
GIS Circuit Breakers	• Manage network safety risk • Manage assets efficiently to deliver security holder and consumer value	SF6 leaks are being identified from GIS chambers, identified by online condition monitoring devices through density trending.	Asset manager to undertake further analysis: GIS allowable leak rates Maintenance focus: Corrective works issued for excessive leak rates as identified.	Ongoing	D2003/2312 – Maintenance Plan – Substation Assets

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
GIS Circuit Breakers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	UNFCCC - Paris Agreement; impact on SF6 emissions and holdings.	Asset manager to undertake further analysis: Review Substation Renewal and Maintenance Strategy based on outcome of agreement and Government/Regulatory requirements.	On Need	N/A

5.6.3. Maintenance Program – GIS

Based on the overall performance of the GIS asset fleet to deliver the required overall network reliability and performance levels and the effectiveness of the current maintenance and inspection activities to identify and address current and emerging issues in the past, a reduction in GIS maintenance is proposed and approved in June 2015, refer to Proposal on Maintenance Savings (D2015/06734) and GM AS S1 001 Maintenance Plan – Substation Assets for details.

The introduction of MV fixed pattern metalclad switchboard design installations has prompted consideration of maintenance requirements for this type of GIS installation.

- Manufacturers typically refer to this type of design as being “maintenance free”; this is supported by reported high reliability and also demonstrates that the design does not prioritise intrusive maintenance activities.
- The absence of recommended measurement parameters to support condition evaluation is noted as a longer term risk for monitoring health and renewal justification. Engagement with industry peers is considered critical in monitoring performance of large populations of this type of asset design to determine drivers and methods for intervention.
- Minor maintenance scope prescribed is minimally invasive and is performed at the same frequency as typical GIS.
- There is presently no major maintenance scope for this type of installation.

5.6.4. Online Condition Monitoring – GIS

All Transgrid’s GIS installation 66kV and above are fitted with SF6 gas density monitors, most of which are connected to OLCM central server. There have been a number of instances where SF6 gas leaks from GIS compartment were detected by OLCM system. On line monitoring of gas compartment pressure has been very effective in enforcing warranty leak repair requirements on GIS suppliers avoiding significant repair costs requiring manufacturer to scope work methods and deliver the repairs with factory trained staff.

5.6.5. Disposal Initiatives – GIS

Disposal of aged or no longer needed GIS equipment will follow an approved Asset Disposal process where re-use is no longer feasible. Asset disposal will include decommissioning of the asset, and decisions on whether to sell as scrap or dispose at a waste management facility. The process shall also address the following related issues:

- Safe work practices during de-commissioning and dismantling
- Appropriate probity considerations
- Consideration of environmental risks associated with remaining aged insulating oil or gas
- Requirements for treatment and re-use of SF6 gas

5.7. Instrument Transformers Asset Review

5.7.1. Population Review – Instrument Transformers

Transgrid manages a total instrument transformer population of approximately 5,676 units ranging in voltage from 11kV to 500kV. The instrument transformer population is comprised of:

- 3169 Current Transformers (CT) – this accounts for approximately 55.8% of the total population.
- 2507 Voltage Transformers (VT), this accounts for approximately 44.2% of the total population which comprise of:
  - 1,580 Capacitor Voltage Transformers (CVT),
  - 924 Magnetic Voltage Transformers (MVTs),

All of the CTs are of the post freestanding type i.e. any instrument transformers embedded within metal clad switchgear, gas insulated switchgear, power transformers and oil filled reactors are not included in the above statistics.

The majority of post type CTs are constructed of oil-paper insulation, although SF6 insulated equipment has been installed since the 1990's. There are also a small number of solid insulated (epoxy) instrument transformers.

The current transformer age profile is shown in the Figure 28. The population of post type CTs have declined 4.7% from 2020 as new installations have CTs imbedded in DTCB and some of the older units are also being replaced with Dead Tank CB where feasible. Age profile also shows that approximately 3% of the units were commissioned before 1981, and have thus exceeded their nominal lifespan of 40 years. The oldest units were manufactured in 1963. The current transformers have an average age of approximately 16.6 years.

Figure 28: Current transformer – Age profile

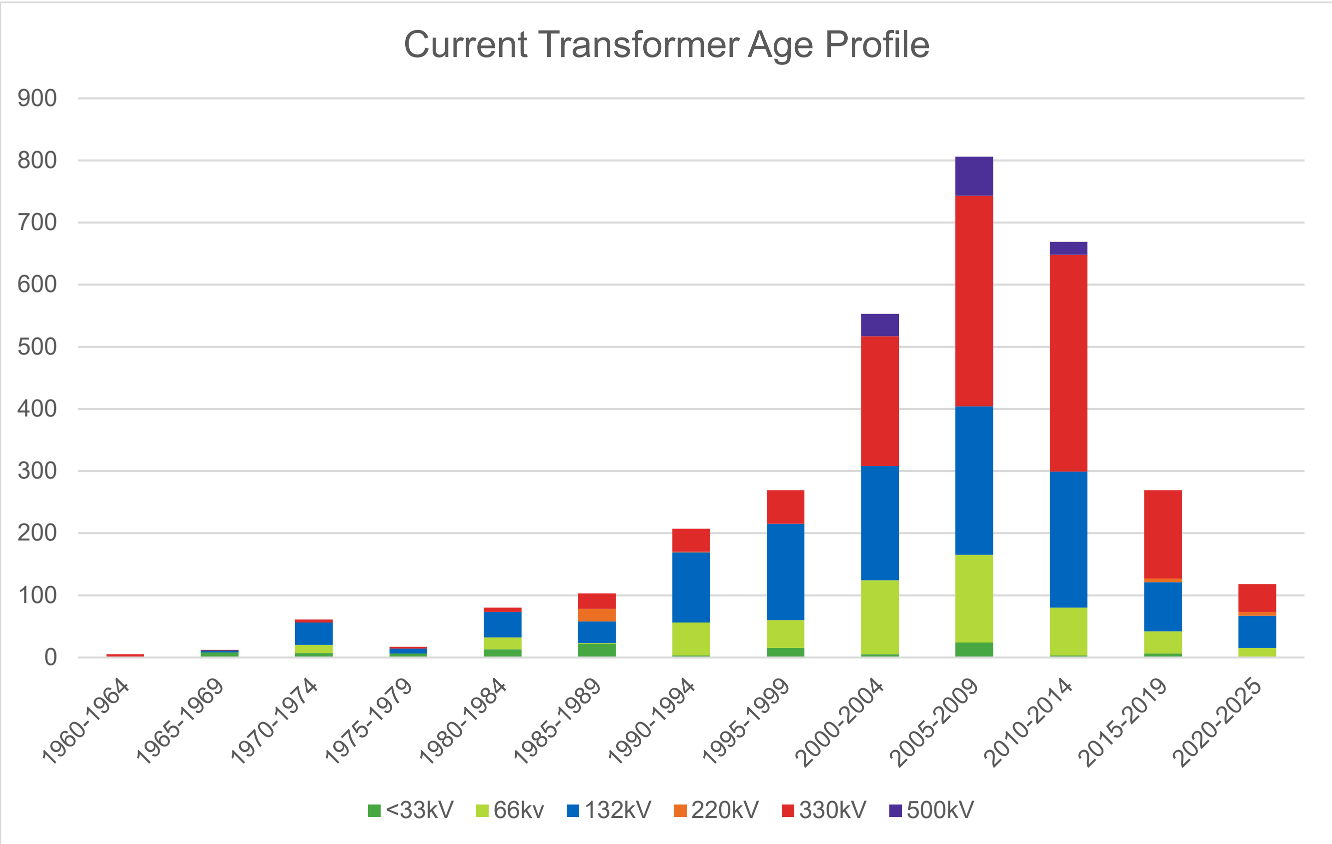
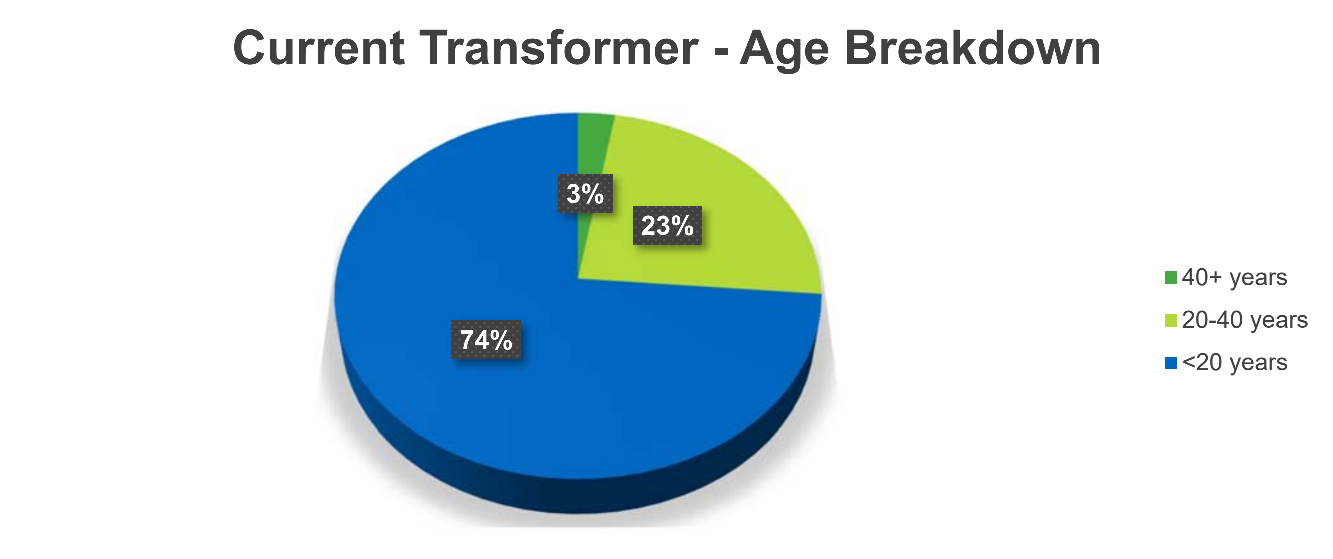
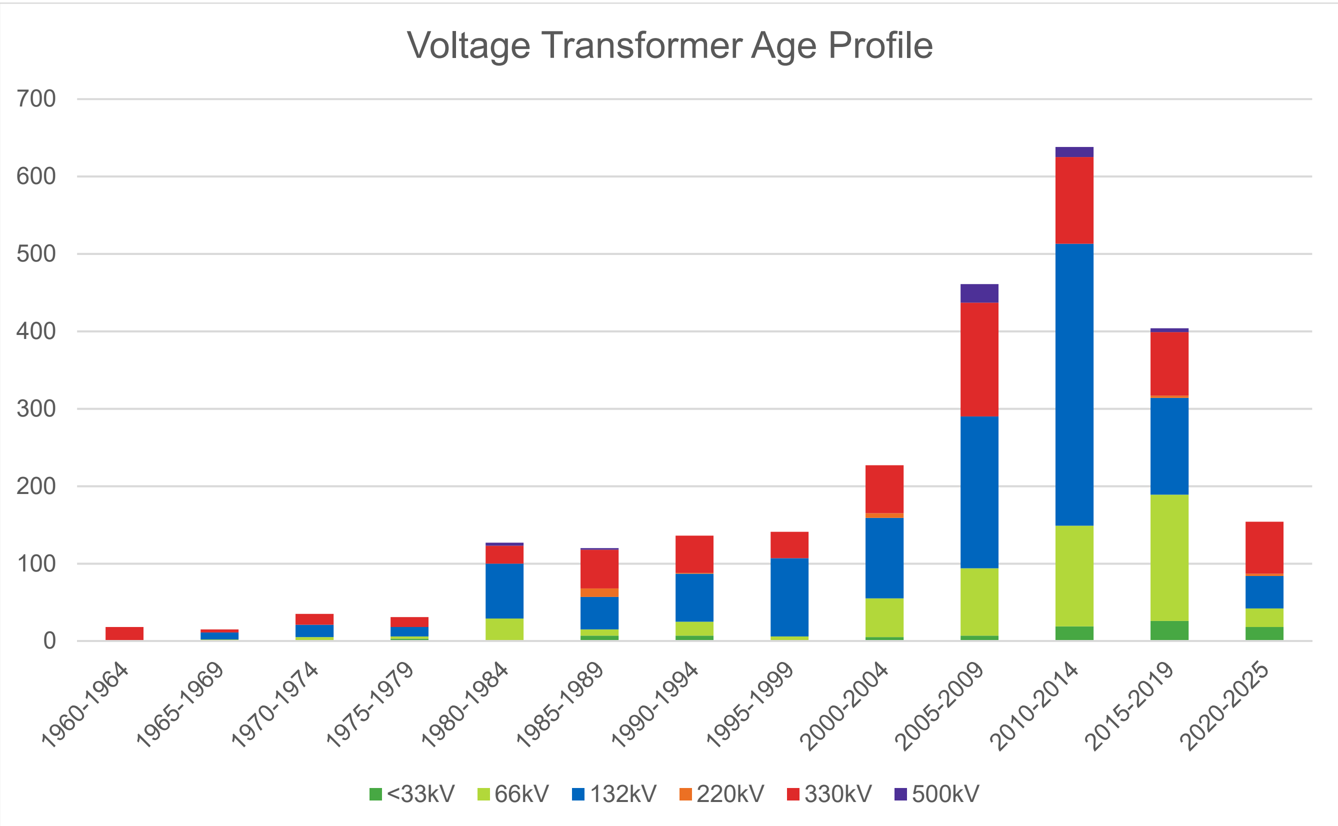


Figure 29: Current transformer – Population Age Breakdown



The voltage transformer age profile is shown in Figure 30. Age profile shows that approximately 5.2% of the units were commissioned before 1981, and have thus exceeded their nominal lifespan of 40 years. The oldest units were manufactured in 1960. The voltage transformers have an average age of approximately 15.7 years.

Figure 30: Voltage Transformer – Age profile



Instrument transformers are in general, considered to be reliable and low maintenance items of plant. However, they are at high risk of catastrophic failure, especially older oil filled units. There is associated risk to personnel in the vicinity due to shards of porcelain ejected with great energy. This type of failure presents unacceptable safety risks and maintenance programs are designed to monitor instrument transformer condition and avoid this type of failure while minimising cost.

5.7.2. Emerging Issues, and Renewal and Maintenance Initiatives – Instrument Transformers

The instrument transformer population has been affected with changes in technology over time and the following categories exist:

5.7.3. Older Instrument Transformers

There are some general issues with older oil filled instrument transformers that are common amongst manufacturers, type and age. Such as:

- Older oil-filled instrument transformers are generally fitted with rubber-cork gasket seals. These seals become brittle with age and movement may cause them to split and leak. Workshop overhaul may be required to address a leak and this type of facility is not generally available/economic.
- Some older instrument transformer types are fitted with brass or synthetic rubber expansion bellows to allow oil expansion while excluding atmosphere and water. These bellows may crack and are generally not replaceable.
- Corrosion of steel components may result in leaks or intrusion of water, which will cause catastrophic failure if not addressed.
- A problem exists with gate valve sample points on older oil filled instrument transformers that is believed to result in water contamination of oil samples, making water content measurement unreliable for these units.

These transformers are monitored through DGA. When an oil sample indicates elevated combustible gasses, action is taken depending on the levels found. Levels in excess of monitoring limits will typically result in additional oil sampling – with additional impacts on outages and maintenance work. This may be particularly significant for critical or radial supplies. Elevated gas levels indicate that the affected instrument transformer is at high risk of developing a fault that will lead to explosive failure. Higher combustible gas levels may require immediate replacement.

However, it is to be noted that some oil filled instrument transformers such as RITZ, are not designed for regular oil sample and therefore routine IR and DDF testing are used as diagnostic methods to monitor their condition.

5.7.4. Older Current Transformers with porcelain insulators

Post type CTs prior to the 1990s will generally be of an oil insulated hairpin type construction fitted with a porcelain insulator. These types pose the most significant risk to safety, reliability and potential environmental damage. Insulation failure of these types will result in the release of large amounts of energy and ejection of porcelain at high velocity. These units are presently the greatest concern with regard to the DGA gas levels and oil leaks/deterioration. They also represent a large group in the instrument transformer population. Repair or refurbishment of these units is not feasible and as the units age, more aggressive replacement action may become necessary. These units are progressively being replaced under CT renewal programs.

Current Issues:

- Non-standard CTs: Some older current transformers may not have suitable ratios, requiring the use of interposing CTs
- Type issues: There have been cases where groupings of instrument transformers are considered suspect, due to failure history or known type issues related to design faults or manufacturing quality control issues. In these cases, the affected units may be considered at higher risk of failure and if of the oil filled type, may be prone to fail explosively.
- Data about accuracy and ratio is not available for all current transformers, which makes it difficult to determine suitable spares requirement.

5.7.5. Older oil insulated MVTs with porcelain insulators

These units have generally been reliable but the failure consequence can be severe. These units are affected by leak issues as described under hairpin CTs above. DGA monitoring is also used although this is not possible for a relatively small number of 66 kV MVTs where no sampling point has been provided. These MVTs are expected to be replaced by the end of RP2.

5.7.6. CVTs using porcelain/polymer insulators

Older CVTs are manufacturer with porcelain insulators where newer units are manufactured with polymer insulators. CVTs are generally reliable although type issues are appearing in older types. Their failure modes are listed below:

- Cascade failure of the capacitor elements used to divide the high voltage is a typical failure mechanism for CVTs and this is managed using a monitoring system as described below.
- Other issues may arise that are related to the magnetic unit at the base of the CVT. These can include:
    - Ingress of water.
    - Ferroresonance problems causing overheating and failure.
    - Tracking on the secondary terminal board.
- Known problems exist on certain models of CVTs manufactured by TRENCH and HAEFELY. The type issues are accounted for in the health index calculation and the outcome is a strong weighting toward replacement of these types.

Monitoring of CVT condition is reliant on detection of faults through on-line monitoring of secondary voltage imbalance. However, older CVTs are also managed through planned replacement program due to their high risk and known type faults.

5.7.7. Gas filled Instrument Transformers

Gas filled CTs and MVTs with polymer insulators which have been supplied since the mid-late 1990s are considered to have a low failure consequence. The CTs are live head type with smaller cores than traditional hairpin types.

- SF6 instrument transformers may develop leaks over time and this will need to be managed to ensure the reliability of equipment and to manage the cost and environmental impact of SF6. There is an example of this which is related to a type issue for a particular CT model i.e. Trench CTs.

- Trench 330kV CTs at Liddell and Kemps Creek have failed with similar root cause of internal flashover. The investigation of Kemps Creek CT is underway and upon completion the strategy can be developed for this type of CT.
- Gas Pressure monitoring: Faults have been found in gas pressure switches on gas filled current transformers. Faulty gauges or switches will be rectified on a defect basis.

5.7.8. Small oil volume polymer insulator Instrument Transformers

Newer oil filled CTs and MVTs contain small oil volumes with polymer insulators. These are also considered to have a low failure consequence. The CTs are live head type with smaller cores than traditional hairpin types.

Routine testing scope for polymer insulated small oil volume CTs requires review:

- Small oil volume and polymer insulation design reduces failure risks.
- Supplied oil volume is often not sufficient for routine oil sampling throughout the service life of the asset.
- Live head CT designs typically have small capacitances, resulting in unreliable DDF test results.

Some cases have been found where secondary insulation resistance on CTs has fallen to levels that threaten the reliability of protection systems and could result in false tripping or failure to trip for a fault. Therefore secondary IR test is now included on need basis, instead of routine tests.

5.7.9. Epoxy Resin Instrument Transformers

There are a small number of epoxy insulated units at voltages up to 66 kV with majority of epoxy resin insulated instrument transformers are rated 33 kV and below.

5.7.10. Instrument Transformer Failure Risk

Transgrid utilises health index methodology to assess instrument transformer condition using available asset information data to estimate failure risk; demonstrate any requirement for action; and to rank the priority of work. The below factors are used to evaluate instrument transformers health index (HI) include:

- DGA
- Moisture
- Type issues
- Age

This method cannot be applied to epoxy or gas instrument transformers or to CVTs as there is no useful condition data available to assess. For these assets the failure risk is based on installation or manufacture year. Gas and epoxy types have not developed major issues at this point and CVTs have a monitoring system as described above.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 15: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Current Transformers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Current Transformer asset health has been evaluated to determine the effective remaining life adjusted by condition parameters for the total population. Aged based condition issues including leaks Hairpin type CTs assessed as being closer to end of life in health assessment process. Priority will be given for early replacement of key types (e.g. Tyree 330kV CTs) DGA levels are monitored and are used in health index and to initiate urgent replacements if required.	Health Index (HI) data combined with Probability of Failure and criticality data identified assets with positive cost benefit evaluation for renewal when weighed against evaluated ongoing risk cost. Renewal initiative: Replace CTs based on economic and ALARP/SFAIRP evaluations to address associated risks. CTs requiring replacement installed next to a CB also requiring replacement will result in a combined DTCB, and are not included in this quantity.	RP2 (2018-23) - Ongoing Replaced: 167/322	Need No: 1338
				RP3 (2023 – 2028) – Commencing 2023	Need No: N2347
Voltage Transformers	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Voltage Transformer asset health has been evaluated to determine the effective remaining life adjusted by condition parameters for the total population. CVT type issues on Trench and Haefely included in population risk assessment	Health Index (HI) data combined with Probability of Failure and criticality data identified assets with positive cost benefit evaluation for renewal when weighed against evaluated ongoing risk cost.	RP2 (2018-23) - Ongoing Replaced: 122/241	Need No: 1442
				RP3 (2023 – 2028) – Commencing 2023	Need No: N2348

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
		VTs without sampling points assessed based on age to determine risk level. DGA levels are monitored and are used in health index and to initiate urgent replacements if required.	Renewal initiative: Replace Voltage Transformers based on economic and ALARP/SFAIRP evaluations to address associated risks.		
Current Transformers - Polymer Insulation	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Small oil volume of polymer insulation design reduces failure risks. Supplied oil volume is often not sufficient for routine oil sampling throughout the service life of the asset. Live head CT designs typically have small capacitances, resulting in unreliable DDF test results.	Asset Manager to undertake further investigation: Assess routine testing scope for population.	Investigation underway	
NCIT	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Non-conventional instrument transformers may provide a cost effective solution compared to traditional asset replacements.	New technology investigation into non-conventional ITs are underway	In progress	Need 1578
330kV Trench CT failures	• Maintain network reliability	Repeated failure may be an indication of type fault.	Finalise investigation into second failure at Kemps Creek and ensure current renewal and maintenance strategies are adequate.	Investigation underway	

5.7.11. Maintenance Program – Instrument Transformers

Instrument Transformers are relatively low cost items and routine maintenance activities are structured to derive full operating functionality from each unit, for the duration of their design life. However, it is clear that individual units can develop problems requiring specific treatment or maintenance requirements. Where issues are identified, maintenance activities will be modified in order to collect sufficient information and measurement data to support thorough continuing analysis.

Routine Maintenance activities are designed to identify abnormalities by comparing oil sample data, inspection information and offline diagnostic data with limits and requirements described in the Substation Condition Monitoring Manual – GM AS S1 008. Where an abnormality exceeds a predetermined allowable value, a range of escalated actions are described, designed to address each abnormality.

Specific initiatives will address concerns associated with instrument transformer insulation systems, determined by:

- Insulating oil quality, dissolved gas and moisture content (where oil sampling is possible)
- Capacitance and Tan δ measurements (where measurements are possible)
- Mechanical considerations (corrosion, oil leaks)
- SF6 Insulating gas leaks and gas quality – where poor quality is indicated

Online Monitoring – Where the insulating medium is SF6, online monitoring of the gas density will be implemented for all new instrument transformers, to enable Transgrid to meet the 0.5% Annual Gas Loss target and manage low gas call-out frequencies. The Asset Manager may amend Maintenance routines based on experience with SF6 monitoring systems and benefits have been identified.

5.7.12. Component Failure Risk Assessment – Instrument Transformers

A component failure risk assessment has been conducted for the Instrument Transformer asset class and is shown in the tables below. The analysis is compared with the Substation Maintenance Plan for the asset class to demonstrate alignment between potential component failures and preventative maintenance activities prescribed to diagnose them.

Table 16: Component Failure Risk Assessment – Oil Filled Instrument Transformers

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Oil sampling**	**Planned maintenance**	**Business Plan Objectives**
Main insulation system	Insulation breakdown, type fault	Failure of IT*	2	3	6		DGA, oil moisture	IR, DDF, Capacitance	Safety Reliability Environment CAPEX Performance STPIS Performance
	Water or other contamination	Failure of IT*	1	3	3				
	DLA point unearthed (CT only)	Damage to insulation leading to failure of CT*	1	3	3	Inspection			
	Corrosion of metal housing, breakdown of paint system, failure of gaskets	Damage to IT leading to contamination	1	1	1	Inspection	DGA, oil moisture	IR, DDF, Capacitance	
Palm and head of IT	Poor HV connection leading to overheating and damage to IT	Damage to IT, potential failure	1	2	2	Thermovision			
	Functional failure of component, contamination,	Damage to IT, reduction in insulation functionality	1	1	1	Inspection			

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Oil sampling**	**Planned maintenance**	**Business Plan Objectives**
	undetected leaking								
Bellows, gauges etc.	Undetected loss of insulation	Failure of IT*	1	3	3	Inspection			
Cores	Failure leading to CT error or protection failure	Uncleared fault	1	2	2			IR during protection maintenance	Reliability STPIS Performance

* Porcelain insulator is assumed here which increases the consequence of failure

Table 17: Component Failure Risk Assessment – Gas Insulated Instrument Transformers

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Planned maintenance**	**OLCM**	**Business Plan Objectives**
Main insulation system	Insulation breakdown, type fault	Failure of IT	1	2	2		Gas decomposition		Safety Reliability Environment CAPEX Performance STPIS Performance
	Water or other contamination	Failure of IT	1	2	2		Dewpoint		
	Corrosion of metal housing, breakdown of paint system, failure of gaskets	Damage to IT leading to contamination	1	2	2	Inspection		Gas pressure alarm	
Palm and head of IT	Poor HV connection leading to overheating and damage to IT	Damage to IT, potential failure	1	1	1	Thermovision			
Gas Pressure gauge	Undetected loss of insulation	Failure of IT	1	2	2	Inspection	Test gauge	Gas pressure alarm	
Cores	Failure leading to CT error or protection failure	Uncleared fault	1	2	2		IR during protection maintenance		Reliability STPIS Performance

Table 18: Component Failure Risk Assessment – CVTs

			Risk			Preventative			Linkage
Component	**Problem**	**Outcome**	**Likelihood**	**Consequence**	**Rank**	**Inspection**	**Planned maintenance**	**OLCM**	**Business Plan Objectives**
Main insulation system - capacitor section	Insulation breakdown, type fault	Failure of CVT	2	3	6			CVT unbalance monitoring	Safety Reliability Environment CAPEX Performance STPIS Performance
	Water or other contamination	Failure of CVT	1	3	3				
	Corrosion of metal housing, breakdown of paint system, failure of gaskets	Damage to CVT leading to contamination	1	3	3	Inspection			
Main insulation system - magnetic unit	Insulation breakdown, type fault	Failure of CVT	2	2	4	Thermovision			
	Water or other contamination	Failure of CVT	1	1	1	Thermovision			
	Corrosion of metal housing, breakdown of paint system, failure of gaskets	Damage to CVT leading to contamination	1	1	1	Inspection			
Ferroresonance circuit	Undamped ferroresonance	Functional failure of CVT	1	1	1				
Secondary	Failure leading to metering error or protection failure	Uncleared fault	1	2	2		IR during protection maintenance		Reliability STPIS Performance

5.7.13. Maintenance Program Amendments – Instrument Transformers

The Instrument Transformer maintenance was reviewed in 2016 and as a result, maintenance frequency amendments were implemented based on a consideration of the above risks. The objective of the change was for efficiency gains in the delivery of equipment maintenance. Details of the changes are included in AMI-AS0001 – Maintenance Plan Amendments July 2016 in file D2016/10692.

5.8. Static VAr Compensators (SVC) Asset Review

5.8.1. Population Review – SVCs

Transgrid has 5 Static VAr Compensators (SVCs):

- 2 at Broken Hill substation (each -25/+25 MVAr) commissioned 1986;
- 1 at Lismore (-100/+150 MVAr) commissioned 2000;
- 1 at Armidale (-120/+280 MVAr) commissioned 2000; and
- 1 at Sydney West (-100/+280 MVAr) commissioned 2004.

5.8.2. Emerging Issues, and Renewal and Maintenance Initiatives – SVCs

SVCs are specialised and expensive installations based on a complex technology but are becoming essential for the stable operation of power systems. SVCs have a nominal life of 20 years. The technology used in SVCs has been advancing and support for earlier generations may be limited.

A limiting factor on the service life of SVCs that is emerging is the life of the associated control system. The control system in an SVC is highly integrated with the thyristor valves and replacement of the control system typically entails replacement of the valves. This may also require renewal of the cooling system as it is provided to suit the service requirements of the thyristor valves. The high voltage components may be re-used in such a reconstruction.

The expected life of primary plant forming part of an SVC is expected to be the same as for similar plant in other (non-SVC) bay locations.

SVCs require water cooling of the thyristor valves to operate and the cooling system requires a continuous AC supply to run pumps. SVCs are also designed to operate and preserve the stable operation of the power system during disturbances. It is essential that the cooling system pumps remain in operation during a system disturbance or the function of the SVC will not be provided when required.

There are some examples of poor SVC reliability has been caused by slow 415V changeover or by an insufficiently robust cooling control system.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 19: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
SVCs	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Obsolescence and spare parts availability. Vendor support.	Asset manager to undertake further analysis: Continue to inspect and monitor the identified issues through defect management and defect maintenance. Further action to be taken if issues progress such that the safe and reliable operation of the substation is jeopardised and/or risks are increased.	Ongoing	Maintenance, inspection and analysis work is ongoing.
Broken Hill SVC	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Consider bird proofing due to 2020 failure.	Asset Manager to request a proposal from maintenance to restore previous bird proofing (removed during last upgrade)	To be started	TBA

5.8.3. Maintenance Program – SVCs

Because of the specialised nature of these installations, SVC maintenance is determined for each case. The maintenance requirements are summarised in an attachment to the Substation Maintenance Plan.

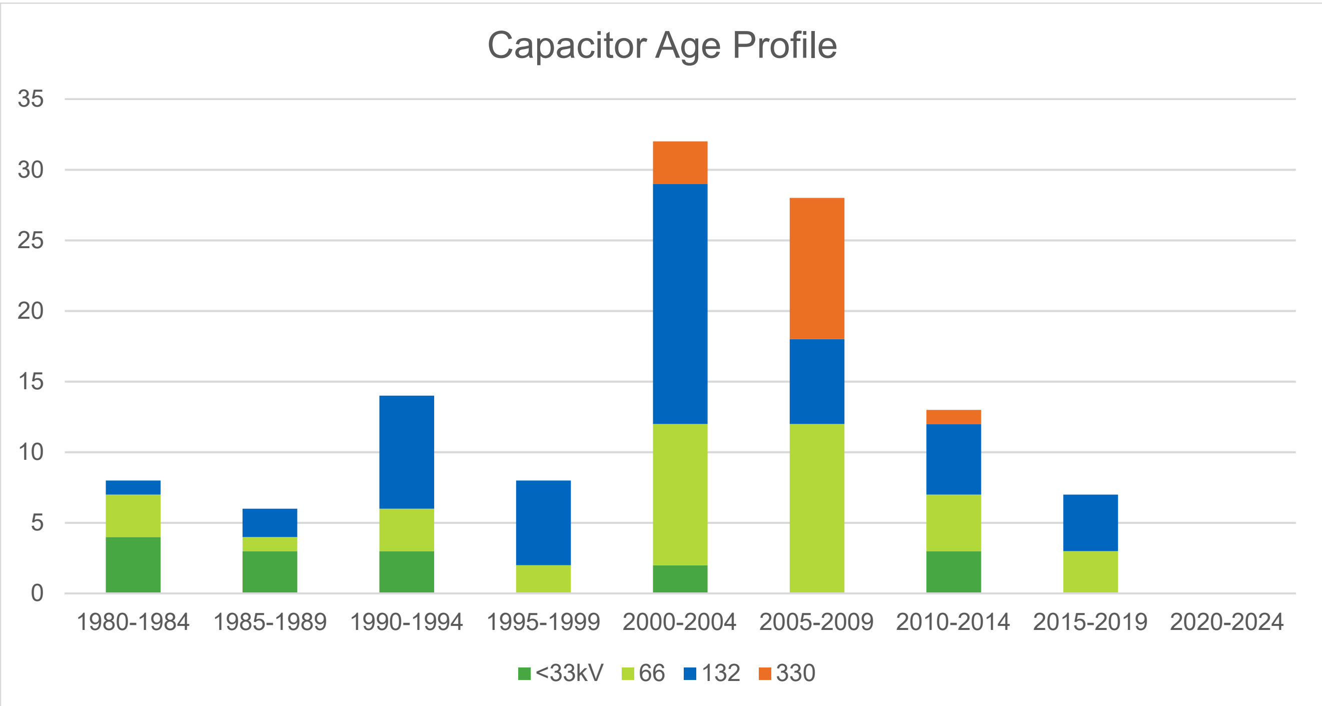
5.9. Shunt Capacitors Asset Review

5.9.1. Population Review – Capacitors

Transgrid has a total of 116 shunt capacitor banks in service within the network with an installed capacity of 6,670.2 MVAr. The banks range in voltage from 33kV to 330kV. The nominal lifespan of the capacitors ranges from 25-35 years, and approximately 10% of the capacitors in service have exceeded a 30-year life.

The majority of the capacitor units installed are of the internally fused type but some externally fused units are in service.

Figure 31: Capacitor Bank – Age profile



5.9.2. Emerging Issues, and Renewal and Maintenance Initiatives – Capacitors

Capacitor banks are reliable items of plant that have minimal maintenance requirements. Current and emerging issues that have been identified with respect to the capacitor banks are as follows:

- Increasing can failures that can indicate end of life for the bank and can lead to exhaustion of available spares.
- Where spares have been exhausted, further can failures will result in de-rating of the bank. It may be possible to obtain specially manufactured replacement cans but replacement spares have may contain a different dielectric from the rest of the bank, with a different thermal characteristic. This can lead to changes in spill current with temperature and result in bank alarms or trips.
- Cans can be affected by corrosion, leaks and broken brackets etc. across the bank.

- Switching reactors may deteriorate (normally requires recoating).
- Older banks are not tuned type and may have a higher impact on the network during switching.
- Older banks are not paved inside the HV cage and are subject to forced outages caused by weed growth and/or additional planned outages to manage weed growth.
- Outages caused by bird strike. This is addressed in new banks with the provision of insulated connections. There is a negative impact from this in that thermovision is no longer effective on bank connections.
- Hot joints may become an issue. These are detected by thermovision and addressed as defects. There have been cases of whole banks being affected by hot joints and modification of connections has been required.
- A capacitor bank earthing connection failure occurred at Kemps Creek that resulted in a sustained fault that was undetected by protection. The cause was found to be poor design where earth grid strap at ground level was used to carry full phase current at ground level. A limited number of similar cases were found and a modification is required to ensure that all load currents are carried in appropriate conductors.
- Capacitor banks can be made unavailable due to issues with neutral unbalance alarms.
- Can failures and physical deterioration are related to time in service, switching and physical exposure compounded by design susceptibilities. Older banks will hence be more affected.
- Older capacitor banks may consume available spare capacitor cans through failures and if replacement cans are no longer available, it will become impossible to ensure that the full rating of the bank is maintained for any future failures. It may be possible in such cases to accept a de-rating in the capacitor bank rating to allow ongoing operation. De-rating will allow cans to be removed from an affected bank in the case of a failure so that the bank remains balanced. Spares are also generated for future failures.
- For reactors associated with capacitor banks, there have been failures leading to fire at Tomago, Panorama and Kemps Creek in the previous 18 months. There are indications of the 'treeing' at the Bayswater reactors. This issue is common with the air core reactors in general.
- 5 Capacitor Banks have been selected for renewal during the 2023/24 to 2027/28 period.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 20: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Shunt Capacitor Banks	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Leaking insulator fluid. Obsolescence and a lack of spares.	Asset manager to undertake further analysis: Continue to inspect and monitor the identified issues through defect management and defect maintenance. Further action to be taken if issues progress such that the safe and reliable operation of the substation is jeopardised and/or risks are increased.	Ongoing	Maintenance, inspection and analysis work is ongoing.
Shunt Capacitor Banks	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Capacitor Bank associated circuit breakers Issue with neutral unbalance alarms Issue with automatic voltage control		Ongoing	Maintenance, inspection and analysis work is ongoing.
Capacitor Banks	• Manage network safety risk	Neutral unbalance alarms causing unavailability of capacitor banks	Operational/Renewal Initiative: Review of capacitor bank defects to trigger further investigation and condition assessment. Outcome of condition assessment will determine maintenance or renewal initiative.	Ongoing	Maintenance, inspection and analysis work is ongoing.

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Shunt Capacitor Banks	• Maintain network reliability	Poor neutral earthing bar design (330kV Capacitor Banks)	Operational initiative Modify the affected capacitor banks to remove the issue and improve protection system design where possible.	Ongoing	IWR0167
Capacitor bank air cored reactors	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Failures of the air cored reactors at Panorama and Kemps Creek in 2019 may indicate an emerging issue.	Confirm root cause of failure and initiate strategy and actions as required. Initiate replacement of failed reactors through prescribe investment process.	In progress.	Replacement reactor need N2126.
Capacitor Bank	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Failure of capacitor cans, associated air core reactors, and NUCTS	Initiate asset renewal on key capacitor banks.	RP3	N2473

5.9.3. Maintenance Program – Capacitors

Capacitor banks are static items of plan with minimal maintenance requirements. Maintenance consists of inspection to identify physical defects and thermovision where possible to identify hot joints. Defect maintenance may result from unbalance alarms or trips.

5.10. Surge Arrestors Switches Asset Review

5.10.1. Population Review – Surge Arrestors

Surge arrestors are used to protect expensive items of plant (such as transformers and reactors) from failure due to transient voltage surges or lightning strikes. There are over 2,409 surge arrestors installed across Transgrid's system.

The most significant issue concerning surge arrestors has been the potential for explosive failure of older Silicon Carbide types that contain spark gaps provided to limit the 50Hz current drain during normal operating conditions, with water ingress often resulting in explosive failure of the surge arrestor. Elimination of gapped surge arrestors is a replacement program that has been operating over a number of years and is nearing completion.

Newer Zinc Oxide types do not contain spark gaps. There is no suitable method presently available for the routine monitoring of zinc oxide surge arrestor condition.

5.10.2. Emerging Issues, and Renewal and Maintenance Initiatives – Surge Arrestors

The only emerging issue associated with surge arrestors is the removal of gapped surge arrestors which was outlined above.

Table 21: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Surge Arrestors	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Failure at Eraring 500kV substation	Determine cause and next steps.	In progress	

5.10.3. Maintenance Program – Surge Arresters

Surge arresters are essentially maintenance free due to the lack of moving parts and their solid insulation system. Cleaning of insulators is completed during the associated bay maintenance.

Substation inspections will identify any issues which will be rectified on a defect basis.

5.11. Disconnectors and Earth Switches Asset Review

5.11.1. Population Review – Disconnectors and Earth Switches

Transgrid manages a total disconnector and earth switches population of 5,264 units ranging in voltage from 11kV to 500kV. The disconnectors and earth switches population is comprised of:

- 3,064 Disconnectors (DISC) – this account for approximately 57.2% of the total population.
- 2,200 Earth Switches (ESW) – this account for approximately 41.8% of the total population.

The disconnectors and earth switches age profile is shown in Figure 32 and Figure 33. It shows that approximately 20% of the units were commissioned before 1980, and have thus exceeded their nominal lifespan of 40 years. The oldest units were manufactured in 1957. The disconnectors and earth switches have an average age of approximately 24.3 years.

Earth switches are usually integrated with disconnectors, being procured at the same time from the same manufacturer. Replacement of the disconnector routinely requires the replacement of the associated earth switch where the disconnector and earth switch are a single integrated structure.

Figure 32: Disconnectors and Earth Switches – Age profile

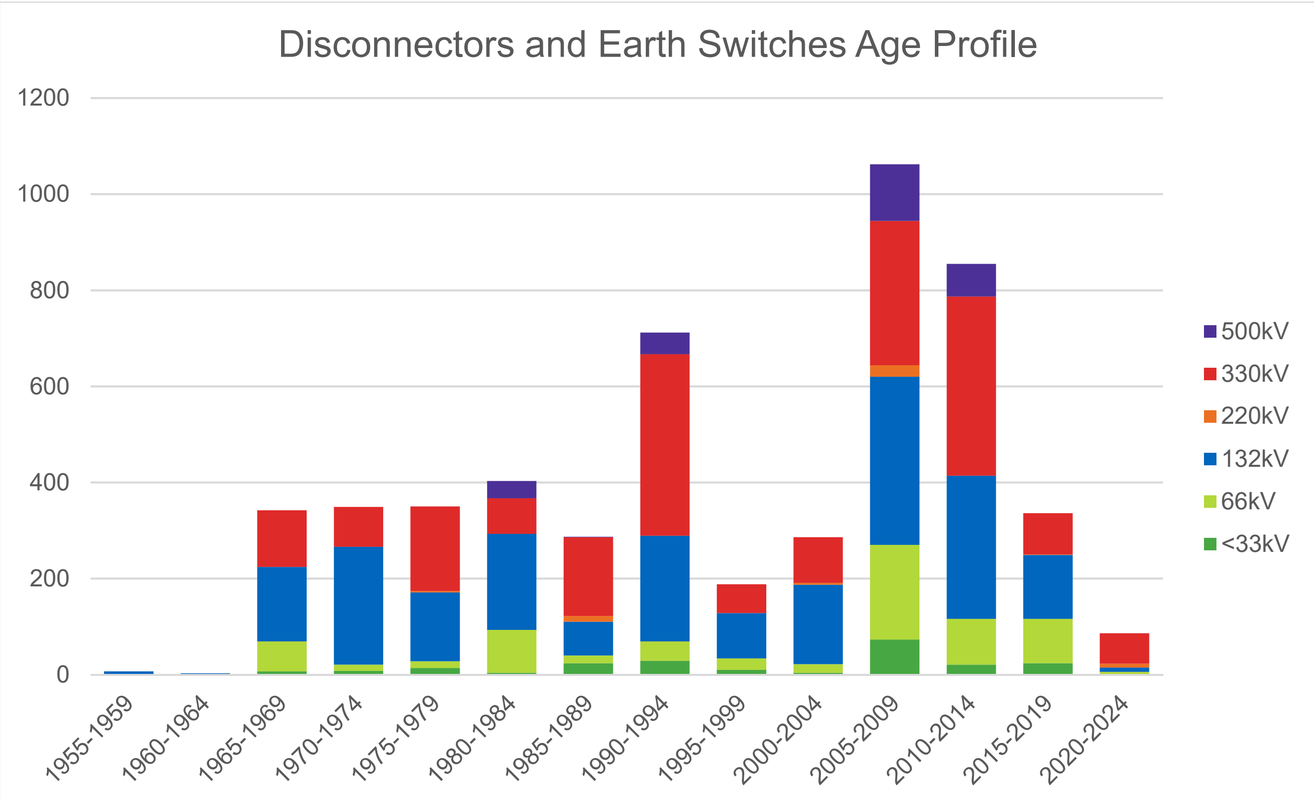
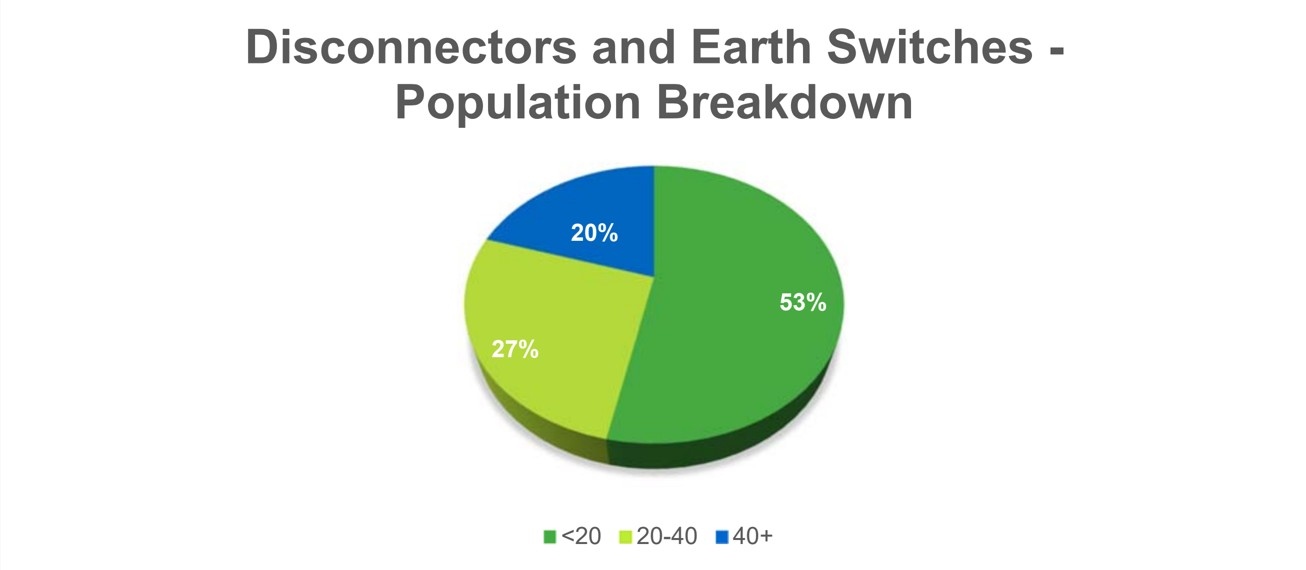


Figure 33: Disconnectors and Earth Switches – population breakdown



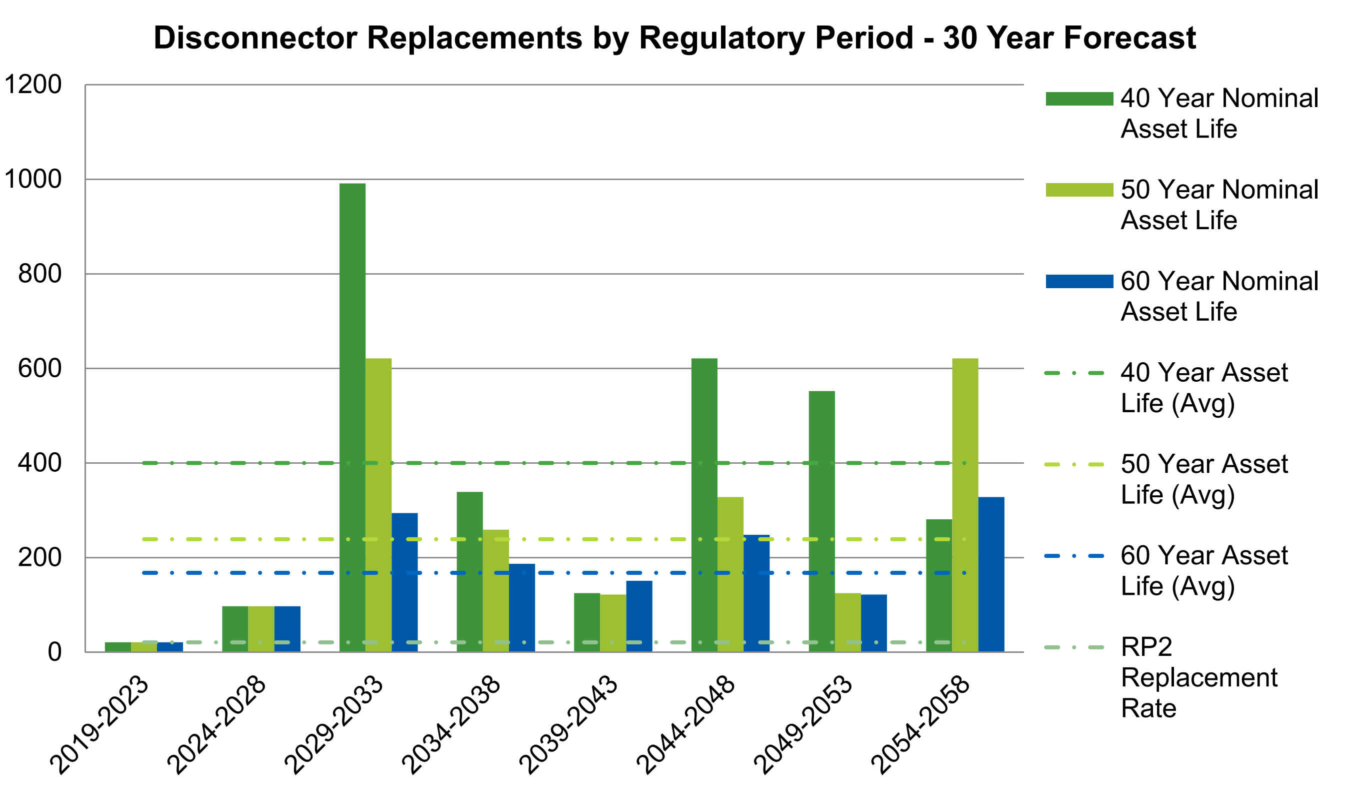
There have been 21 disconnectors identified for replacement in the 2018/19 to 2022/23 period which include a total of 17 associated earth switches. This represents 0.4% of the disconnector and 0.3% of the earth switch population. During the 2023/24-2027/28 period, 97 disconnectors and earth switches have been identified for replacement, and 11 are to be refurbished, which represents 2.3% of total population.

Long term forecasting of disconnector replacements based on asset age exceeding a nominal lifespan of 40, 50 and 60 years is presented below. In this forecasting, the 97 disconnectors that are proposed to be replaced in regulatory period 2023/24-2027/28 are modelled to be replaced in 2026 and the 11 disconnectors that are proposed for refurbishment are modelled to be replaced in 2036. Even with that proposal, it results in replacement rates much higher than that of planned in RP2 and RP3. The forecast replacement rates per 5 year regulatory period over the next 30 years are shown below in

Figure 34

Forecasts based on extended asset lives are also shown to demonstrate that even using optimistic asset life expectancy as high as 60 years supports a higher replacement rate than that proposed in RP3. This modelling demonstrates the clear need to increase replacement rates, above those in the current period, into the future.

Figure 34: Disconnector Replacements by Regulatory Period



5.11.2. Emerging Issues, and Renewal and Maintenance Initiatives – Disconnectors and Earth Switches

The following current and emerging issues have arisen with regard to disconnectors and earth switches. Use of disconnectors in an air insulated switchyard with associated equipment having much lower maintenance requirements is a significant problem. Disconnectors are provided essentially to allow safe access to other high voltage equipment.

The reliability of disconnectors/earth-switch is becoming an issue, which is due to two main causes:

- Newer types of disconnectors have not been performing well, with concerns regarding the robustness of their design. This is being addressed through attention to specifications used and inclusion of additional requirements related to robustness.
- There have been cases of mechanical failures and failures of contacts on older disconnectors/earth-switches and deterioration is occurring due to their length of service and exposure to weather. Refurbishment or replacement may become necessary.
- Disconnectors/earth switches being isolation equipment, the maintenance and repair on them require outage of either bay or busbar, which is often challenging to schedule work due to limitations of outage window available on some of the locations in the network.

The most common of these two issues is the second which is due to the ageing of the disconnectors, which leads to the following:

- Difficulty or inability in operation due to corrosion or poor contact alignment

- Failure of mechanical drive components including turnbuckles, bearings and motors.
- Degradation of contacts leading to sticking or hot joints.
- Lack of manufacturer support and the inability to procure required parts for maintenance activities.
- Oil leakage from viscous couplings
- Failure of indicating lamps

The original design of some older disconnectors can also include the unsafe location of the isolating fuses within the control box which are in the proximity of other electrical terminals.

Presently 1064 (20%) disconnectors and earth switched exceed the nominal asset life, with a further 77 units forecast to exceed the nominal asset life by the end of RP2. Planned replacements rates are unsustainable in the long term to address the ageing of the asset class and subsequent increasing probability of failure.

A 30 year forecast of replacements, based on the nominal asset life of 40 years suggests replacement rates in the order 400 disconnectors per 5 year regulatory period is required. On this basis it is expected that disconnector and earth switch replacement rates will increase in the coming years and regulatory periods.

Asset data improvement activities were initiated through a disconnector survey. The survey was initiated to facilitate accurate defect/maintenance work order recording for disconnectors and earth switches. Transgrid's asset management system is designed in a way that defects are recorded against a bay, which makes it difficult to identify the defect raised against particular disconnector especially for busbar disconnectors. The survey was completed in FY17 to add operating numbers to each asset record when raising work orders. However, there were a number of discrepancies identified in the survey, which have required the review of survey results for sites which did not have completion of survey data. With successful engagement with Delivery, desktop review work is now well underway for expected completion in FY2021. Upon this review, resurvey of only a few remaining sites will be required.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 22: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Disconnectors & Earth Switches	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Disconnector condition issues are developing arising from age related deterioration. Difficulty or inability in operation due to corrosion or poor contact alignment Failure of mechanical drive components including turnbuckles, bearings and motors. Degradation of contacts leading to sticking or hot joints. Lack of manufacturer support and the inability to procure required parts for maintenance activities.	Renewal initiative: Replace disconnectors based on economic evaluations to address associated risks.	RP2 21 units replaced	Need No: 1357
				RP3 (2023 – 2028) – Commencing 2023	Need No: N2349
Disconnectors & Earth Switches	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value		Refurbishment investigation	Completed and targeted disconnectors are evaluated for RP3 proposal.	IWR-N2314
By-pass disconnectors	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Wagga incident report finding and follow-up action to check condition of pallet switches for by-pass disconnectors	Condition assessment	Partial completion with desktop checks of operation of number of disconnectors.	IWR-N2253
HAPAM make disconnectors	• Manage network safety risk • Maintain network reliability	HAPAM make disconnectors supplied prior to 2010 have defect in mechanism design causing operational issues.	Trial of Installation of	Trial work impacted due to COVID and didn't result as	

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
and earth switches	• Manage assets efficiently to deliver security holder and consumer value	Post 2010 design have double bearing mounting arrangement and doesn't have same issues in operation. Supplier has proposed use of conversion kit to resolve operational issues with HAPAM build prior to 2010.	conversion kit at SYW.	expected. Further investigation of graphite contacts is underway.	
Disconnectors & Earth Switches	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Most of disconnectors at Kangaroo valley station are Stanger make and past their nominal life. They are all having difficulty in operation and as a result switching and operation at this site requires outage of the entire substation which impacts on customer generation and network availability.	Trial repairs and initiate some replacements	To be initiated in RP2	PCR-1357 Rev3

5.11.3. Maintenance Program – Disconnectors and Earth Switches

Maintenance for disconnectors and earth switches is largely defect based and depends on review and rectification of defects raised during substation inspection activities. These inspections include:

- Thermovision inspection
- Substation inspection

In addition to inspections, some routine maintenance is implemented as follows:

- Operational checks
- Checking of rod gap spacing
- Minor servicing if efficient to complete during other works
- Servicing of Taplin and ALM types to implement known solutions to identified issues.

Disconnector and Earth Switch maintenance was reviewed in 2016 and changes in frequency were made based on a consideration of the associated risks. The objective of the change is for efficiency gains in the delivery of equipment maintenance through alignment with associated bay equipment maintenance intervals.

The changes in maintenance affecting disconnectors and earth switches include:

- An extension of the time between maintenances

The interval for maintenance of disconnectors and earth switches was formerly 4 years and this has been extended to next bay maintenance years

Details of the changes are included in AMI-AS0001 – Maintenance Plan Amendments July 2016 in file D2016/10692.

5.12. OLCM Equipment Asset Review

5.12.1. Population Review - OLCM

Online condition monitoring in Transgrid is continuous, in-service monitoring that returns information about key equipment parameters or indicators, generally through the use of specialised sensors or devices. Transgrid implemented Online Condition Monitoring in response to a 2002 Transformer Failure Investigation, after identifying the following potential benefits in the use of this type of equipment:

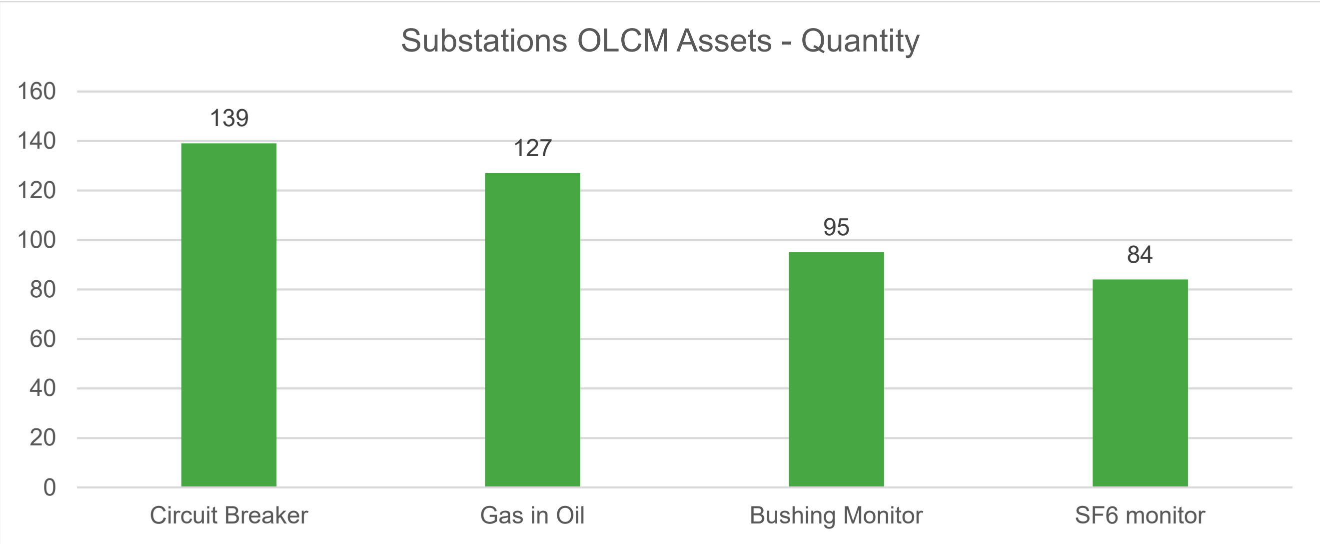
- Avoidance of failure through more intensive monitoring of key condition characteristics.
- A reduction in off line maintenance requirements where on line monitoring provides sufficient information and confidence
- A reduction in costs (and WHS benefits) where predictive loss of insulating gas functionality can be employed, replacing defect call-outs with scheduled top-up activities
- Potential to increase the time to replacement for equipment that would otherwise need to be removed to ensure no failure in service.

- Safety benefits of reducing exposure through avoided onsite maintenance activities for sites where electrostatic field strengths are known to have significant induction hazards; e.g. 500kV Circuit Breakers mechanism cabinets.

Transgrid have chosen devices that monitor a range of quantities on different equipment, including:

- Transformers:
  - Hydrogen (or volatile dissolved gases) in oil.
  - Moisture in oil
  - Bushing Tan δ and Capacitance
- Circuit breakers:
  - Timing and travel (during operation)
  - Operating mechanism current consumption
  - Insulating gas density
- GIS:
  - Insulating gas density

Figure 35: OLCM population profile



The condition monitoring system is integrated into the Transgrid control system, with this IT network managed by the Secondary Systems Asset Manager. In order to establish clear responsibilities, Substation Assets do not include any site servers or network servers in the OLCM device population.

The OLCM system has been in place for the last 8 years with two significant successes where online bushing monitoring has prevented the failure of the associated 330kV 375MVA transformers.

5.12.2. Emerging Issues, and Renewal and Maintenance Initiatives - OLCM

Some component replacements have already been necessary due to end of life conditions. Other issues include:

- Reliability of the monitoring device itself. There have been a number of false alarms from condition monitoring equipment leading to unnecessary outages and offline testing.
- The life of condition monitoring sensors is thought to be 10-15 years. An example of this that is now being encountered is the failure of hydrogen in oil monitors as the electrochemical sensor ages.
- Increasing number of plant types with known abnormalities which would benefit from OLCM monitoring
- Increasing installed volume of SF6 gas (GIS in particular)
- The capital cost of additional installations needs to be offset against the possible gains.
- Newer protection relays can have the capacity to perform OLCM. Where new protection relays are being installed, this capacity will be investigated and integrated as appropriate.

The current and emerging issues and renewal and maintenance initiatives are summarised in the table below.

Table 23: Emerging Issues, and Renewal and Maintenance Initiatives

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
Online Condition Monitoring (OLCM)	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Reliability of OLCM devices and sensors. Modifications to data requirements to meet increasing demands from users Bushing types with known defects Aging Transformer/Reactor units with unacceptable moisture/gas content Increasing volume of SF6	Continue to inspect and monitor the identified issues through defect management and defect maintenance. Further action to be taken if issues progress such that the safe and reliable operation of the substation is jeopardised and/or risks are increased Bushing monitoring devices have proven their effectiveness on OIP bushings. All OIP bushings will have OLCM installed during RP3.	Ongoing	Maintenance plan Need N2290
Circuit Breakers - OLCM Devices	• Manage network safety risk • Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	Deployment of OLCM devices onto low or non-critical circuit breakers Population of high criticality and remote circuit breakers have no online condition monitoring installed.	Consider relocation of OLCM devices from low criticality CBs to nominated CBs based on operating duty, location and criticality.	Under consideration	Need: 1681
All major equipment OLCM	• Manage network safety risk • Maintain network reliability	Newer protection relays can have advanced OLCM and diagnostic capability, for little additional cost. Where secondary systems	Review and evaluate the use of protection relays for OLCM functionality and embed into design processes.	Not yet commenced	

Assets	Asset Management Objective	Emerging Issues	Strategic Initiative	Progress (completion and expenditure)	Reference Documents
	• Manage assets efficiently to deliver security holder and consumer value	replacements are being undertaken, consideration of this advanced capability will be made.			
OLCM devices	• Maintain network reliability • Manage assets efficiently to deliver security holder and consumer value	The existing population of OLCM does not have complete asset data and renewal and maintenance strategies require refreshing. False alarms are received from OLCM leading to outages.	Undertake a review of asset population, update and document renewal and maintenance strategies. Determine cause of false alarms and appropriate strategies.	Not yet commenced	

5.12.3. Maintenance Program – OLCM

The likely benefits occurring from on-line condition monitoring and in particular, the potential for improved reliability and availability of Substation Plant are considered when identifying appropriate maintenance activities for Substation plant. Where reliable on-line systems are in place, certain periodic diagnostic or invasive maintenance requirements may become redundant with the approval of the Asset Manager. Minimum prerequisites for such amendments are:

- Installation of reliable sensors
- Adequate communication systems to facilitate the collection of condition monitoring data,
- Robust systems for the specification and implementation of settings and alert thresholds, and
- Effective asset management processes and resources to monitor, assess and action the on-line condition monitoring data

In the main, Routine Maintenance activities are designed to identify abnormalities in plant and equipment by comparing measurement data and inspection information with limits and requirements described in the Substation Condition Monitoring Manual – GM AS S1 008. Where an abnormality exceeds a predetermined allowable value, a range of escalated actions are described, designed to address each abnormality.

Condition monitoring devices are capable of collecting a range of similar measurement data and information online, resulting in reductions in maintenance costs and some benefits in safety, particularly on 500kV circuit breakers. Where devices are installed on Transformers and Reactors, benefits can be derived where the devices are monitoring existing abnormal conditions or defects.

Installation of Condition Monitoring however, must be consistent with the following principles:

- Maintenance is to be minimised consistent with reliable performance
- Maintenance costs are to be minimised consistent with corporate objectives of safety, reliability, availability and risk management.
- New devices are to be of a proven safe, reliable and low maintenance design fitted with sensors with known long term operating life

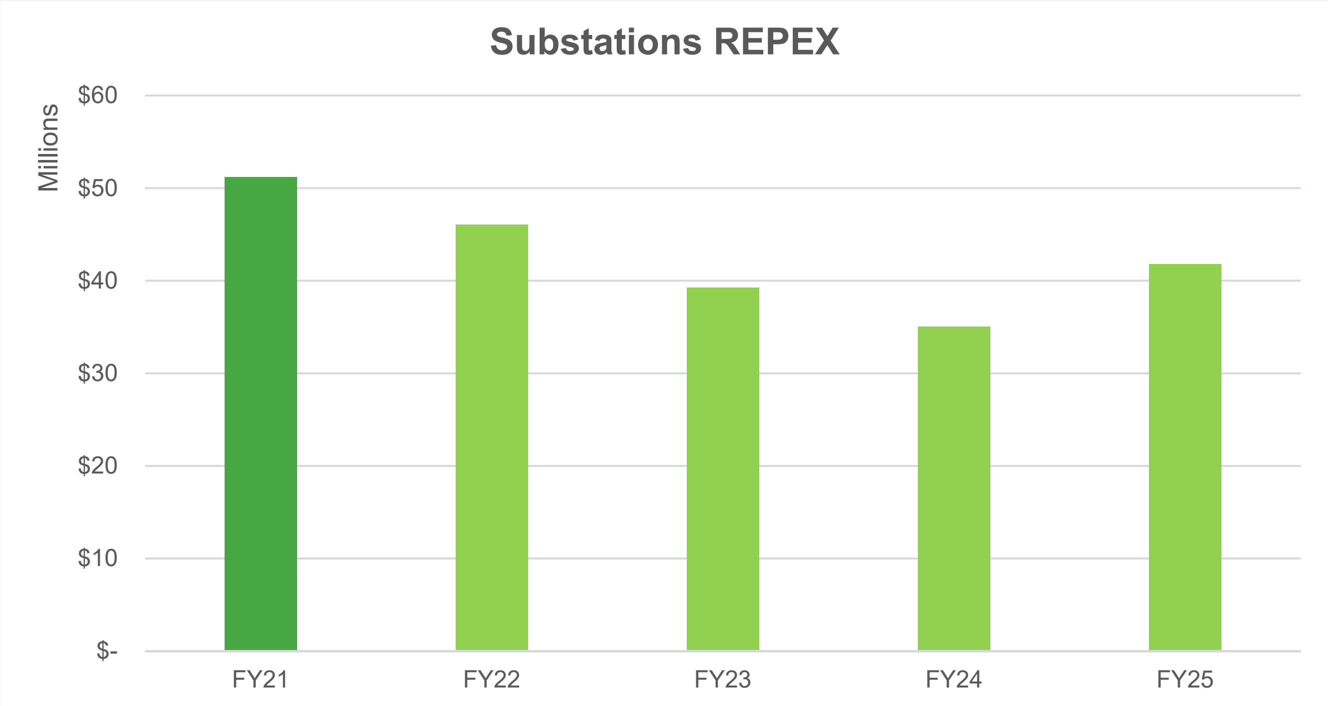
Where known issues apply to a Condition Monitoring device, specific maintenance initiatives will be implemented whilst continuing to ensure that any maintenance initiative designed to address specific concerns adhere to the principles outlined above.

6. CAPEX Forecasts

6.1.1. 5 year CAPEX Profile

The future 4 years capital requirements from the renewal initiatives detailed section 5 are shown below, FY21 values are actual spend. Augmentation expenditure is excluded from this forecast.

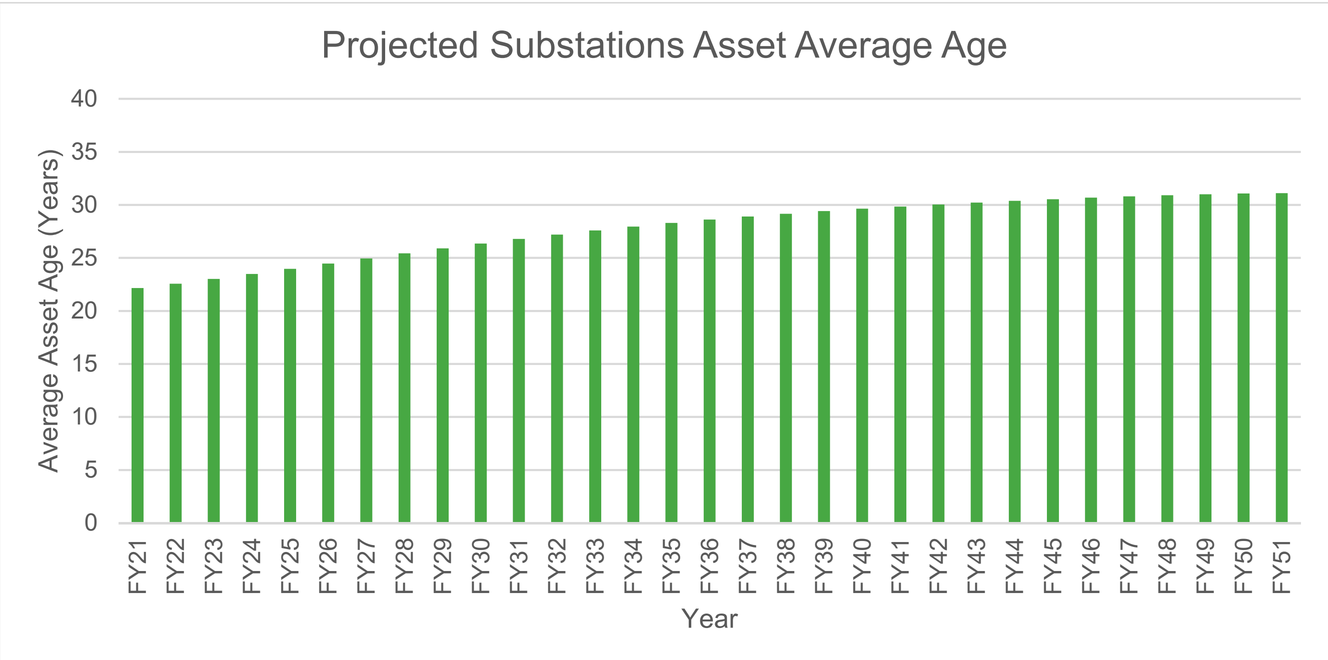
Figure 36: CAPEX Forecast for Substations



6.1.2. Anticipated Changes to the Asset Base

It is anticipated that the average age of substation HV assets will increase at a moderate rate over the next few decades. This is due to continuing investment and advancement in technologies that will maintain the reliability of the aged asset in the future. However it is expected that increased replacement expenditure will be required to manage the risk associated with the expected increase in asset age.

Figure 37: Projected Substations Asset Classes Average Age



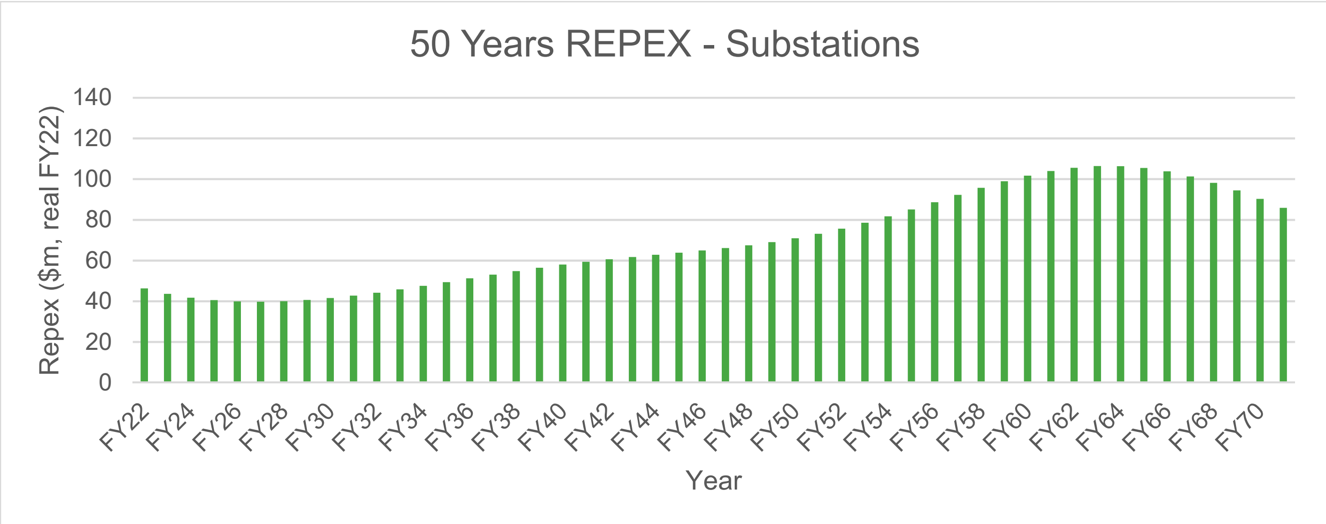
6.1.3. Long Term - REPEX Investment Framework

The 50 Year REPEX model is used by Transgrid to create a 50 year forecast, which is based on expected asset lives, standard deviations and unit costs. The assumptions within the model are based on industry standard information. This forecast includes REPEX volumes, costs and consequential average life profiles but no other consequential inputs/outputs (such as reliability and asset health). It also does not include augmentation expenditure. An overview of the REPEX investment levels for the next 50 years is shown in Figure 38 below. The model indicates that there will be an increase in REPEX in the next 40 years and the REPEX level will drop slightly beyond that.

Shorter term forecasting related to the next 5-year revenue determination period is performed using a bottom up approach through an asset analytics tool using a number of financial and non-financial (risk) inputs.

The differences between the 50 year projection and the current 5 year period, which is lower, is to achieve the objective of managing assets efficiently and delivering security holder and consumer value through reduced long term capital expenditure.

Figure 38: Projected Substations Asset Classes Replacement Expenditure



7. OPEX Forecasts

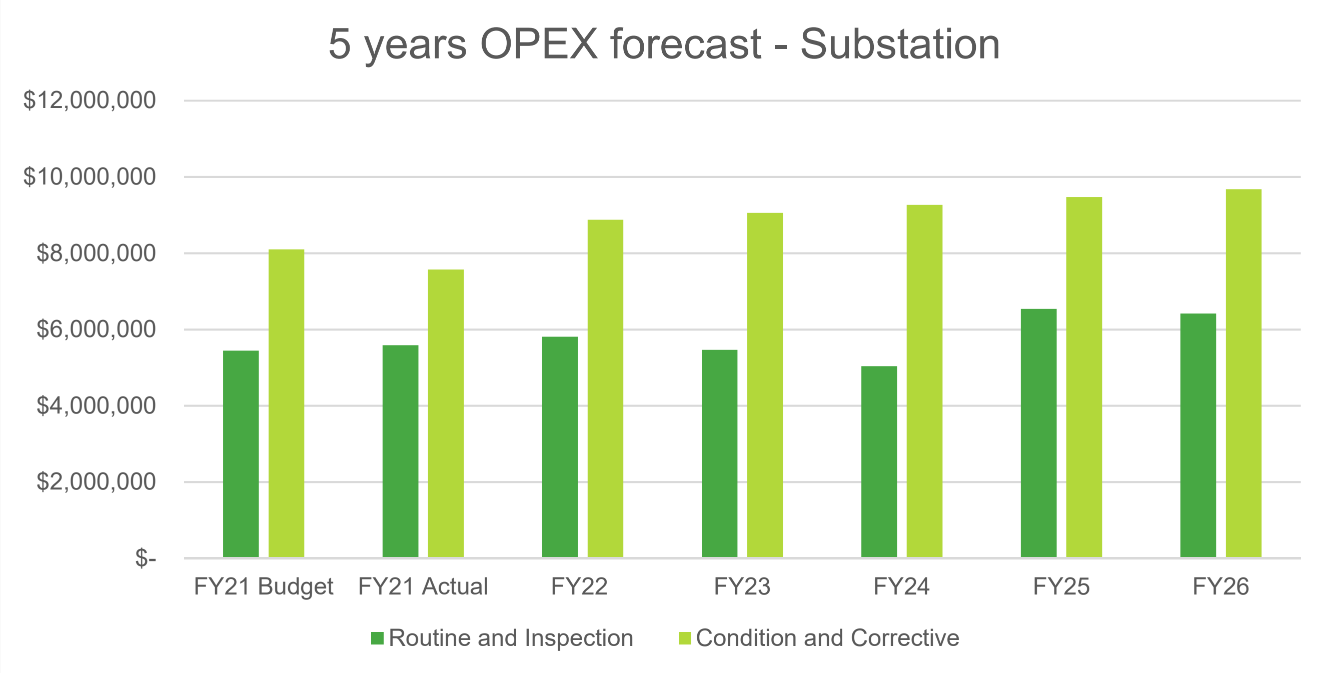
7.1.1. Discussion of significant changes to Maintenance Plan

There are no significant changes to the Maintenance Plan approved in January 2019 which would impact on prescribed maintenance forecasts. The forecasts in this section assume no augmentation. AEMO's Integrated System Plan indicates that there would likely be an increase in new substations and reactive plants in NSW within the next five years.

7.1.2. 5 year OPEX Profile

The five year OPEX profile is shown in Figure 39 below, FY2021 values are actuals.

Figure 39: Substations Asset Classes Operational Expenditure 5 year forecast



8. Implementing the Strategies

To implement the strategic renewal and maintenance initiatives stemming from this document, actions are to be established via the:

- Maintenance Plan – Substation Assets: The maintenance plan outlines the routine maintenance tasks and frequencies for each asset type.
- Capital Works Program: The capital works program outlines the approved asset renewal and disposal projects.

The Substation Asset Manager is responsible for preparation of the maintenance plans and referring the renewal and disposal initiative to the network investment process. Field Services is responsible for delivering the maintenance plans as per the Service Level Agreements, and Portfolio Management group/Project Services are responsible for delivering the renewal and disposal initiatives detailed in the approved capital works program.

9. Definitions

Term	Definition
Asset Management Objectives	• Specific and measurable outcomes required of the assets in order to achieve the Corporate Plan and objectives; and/or • Specific and measurable level of performance required of the assets; and/or • Specific and measurable level of the health or condition required of the assets; and/or • Specific and measurable outcomes or achievement required of the asset management system.

Term	Definition
Asset Management Plans	Documents specifying activities, resources, responsibilities and timescales for implementing the asset management strategy and delivering the asset management objectives.
AUGEX	Augmentation Capital Expenditure
Bushfire Danger Period	The Bushfire Danger Period is defined in the D2015/09823 Bushfire Risk Management Plan. Works Delivery shall be responsible for monitoring and communicating the commencement of the bushfire danger period.
Emerging Issues	Newly identified issues with an asset that pose a risk to the achievement of the corporate and asset management objectives.
Fault Outage	AER defined term - Fault outages are unplanned outages (without notice) on the prescribed network from all causes including emergency events and extreme events.
Forced Outage	AER defined term - Forced outages are outages on the prescribed network where less than 24 hours notification was given to affected customers and/or AEMO (except where AEMO reschedules the outage after notification has been provided). Forced outages exclude fault outages.
Health Index	An approach based on an assessment of asset condition using available condition data is used to estimate failure risk; demonstrate any requirement for action; and to rank the priority of work that results. This approach is further described in in D2016/02430 – Circuit Breaker Health Index Method Description.
Key Hazardous Events	They events of most concern associated with the assets that prevent the achievement of the corporate and asset management objectives.
RP1	Regulatory Period 2014/15 – 2017/18
RP2	Regulatory Period 2018/19 – 2022/23
RP3	Regulatory Period 2023/24 – 2027/28
REPEX	Replacement Capital Expenditure
NAS	Network Asset Strategy
RMS	Renewal and Maintenance Strategy

10. Document Management

10.1. Monitoring and review

Implementation of the Substation Renewal and Maintenance Strategy is monitored and reviewed by the Substation Asset Manager, Manager/Asset Management and Executive Asset Strategy Committee annually.

10.2. Roles and Responsibilities to Develop this Asset Strategy

The roles and responsibilities of those responsible for the development of this asset strategy are as follows:

- The Head of Asset Management is responsible for the approval of this strategy.

- Substations Asset Manager is responsible for the development and regular review of this strategy. The document will be reviewed biannually and as significant changes to investment needs become apparent.

10.3. References

Asset Management Strategy and Objectives

Asset Management System Description

Maintenance Plan – Substation Assets

Substations Condition Monitoring Manual

Prescribed Capital Investment Process

Appendix A - Substation Asset Breakdown

The following gives a structured breakdown of Substation related assets and where in the Renewal and Maintenance Strategy documents they can be found:

Item	Asset Strategy Coverage
Site	
Surrounds	
Oil containment dams	5.2 Site/Infrastructure
Fire buffer	Network Property RMS
Grassed areas	Network Property RMS
Drainage outlets	5.2 Site/Infrastructure
Transmission line structures	Transmission Line RMS
Easements	Transmission Line RMS
Boundary fences	Network Property RMS
Roads	Network Property RMS
Switchyard	
Earthgrid	5.2 Site/Infrastructure
Main grid	5.2 Site/Infrastructure
Earth connections	5.2 Site/Infrastructure
Isolations (from outside sources)	5.2 Site/Infrastructure
Civil	
Bench	
Oil containment including compounds and bunds etc.	5.2 Site/Infrastructure
Normal drainage	5.2 Site/Infrastructure
Covering(gravel/grass)	5.2 Site/Infrastructure
Roads and access (internal)	Network Property RMS
Cable Trenches	5.2 Site/Infrastructure
Footings	5.2 Site/Infrastructure
Steel (includes fitting and holding down bolts etc.)	5.2 Site/Infrastructure
Equipment structures	5.2 Site/Infrastructure
Main structures	5.2 Site/Infrastructure
Kiosks and boxes	Sec Sys Site Installation RMS
AC and DC distribution (switchyard boxes)	Sec Sys Site Installation RMS
BMK	Sec Sys Site Installation RMS
VT and CT marshalling boxes	Sec Sys Site Installation RMS
BBP summation	Sec Sys Site Installation RMS

Item	Asset Strategy Coverage
Ancillary Equipment	
Cabling – control - low voltage	Sec Sys Site Installation RMS
Security	
Access Systems	Network Property RMS
Keys and locks	Network Property RMS
Fences and gates	Network Property RMS
Alarm systems	Network Property RMS
Camera systems	Network Property RMS
Fire	Network Property RMS
Fire pumps	Network Property RMS
Fire tanks	Network Property RMS
Hydrant systems	Network Property RMS
Fire alarm system	Network Property RMS
VESDA	Network Property RMS
Sprinkler systems (compressors, pipes, etc)	Network Property RMS
Fire kiosks	Network Property RMS
Gas systems	Network Property RMS
Deluge system	Network Property RMS
AC Supplies	Sec Sys Site Installation RMS
Switchboards	Sec Sys Site Installation RMS
Alternators	5.2 Site/Infrastructure
Switchyard cabling	Sec Sys Site Installation RMS
Outlets	Sec Sys Site Installation RMS
Local boxes	Sec Sys Site Installation RMS
DC supplies	Sec Sys Site Installation RMS
Chargers	Sec Sys Site Installation RMS
Batteries	Sec Sys Site Installation RMS
Distribution boards	Sec Sys Site Installation RMS
GIS	
Building related	
Cranes	Network Property RMS
Gas warning systems	5.2 Site/Infrastructure
Gas collection (Haymarket only)	5.2 Site/Infrastructure
Mechanical ventilation/chillers etc	5.2 Site/Infrastructure
Lifts	Network Property RMS

Item	Asset Strategy Coverage
Building management systems	Network Property RMS
Fire systems	Network Property RMS
Air conditioning	Network Property RMS
Primary Plant	
Circuit breakers	5.5 Circuit Breaker
Current Transformers	5.7 Instrument Transformer
Hairpin	5.7 Instrument Transformer
Live head gas/oil	5.7 Instrument Transformer
Torroids (e.g. dead tank CBs)	5.7 Instrument Transformer
Neutral unbalance CTs	5.7 Instrument Transformer
Other types	5.7 Instrument Transformer
Voltage Transformers	5.7 Instrument Transformer
MVT gas/oil/epoxy	5.7 Instrument Transformer
CVT	5.7 Instrument Transformer
Disconnectors	5.11 Disconnector/Earth Switch
Earth Switches	5.11 Disconnector/Earth Switch
Power Transformers	5.3 Transformers
Windings	5.3 Transformers
Tapchanger	5.3 Transformers
Bushings	5.3 Transformers
Fans and pumps	5.3 Transformers
Tank	5.3 Transformers
Radiator	5.3 Transformers
Conservator	5.3 Transformers
Valves	5.3 Transformers
Aux transformers	5.3 Transformers
Reactive plant	5.4 Reactors
Reactors	5.4 Reactors
Oil filled	5.4 Reactors
Windings	5.4 Reactors
Bushings	5.4 Reactors
Fans and pumps	5.4 Reactors
Tank	5.4 Reactors

Item	Asset Strategy Coverage
Radiators	5.4 Reactors
Conservator	5.4 Reactors
Valves	5.4 Reactors
Air core	5.4 Reactors
Neutral Earthing	5.4 Reactors
Capacitors	5.9 Capacitors
SVCs	5.8 SVC
GIS Equipment	
Circuit Breakers	5.6 GIS
Three position switch	5.6 GIS
VT	5.6 GIS
CT	5.6 GIS
Insulating earth switch	5.6 GIS
Gas compartment	5.6 GIS
Surge arrestors	5.6 GIS
Duct	5.6 GIS
Conductors	5.6 GIS
Barriers	5.6 GIS
Burst disks	5.6 GIS
Gas monitoring sensors	5.6 GIS
Gas Insulated Transformers/Reactors	
Tanks	5.3 Transformers / 5.4 Reactors
Monitoring	5.3 Transformers / 5.4 Reactors
Cooling system	5.3 Transformers / 5.4 Reactors
Blowers	5.3 Transformers / 5.4 Reactors
Tap changers	5.3 Transformers / 5.4 Reactors
Others	5.3 Transformers / 5.4 Reactors
Line traps	5.2 Site/Infrastructure
Surge arrestors	5.2 Site/Infrastructure
Cables	

Item	Asset Strategy Coverage
<66kV	5.2 Site/Infrastructure
>=66 kV	Underground Cables RMS
Fault throwing switch	5.11 Disconnector/Earth Switch
Earthing transformer	5.7 Instrument Transformer
HV Connections and fittings	5.2 Site/Infrastructure
PLC coupling equipment	Telecommunications RMS
Other	5.2 Site/Infrastructure
Secondary Systems	
Tunnel boards or equivalent	Sec Sys Site Installation RMS
Control and alarms	Sec Sys Site Installation RMS
Protection	Sec Sys Site Installation RMS
Metering	Sec Sys Site Installation RMS
OLCM infrastructure	Sec Sys Site Installation RMS
Communications	
Towers	Telecommunications RMS
Antennae	Telecommunications RMS
Waveguides	Telecommunications RMS
Terminal equipment	Telecommunications RMS
Optic fibre marshalling boxes	Telecommunications RMS
Fibre	Telecommunications RMS
OLCM	
Devices	5.12 OLCM
Infrastructure	Automation Systems RMS
Buildings associated with Switchyards:	
Building standard control building and internal switchyard buildings and sheds	
Building structure and roof permanent fixtures	Network Property RMS
Control Room	Network Property RMS
Amenities	Network Property RMS
Workshop	Network Property RMS
Cranes	Network Property RMS
Storage including switchyard storage areas	Network Property RMS

Item	Asset Strategy Coverage
Air conditioning	Network Property RMS
Plumbing	Network Property RMS
Telstra lines	Telecommunications RMS
Battery Room	Network Property RMS
Lighting normal and emergency – switchyard and building	Network Property RMS
Car park/paved areas	Network Property RMS