Independent Verifier's review of Transpower's RCP3 expenditure proposal

Supplementary information in support of the Independent Verification Report

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Synergies Economic Consulting Pty Ltd
www.synergies.com.au

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Contents

Figures and Tables

A Overview

The purpose of this report is to present additional key supporting information, primarily provided by Transpower, which was used in our Independent Verification Report of Transpower's forecast expenditure for its RCP3 Proposal.

The three subject matter areas covered in this supplementary report are as follows:

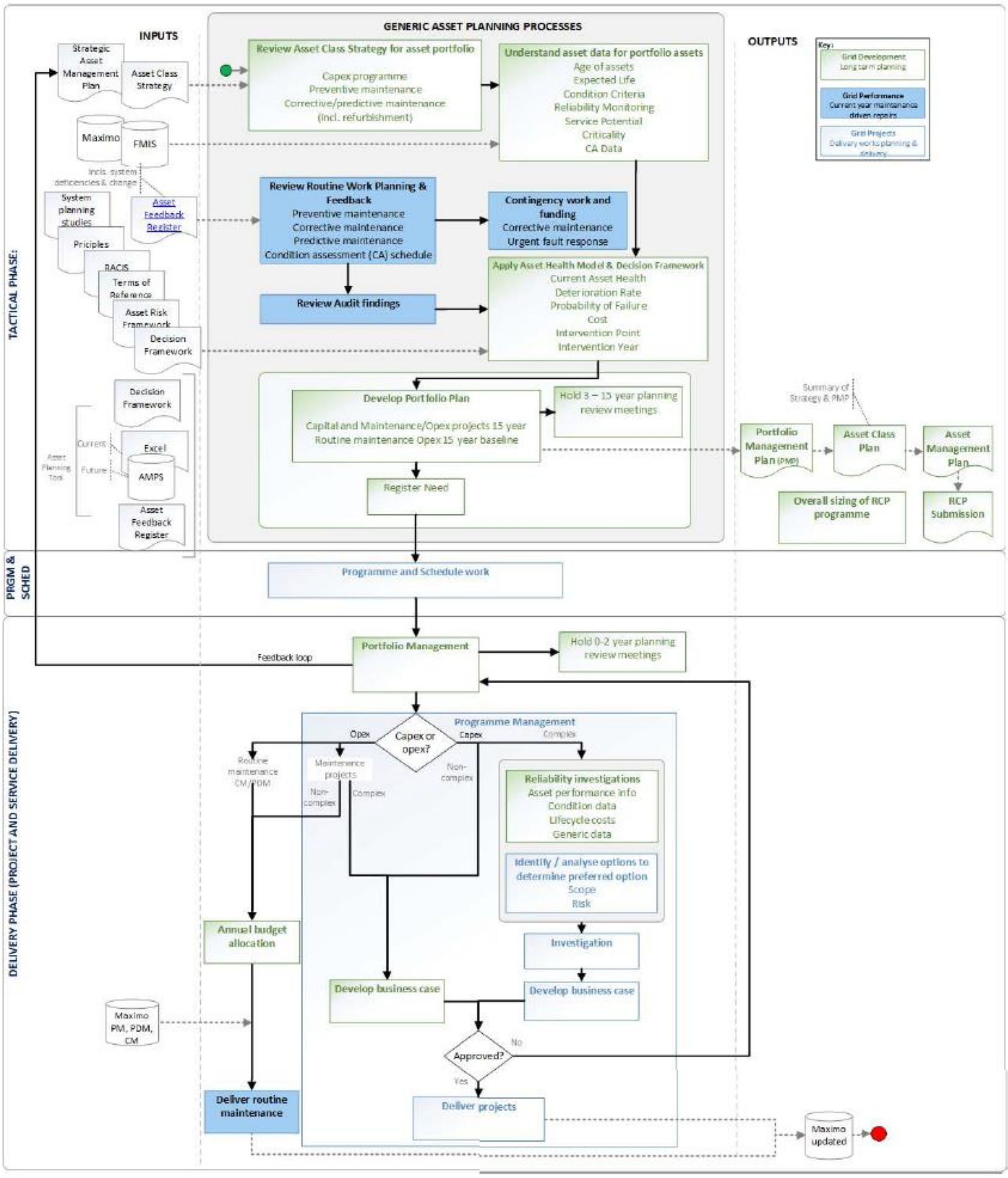
- Attachment B – Transpower's asset planning framework
- Attachment C – more details regarding Transpower's identified programmes[1]
- Attachment D – Transpower's cost estimation practices.

[1] The Terms of Reference for our independent verification role requires us to review Transpower's proposed base capex and opex allowances for RCP3 with emphasis on identified programmes. The purpose of the identified programmes is to provide more in-depth qualitative and quantitative information about the formation of a large subset of base capex and opex.

B Transpower's asset planning framework

Figure 1 describes the asset planning framework used by Transpower in managing and planning activities for lines, substations, secondary systems and buildings and grounds.

Figure 1 Asset planning process[2]



2 Transpower, *Portfolio Framework*, March 2018, section 1.13, Figure 1, p. 8

C Supplementary information used in our assessment of the identified programmes

The following sections review the following details for the identified programmes:

- strategic objectives, measures and performance
- asset population
- asset health and condition knowledge
- state of the assets.

C.1 Power transformers

C.1.1 Strategic Objectives, Measures and Performance

The overarching objective for power transformers is that they operate safely and reliably, at least whole-of-life cost. To achieve this, our key objectives are:

- Asset Performance: Winding failure rate for transformer banks less than 0.3% per annum on a rolling 10-year average basis (approximately 1 event per annum). The current 10-year average rate is 1.25 per annum.
- Asset Performance: Unplanned outage rate less than five events per 100 power transformers in service per annum (approx. 18 events per annum, which is the average over recent years).
- Safety: Zero workplace fatalities or permanent disablement caused by defects, failures or explosions of power transformers. Our current rate is zero.

Figure 2 below shows a ten-year trend of the number of incidents that resulted in a transformer being removed from service, either automatically, or manually but with less than 24 hours' notice, where the transformer was the faulted item.

The improvement in transformer failure rates is evident in the performance trends.

Figure 2 Power transformer forced and fault outage

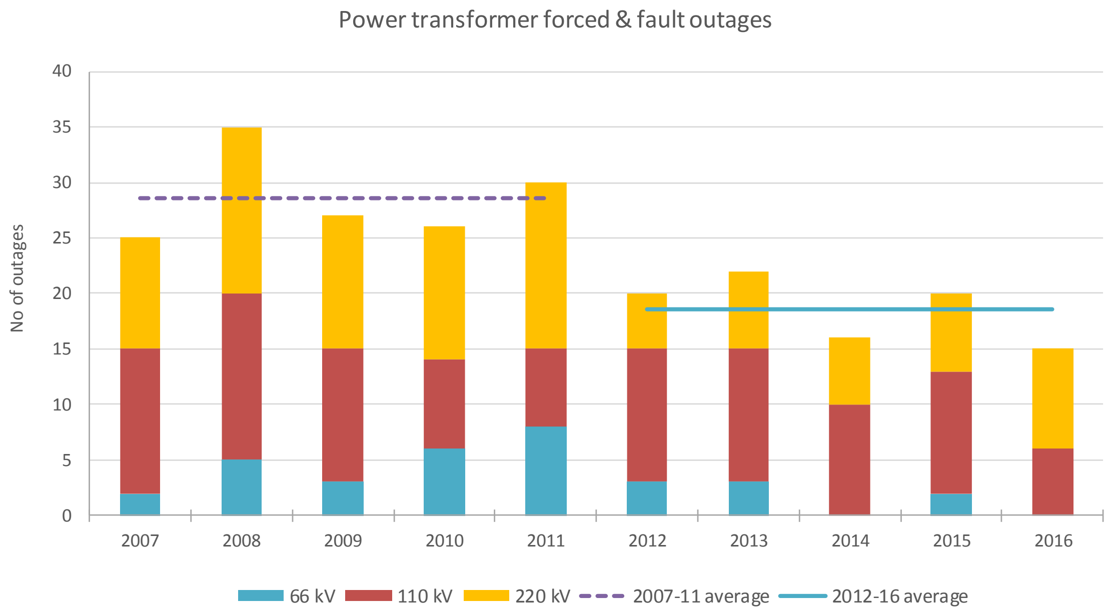


Figure 3 shows the trend of transformer forced and fault outages. Since a transformer replacement programme started in 2008, targeting old and poor condition single-phase units that generally forced and fault outage rates have decreased. Tap changer and Bucholz fault caused outages have been significantly reduced; although these remain the most common causes of power transformer outages since 2000 (refer Figure 4).

Figure 3 Power transformer fault outages

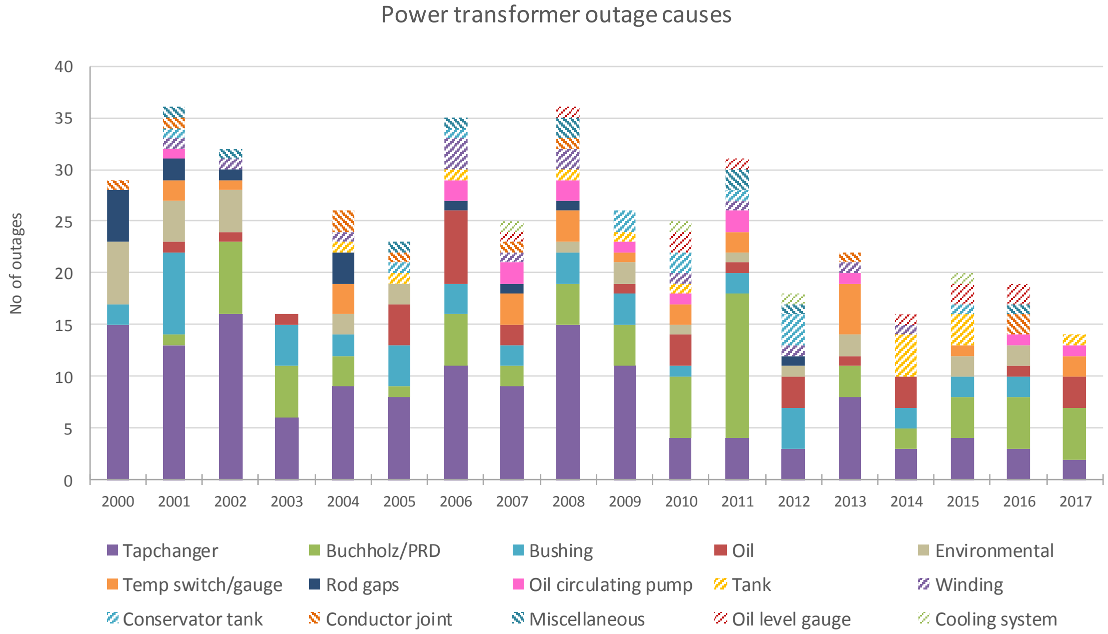
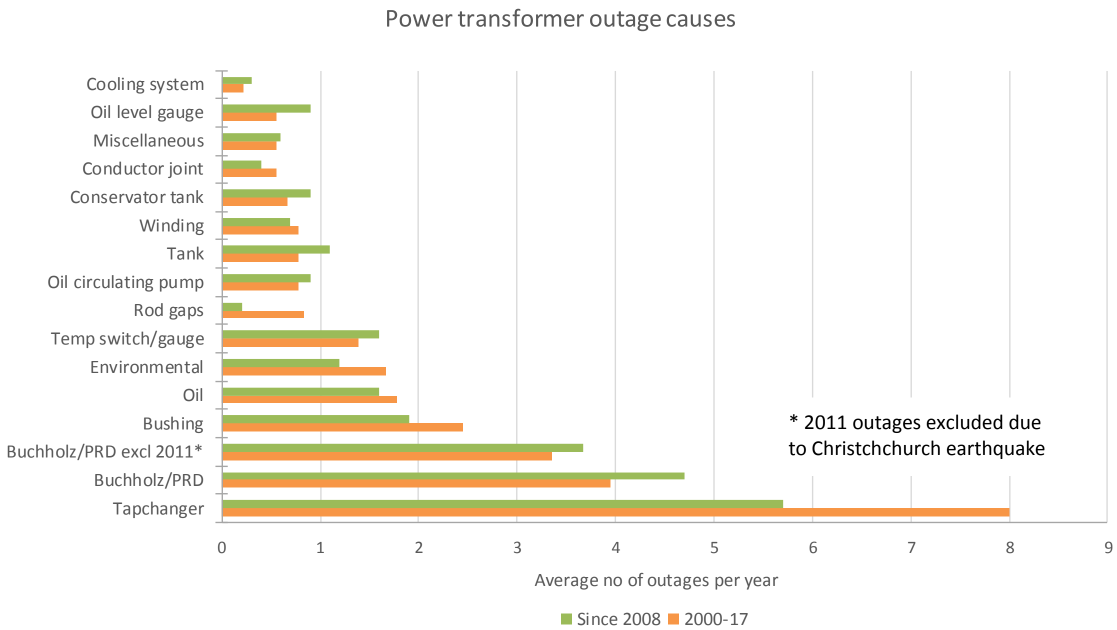


Figure 4 Power transformer outage causes[3]



3 Based on power transformer outage causes shown in Figure 3. Outages related to Buchholz and pressure relief devices (PRDs) shown including and excluding 2011 outages due to 2011 Christchurch earthquake and potential susceptibility of these protection devices incorrectly operating due to severe seismic activity.

No winding failures have occurred since 2014, which is a significant improvement on the historic trend; however, Transpower is still averaging approximately one per year over the past 10 years. This could be somewhat influenced by past replacement of poorly designed transformers, but it could also alternatively be explained by stochastic behaviour and should be measured over a long timeframe.

C.1.2 Asset Population

The age population of transformers is shown in Figure 5 and Figure 6 below.

The age profile by voltage shows that the transformer banks older than 40 years are mostly in the 110 kV network. The age profile by number of phases shows a significant transition between 40 and 50 years. The transformer banks older than 50 years are almost all single-phase types. The power transformer banks less than 40 years old are mostly three-phase types. The two-phase banks are traction supply transformers.

Figure 5 Power transformer age profile by primary voltage

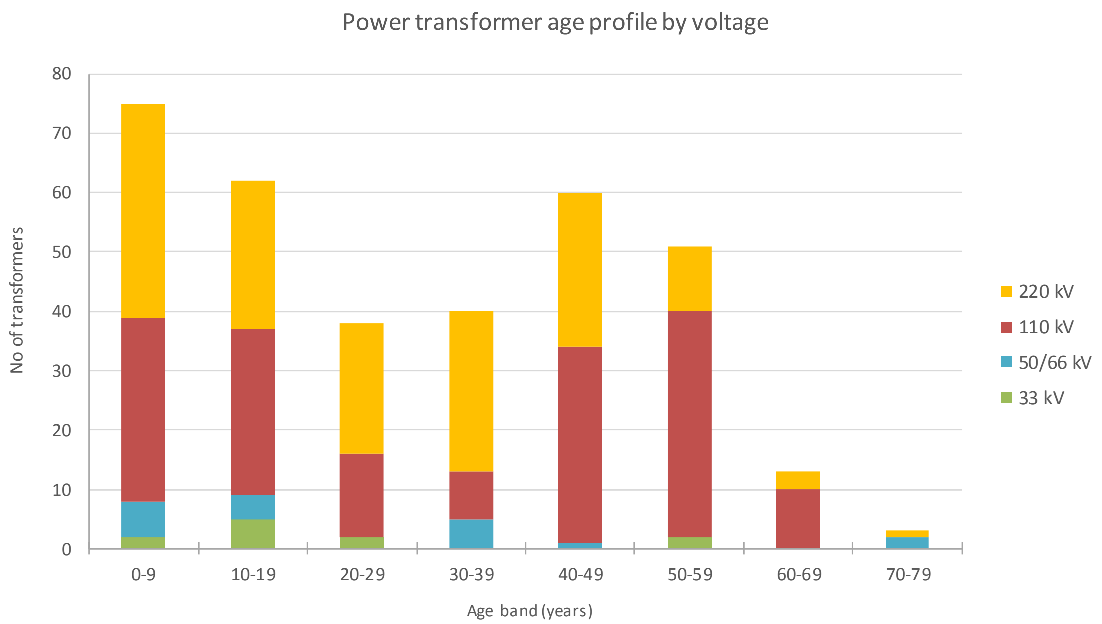
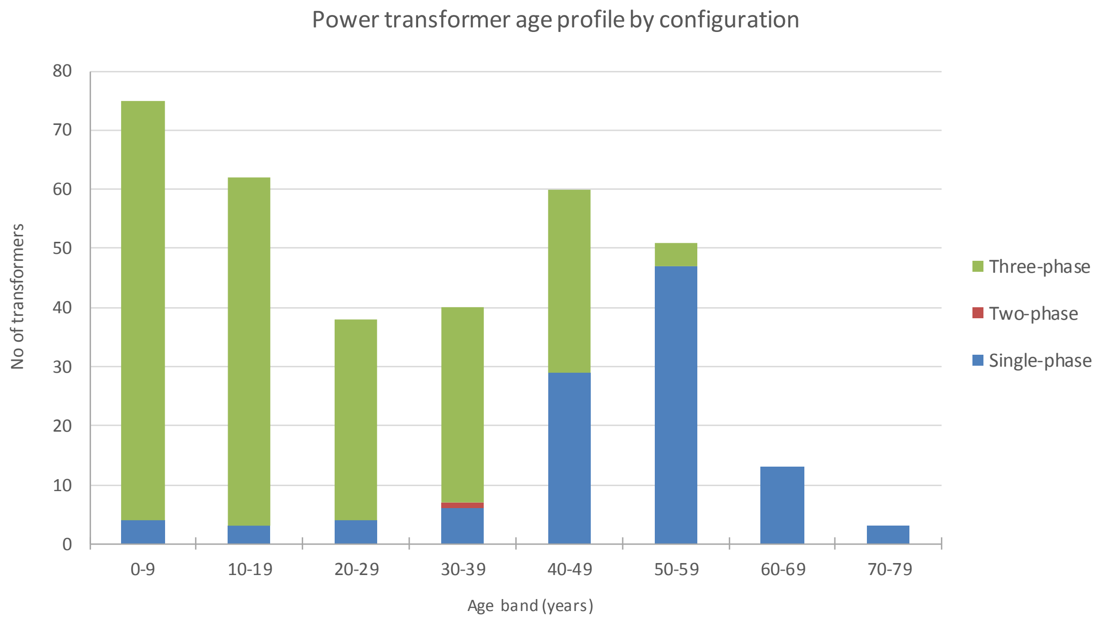


Figure 6 Power transformer age profile by configuration



C.1.3 Asset Health and Condition Knowledge

An asset health model has been created using Condition Based Risk Management (CBRM) that splits the power transformer into its three major components:

- tank and active part
- tap changer
- bushings

The investment planning approach for transformers is generally based on undertaking asset health modelling with CBRM. Those assets that are identified with poorer health then undergo detailed site specific consequence modelling. This establishes the risk that each unit presents at present and into the future.

The asset health model is based on the Common Network Asset Indices Methodology (CNAIM) approach, published by the Office of Gas and Electricity Markets (OFGEM), in the United Kingdom (commonly CBRM). The methodology details the inputs, calculations, and calibration parameters to be used in the calculation of asset health.

The standard methodology for power transformers in the CNAIM approach incorporates a health model for the tap changer, a health model for the rest of the power transformer (i.e. main tank and active part), and then combines the output of them together. Transpower has extended this approach further to incorporate a specific asset health model for the transformer bushings. Hence, the asset health of the transformer system requires consideration of the asset health of the three major components.

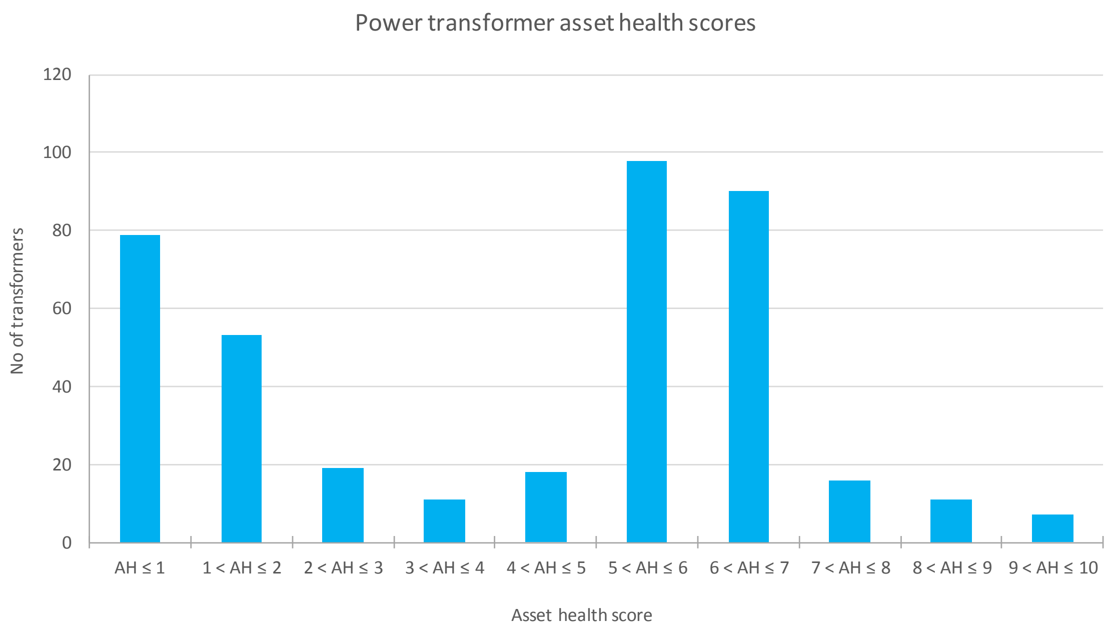
The condition of transformers is routinely reviewed following inspections and routine oil, electrical and mechanical testing of components of the transformer. These are incorporated into the asset information management system and used in asset strategy planning and maintenance interventions.

C.1.4 State of the Assets

Figure 7 shows that the asset health of major power transformers is generally good, with only a very small proportion (approximately 5% of population) with poor asset health (scoring 8 or above).

The population fits into two distinct health bands, those in good health (asset health score less than 5 - approximately 45% of population) and those with an asset health between 5 and 8 (approximately 50% of population), often related to aged bushings. Hence, there is an opportunity for life extension for transformer with an AHI of 5 and 6.

Figure 7 Power transformer current asset health scores



All of the power transformers with a health score of eight and above fit into the following categories:

- they are already planned for replacement or other major intervention, including relinquishment, or abandonment or are subject to a customer enhancement in RCP2 or RCP3;
- intervention relies on yet to be confirmed customer commitments;
- previous fault history is providing poor test results to the model and these results are no longer completely relevant;
- measured test result data entry errors;
- gassing in the transformer is being monitored operationally and is not such that would justify replacement or significant intervention yet; and
- data errors in observed external condition assessment which highlight defects rather than true poor condition have not been corrected.

C.2 Outdoor 33 kV switchyards: Outdoor to Indoor Conversion

C.2.1 Strategic Objectives, Measures and Performance

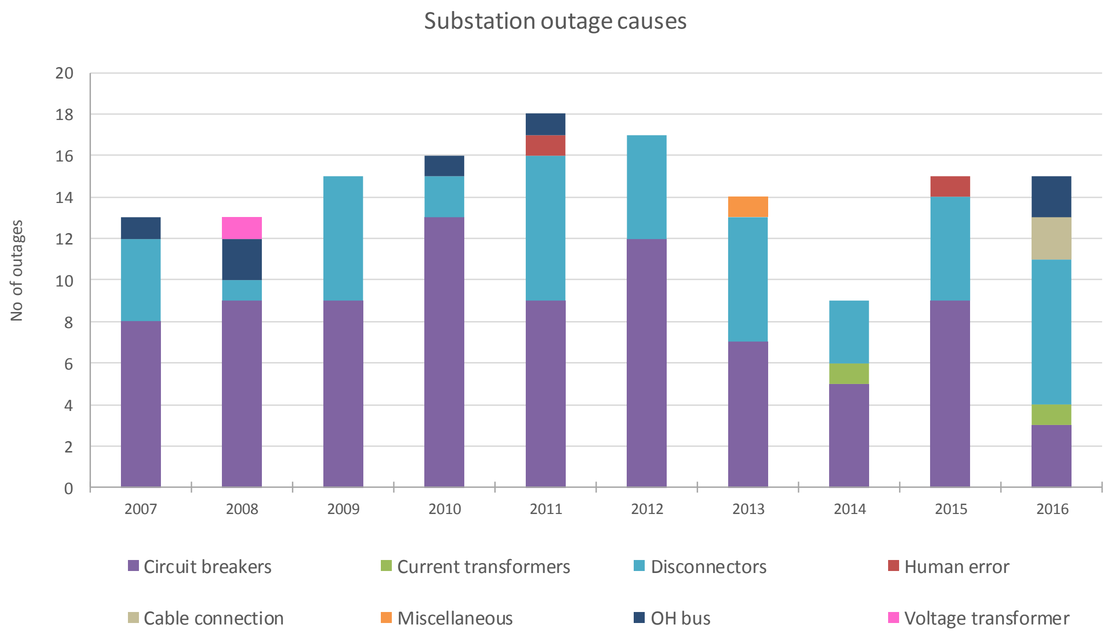
The overarching objective for outdoor 33 kV switchyards is to provide a safe working environment, and operate reliably, at least whole-of-life cost. The key objectives are:

- Asset Performance: number of fault and forced outages caused by outdoor 33 kV equipment will be reduced to less than five per annum by 2025 (currently averaging approximately 15 events each year)
- Safety: zero fatalities and injuries causing permanent disability at outdoor 33 kV switchyards. The risks of safety incidents will also reduce by removal of hazards

With respect to asset performance, circuit breakers are the leading cause of unplanned outages over the last 10-year period that supports the use of circuit breaker asset health as a proxy for the condition of the entire switchyard. Ageing disconnectors are the second most common cause of forced and fault outages, and have been a significant cause of outages in recent years.

Bus faults in outdoor 33 kV structures have occurred about twice a year on average, and have caused significant losses of supply previously. The worst incident in the past 10 years occurred at Glenbrook Substation on 2 December 2010, where 3.4 system minutes were lost following the failure of a busbar insulator.

Figure 8 Substation fault outages



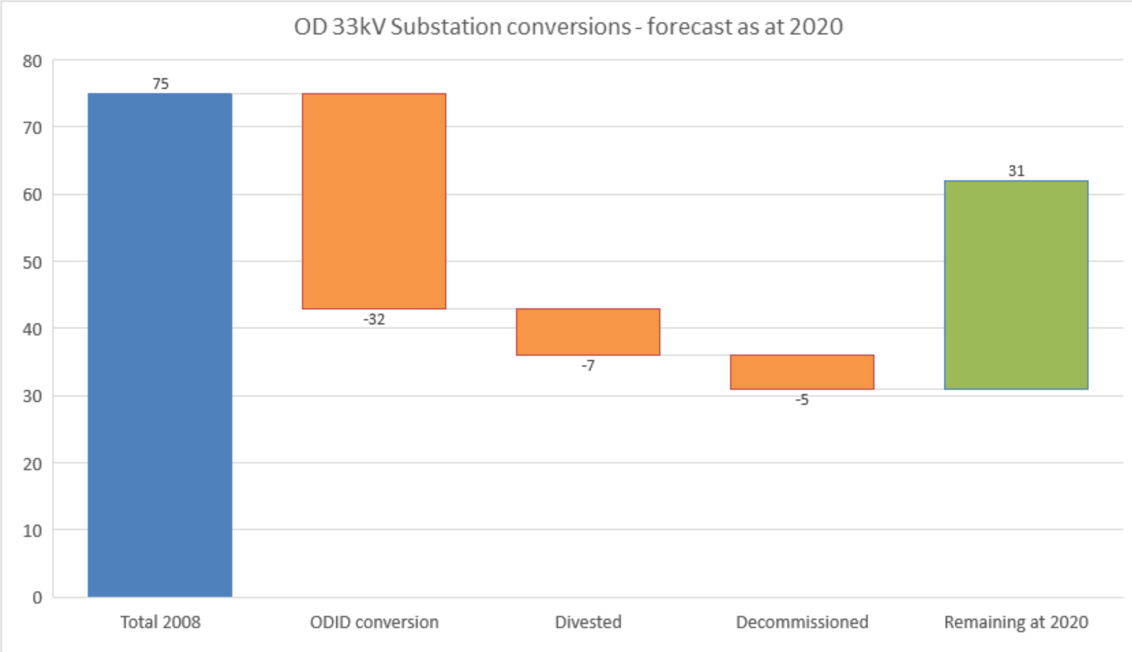
There have been four fatalities of maintenance workers connected with outdoor 33 kV switchyards in the past 35 years. Common factors in all these tragic incidents were; very small maintenance safety clearances, working at heights, the need for workers to climb into the structure, operational or procedural errors.

The last serious near-miss safety incident involving outdoor 33 kV equipment occurred at the Penrose substation on 22 November 2015. Fortunately, the maintenance switcher was not injured.

C.2.2 Asset Population

In 2008, there were 75 substation sites with outdoor 33 kV or 22 kV structures. The programme of outdoor-to-indoor conversions is continuing, in line with the current strategy. By 2020, 32 outdoor-to-indoor conversions will have been completed, and the overall programme will be completed by 2025.

Figure 9 Outdoor 33 kV substation conversions to 2020



C.2.3 Asset Health and Condition Knowledge

There is no asset health model for the entire outdoor 33 kV switchyard system given it is a collection of many asset classes and priority is assigned to the risk and criticality of each site. Circuit breaker asset health is a proxy for the condition of the entire switchyard in the asset health model. For 33kV switchyards, this data and in-field assessment of condition of the equipment as a whole is considered along with safety risks to determine priorities for replacement in the programme.

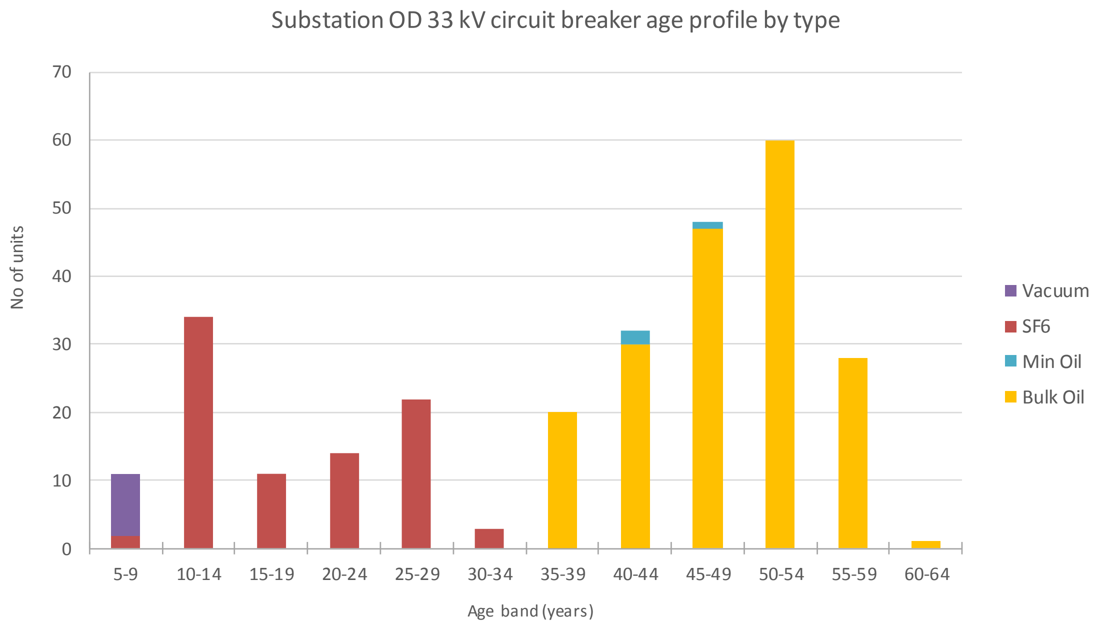
Asset condition issues of particular concern include the deterioration of brown porcelain cap and pin insulators that support 33 kV buswork, disconnectors and earth switches. Failures of these types of insulator have caused safety and reliability incidents. Deterioration of concrete structure support posts is an emerging issue at some sites.

C.2.4 State of the Assets

The current goal is 31 outdoor 33 kV switchyard sites to be remaining in service at the commencement of RCP3 in 2020. Of these, around 18 sites are forecast to remain as outdoor switchyards. These sites are small installations where the hazards of close approach to live equipment can be effectively managed, or are N security sites where safe access for maintenance is achieved during a total shutdown. Some outdoor switchyards are also being divested to customers.

Outdoor 33 kV switchyards consist of multiple asset types such as structures, buswork, disconnectors, circuit breakers, and instrument transformers. Each of these asset types have different life expectancies, which are outlined in the relevant PMP. These life expectancies range from 45 years (circuit breakers and instrument transformers) to indefinitely (steel and aluminium structures assuming they are painted and repaired).

Figure 10 Outdoor 33 kV circuit breaker age profile by type as at 2020



The outdoor 33 kV switchyards range in age from 35 to 68 years old.

C.3 TL structures

C.3.1 Strategic Objectives, Measures and Performance

The tower painting portfolio is an intervention programme before degradation has reached a point where failure is possible. Performance of tower structures is historically very good with very few failures. No failures are attributable to steel condition; and Transpower have not identified any specific asset performance measures applicable to this programme of works.

Insulator Services Performance objectives are:

- Safety Performance: Zero injuries caused by insulator and fitting failures - this aligns with the historical average
- Service Performance: Average annual unplanned outage rate (expressed in events for each 100 cct-km each year) less than 4.0 for 110 kV lines and 1.5 for 220 kV lines

Historical average is 4.0 and 1.6 over past 10 years. Since January 2000 to date, there have been a total of 114 insulator failures. Of these, 17 have resulted in conductor drops and the remaining failures were as a result of non-technical issues such as vandalism, bird strikes or extreme weather.

The structure portfolio objectives are:

- Service Performance: Unplanned outages caused by pole or crossarm failures of 1.0 per year. Historic performance is 13 over past 10 years, or 1.3 p.a.
- Service Performance: Tower failure rate of one failure per annum or less. Historic performance is 0.75 tower failures per year.
- Safety: Zero injuries caused by tower or pole failures.

C.3.2 Asset Health and Condition Knowledge

Since 2013, further development of the corrosion zones, intervention points, and enhanced condition assessment data has contributed to a revised asset health model to forecast both the backlog and forecast workload ahead. Corrosion zones and intervention point adjustments have been included in the latest asset health model.

Inclusion of the enhanced CA data is progressing aligned to the 8-year CA cycle. Transpower is 5 years into the 8-year cycle and have 74% of structures where the condition data can be utilised in the model. Ongoing review and refinement of the model is informed by specialist knowledge and findings using the revised composite asset Condition Code (CA) determination.

Transpower intends to continually review the linear degradation profiles used for painted structures with observed degradation rates to provide more accurate degradation profiles.

Intervention points for each corrosion zone were established earlier using the previous composite condition code for economic analysis and modelling. The introduction of the new approach from 2013 has introduced a revised data set that when aggregated to a single code may not represent the true steel condition and alignment with intervention points. While this new approach improves the ability for modelling it introduces some risks which would be overcome with in field condition assessments just prior to the modelled intervention points.

Recent data quality initiatives for towers structures have been completed with key data fields for the asset health model now vetted and available in Maximo or the data warehouse.

The data on the exact age of each insulator strong is not used in forecasting; inferred age (expected life) is made use of. The current asset health model is based on degradation curves determined from historical data, categorised by corrosion zone.

One of the main identified opportunities for improvement is to conduct an end-of-life forensic CA validation. This will enable Transpower to determine whether an insulator that was replaced, based on a forecasted AHI8, corresponds to CA20. The curves can be improved for the various corrosion zones, thereby improving the model to produce more accurate volumes of work. A position may be reached where a measure for AHI accuracy can be established following forensic feedback after asset replacement programmes and field condition assessments.

Transpower is investigating several opportunities to improve efficiency in the insulator programme by aligning works to ensure least life cycle cost and to minimize land owner interruptions. These have been outlined throughout the Insulator Porfolio Management Plan document [ERR17 P34].

The degradation curves for insulators used in the health model are key in determining the forecast of work to be done. Improvements to the curve will assist with better forecasting (volumes of work) and obtaining closeout condition assessments is thought to significantly improve the degradation curves.

There are plans to review the health model for poles over the next two years to ensure that it provides optimal intervention points.

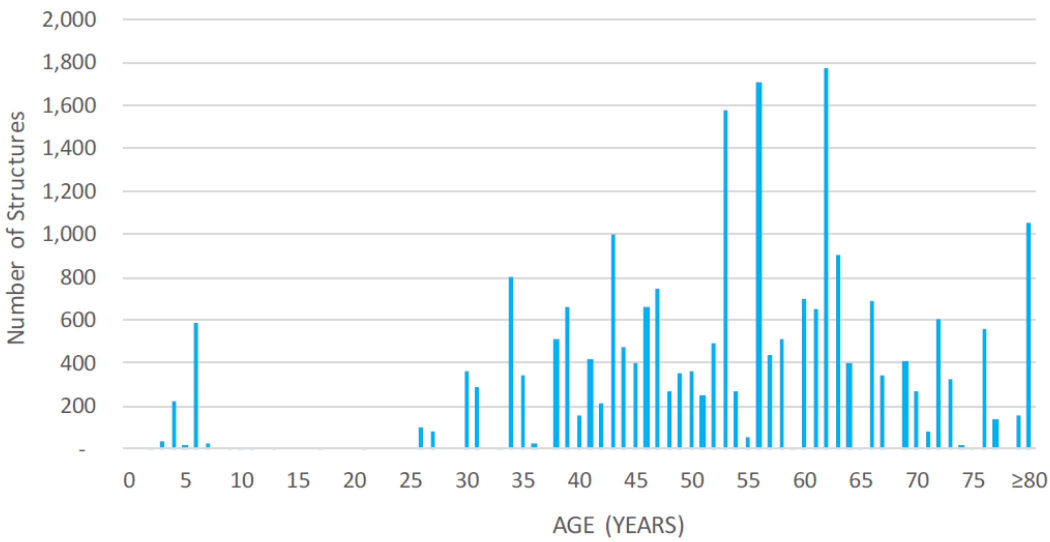
C.3.3 State of the Assets

With the average age of towers structures at 51 years, the majority of tower structures are past an early intervention stage, hence the initial painting of towers is increasing to prevent significant rusting. This is identified through assessment of all available steel condition codes resulting in a single aggregated average steel code being established for each structure as described above. This single code does not representing the worst coded steel condition; the structure will have many steel members below the single code or requiring replacement.

The 2267 unpainted towers in extreme, very severe, and severe corrosion zones will comprise the larger portion of the RCP3 new paint programme. The balance will be identified from the 10236 unpainted towers in the moderate zone. Many of the moderate corrosion zone towers are within 10 years of the typical time to first paint; this group of towers will be the significant portion of the new paint work in the painting programme over the next three RCP periods.

Figure 11 shows the age distribution of transmission towers. The weighted average age is 53 years.

Figure 11 Transmission tower age profile



Asset health scores reflect the expected remaining life of the tower steel (for unpainted structures), or the remaining life of the paint coating (for painted structures). We use different remaining life calculations for unpainted and painted structures. Unpainted structures use degradation rates for each corrosion zone based on observed condition codes, whereas painted structures use time based forecast per corrosion zone from last paint date. Objective is to paint or recoat towers with AH of 8 or greater.

Figure 11 illustrates the asset health of the steel towers.

Figure 12 Steel tower population asset health

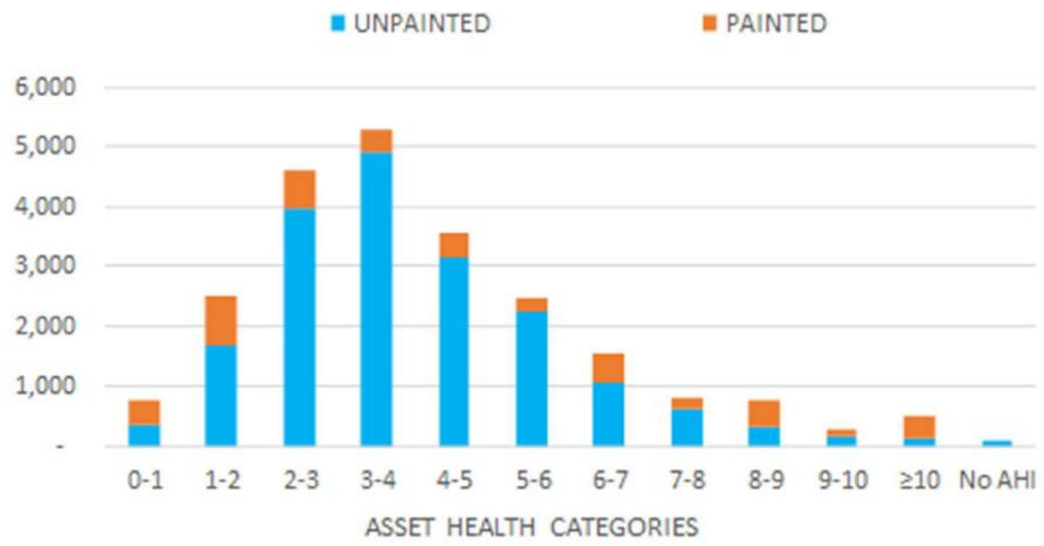
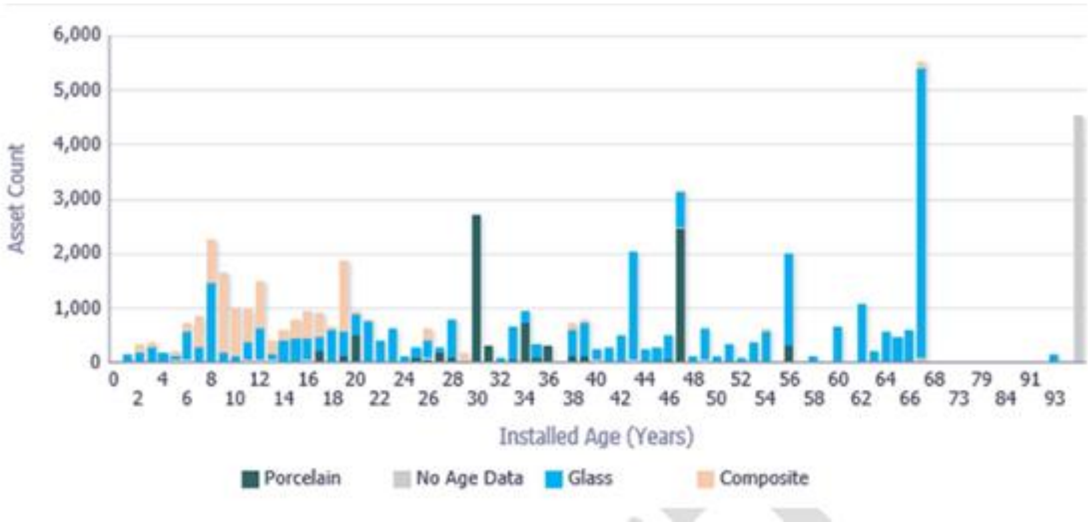


Table 1 Paint and recoat timeframes

Corrosion zone	Optimal CA at first paint	Typical age at first paint (years)	Typical duration between each paint (years)
Extreme	50	14	12
Very Severe	40	20	12
Severe	40	39	15
Moderate	30	56	15
Low	30	78	18
Benign	30	110	20

With 53% of towers located in a moderate corrosion zone and the average age of towers being 53 years, many of these towers are beginning to require their first paint and in another 15-20 years this large majority of towers will be requiring their second paint time. Hence an explanation of the increasing expenditure expected for RCP3 and not reaching a peak until post RCP5.

Figure 13 Insulator population age profile



Composites insulators have a longer life expectancy in extreme and very severe corrosion zones compared to glass. For this reason, Transpower's standard practice is to only install composite insulators in heavily polluted areas.

Figure 14 shows that there are much higher quantities of insulators in health bands between 3 and 8. This means the forecast expenditure over the next three regulatory periods is expected to increase to account for this.

Figure 14 Insulator asset health

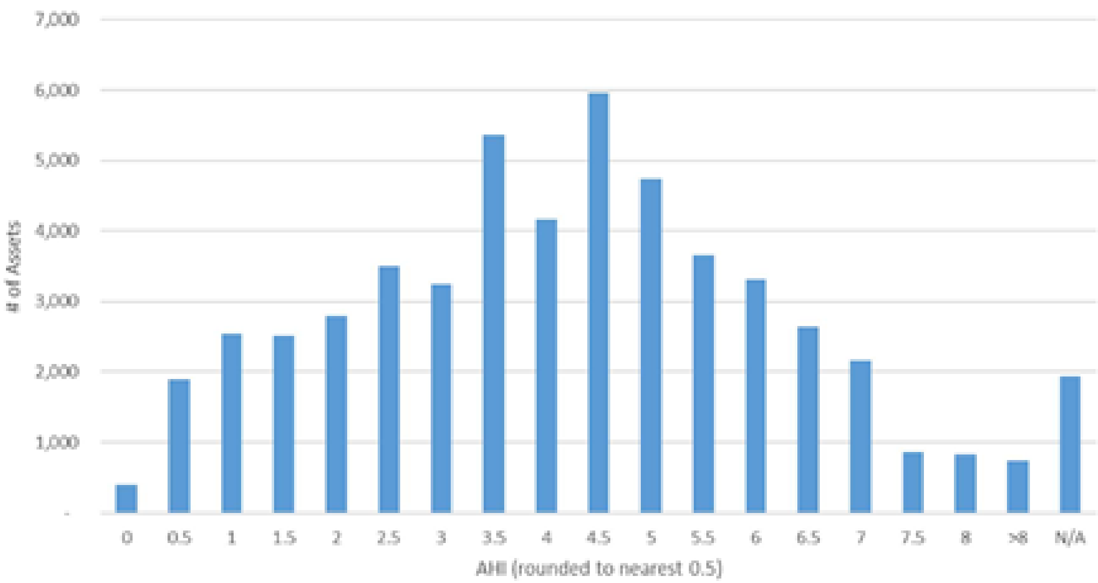


Figure 15 shows the age distribution of transmission poles.

Figure 15 Transmission pole population age profile

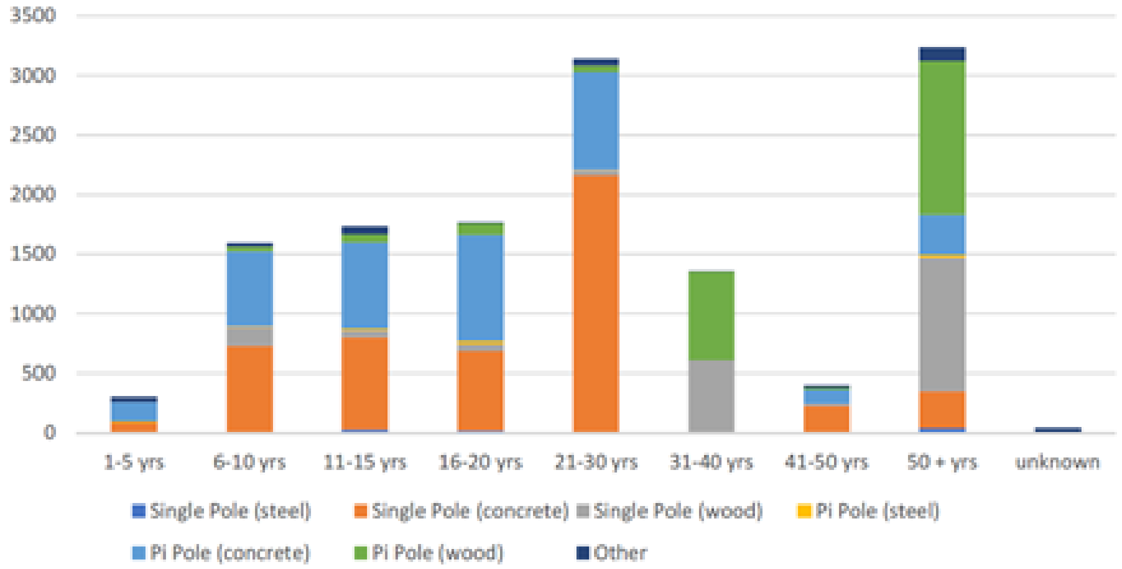


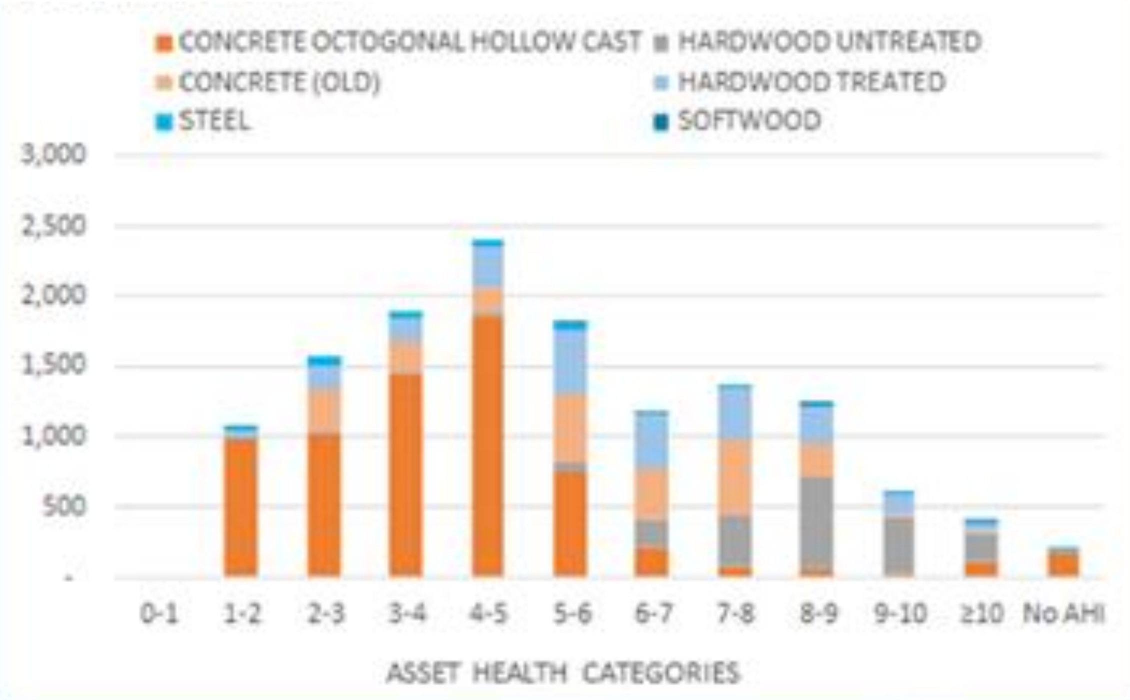
Table 2 shows the life expectancy of transmission poles.

Table 2 Transmission pole life expectancy

Pole type	Life expectancy (years)
Hardwood (untreated)	50
Hardwood (treated)	50
Concrete (old type)	70
Concrete (octagonal)	80
Steel (averaged across corrosion zones)	50

Figure 16 shows the asset health for transmission poles.

Figure 16 Transmission poles asset health



C.4 TL conductor & hardware

C.4.1 Strategic Objectives, Measures and Performance

The objectives for transmission line conductor and hardware are:

- Safety Performance: Zero injuries caused by conductor and hardware failures.
- Service Performance: Average annual unplanned outage rate for all causes (expressed in events for each 100 cct-km each year) less than 4.0 for 110 kV lines and 1.5 for 220 kV lines.

Historically, the average is 4.0 and 1.6 over the past 10 years. Generally conductor breaking has occurred during severe wind events, although some occurred because of snow build-up on the conductors. In three instances, conductors have failed when hit by lightning. Transpower has had 51 mid-span and five dead end joints fail mechanically since the early 1950s, seven of these since 2001. In almost every case, the cause was attributed to poor workmanship at the time of installation.

C.4.2 Asset Population

Table 3 illustrates the current age profile of conductors as represented in the Asset Class Strategy.

Table 3 Conductor population as at January 2018[4]

Conductor	Length	≤ 66 kV	110 kV	220 kV	350 kV	Total
Phase conductor	route - km	351	4,214	6,243	614	**11,422**
	circuit - km	621	5,088	9,276	1,167	**16,152**
Earthwire	route - km	13	541	2,546	336	**3,436**
Optical fibre	route km	0	0	457	214	**671**

Table 4 illustrates the current age profile of hardware.

Table 4 Conductor accessory population as at January 2018[5]

Accessory	Number
Mid-span joints	60,000
Dead end and other joints	40,000
Sub-conductor spacers	245,000
Dampers	317,000

Transpower has indicated that there is a difference between the hardware population within the asset information management system (AIMS), and the population provided above, which was based on subject matter expert knowledge. Work is underway across the organisation to update the AIMS database.

C.4.3 Asset Health and Condition Knowledge

Unlike other transmission line assets, which are discrete, conductors are linear asset, hundreds of kilometres in length. The occasional corrosion bulge can be removed; however, when widespread corrosion bulges occur in a span or section, replacement is required.

Loss of tensile strength is the most common failure mode in ACSR, although if the aluminium is severely deteriorated the final failure mode occurs when a steel core attempts to carry circuit current that is not designed for.

4 Document [**Error! Reference source not found.**], section 6.1, p. 14

5 Ibid., p. 15

Transpower has developed an asset heath model to predict end of life for each span of conductor and earthwire. The model initially uses the expected life for each conductor type within each corrosion zone. The model is used for forecasting longer term expenditure forecasts and trigger points for field condition inspections. Transpower does not currently have asset health models developed for conductor hardware, relying on condition assessment codes for determining asset strategies.

As end of life approaches, more detailed inspections are carried out to obtain a more accurate condition assessment score. Results of these investigations are incorporated back into the AHI model. Transpower still carries out regular condition assessments on the conductor and hardware fleet. The assessments produce a condition assessment score ('CA') for various components on a scale from 100 (new) to 20 (replacement or decommissioning criteria).

New lines are first assessed just prior to expiration of the defects liability period. Thereafter, line assets are generally assessed every eight years and pole lines every six years.

When the CA score of any component is less than 50, the assessment frequency is increased. The aim is to ensure that no component can deteriorate by more than 50% between assessments (such as from CA score 60 to 30). Sites with very high degradation rates or criticality may be assessed more frequently.

Due to costs and complexity Transpower does not have detailed CA data for all conductor spans on the network. Over RCP 2 and RCP 3 Transpower intends to increase this programme of work to help ensure that suitable data supports replacement works and support better long-term planning.

One issue is that not all assets coded CA20 will degrade at the same rate, even if in the same environment. In practice, localised sections of conductor at or below CA20 may be left in service, with an inspection and repair programme in place. The strategy for each section of conductors therefore has to be determined on project-by-project basis.

Issues associated with quality data include:

- Obtaining condition data for conductor fleets is difficult and costly, as it involves close non-destructive and destructive testing processes
- There is a lack confidence in the recorded numbers and locations of key assets like conductor joints, and improving the quality of this data set will be an area of focus

- Condition data quality is also an area of continuous improvement for other conductor and hardware assets, e.g. marker balls, which show that most are well beyond replacement criteria

There are known data quality issues and data availability issues with TL conductor and hardware assets. A summary is shown in Table 5.

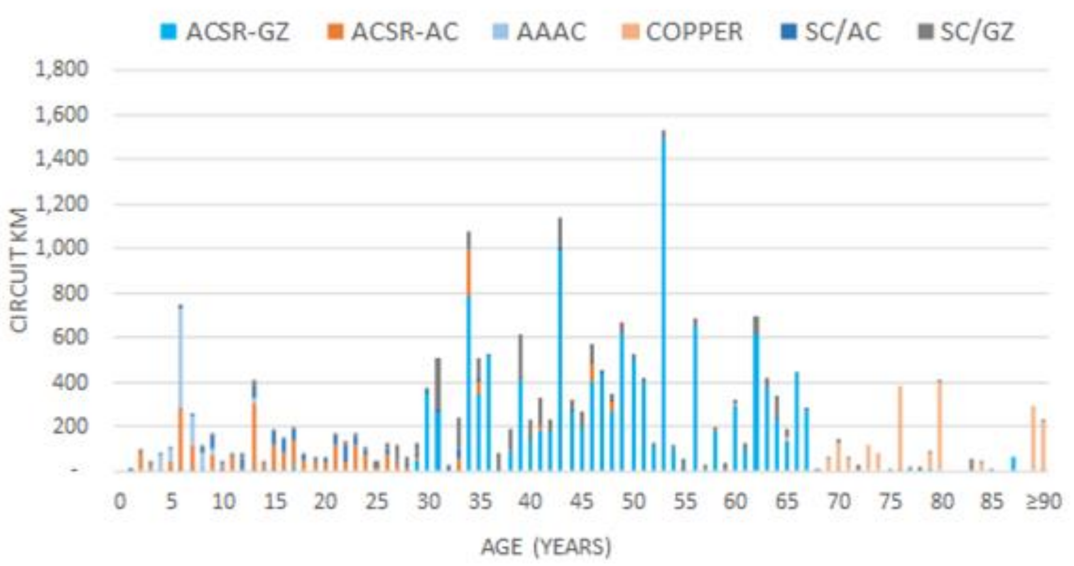
Table 5 TL conductor data quality & availability

Asset type	Base asset data	Installation date	CA data availability
Conductors	Good	Good	Poor
Earthwires	Good	Poor	Average
Aerial communications cables	Average	Poor	Average
Joints	Poor	Poor	Average
Other hardware	Good	Poor	Good

C.4.4 State of the Assets

The current state of the conductors and hardware portfolio are characterised by the age of many transmission lines built between 1950-1980 and installed in a wide range of environments across the country. Many assets in the TL conductor portfolio are predicted to reach end of life over the next 15-20 years, although there is significant uncertainty in this prediction. Figure 17 provides the age profile of conductor types installed on the Transpower network.

Figure 17 Conductor age profile as at March 2018



The expected conductor life of the most common ASCR conductor in the most common moderate corrosion zone is 69 years as shown in Table 6.

Table 6 Conductor life expectancy (years) by type and corrosion zone

Type	Benign	Low	Moderate	Severe	Very Severe	Extreme
ACSR-GZ Greased	120	93	69	51	38	27
ACSR-GZ Greased Holiday	84	63	44	31	22	15

Figure 18 and Figure 19 illustrate the condition of Transpower's conductors as represented in the Conductor and Hardware Asset Class Strategy. The age profile illustrates the current high volume of ASCR conductors on the network would be expected to be generally in good condition but will be entering an end of life period over the next 20 years.

The condition codes recorded for the conductor fleet is consistent with the age of the conductors fleet.

Figure 18 Conductor condition by type

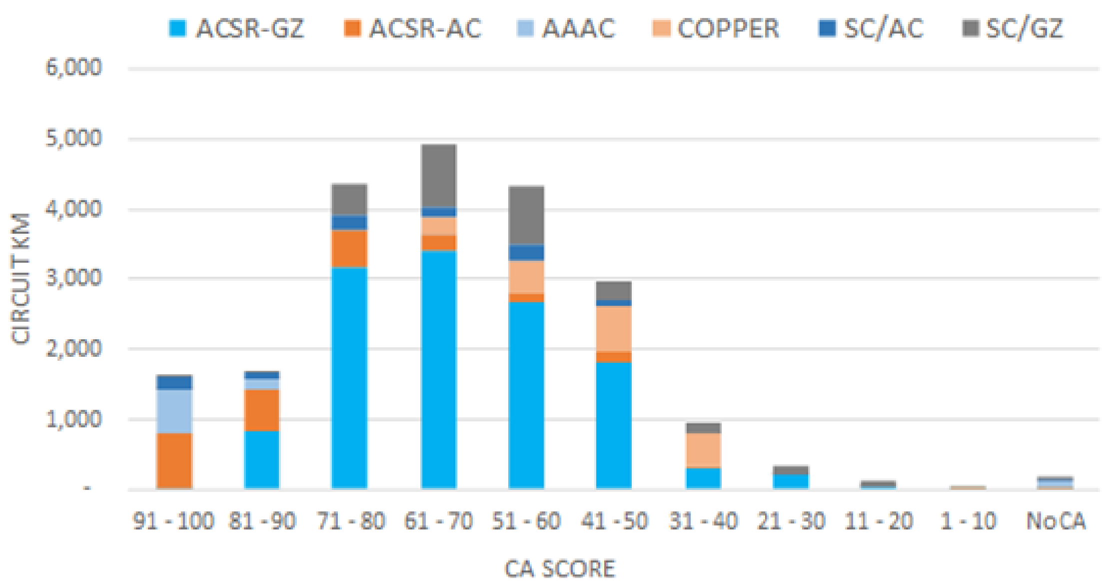
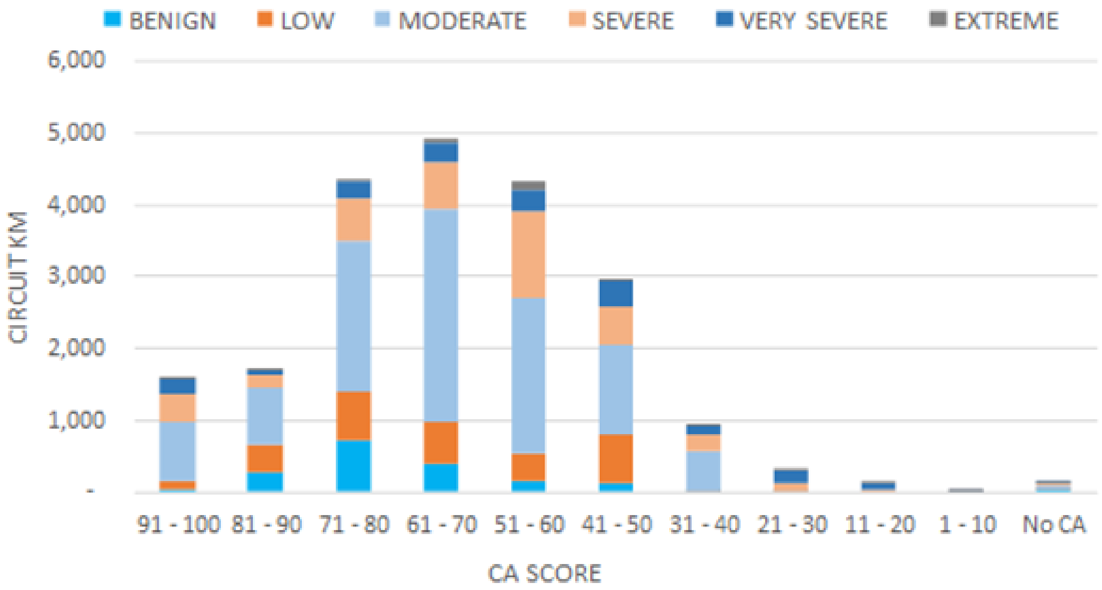


Figure 19 Conductor condition by corrosion zone



C.5 HVDC

C.5.1 Strategic Objectives, Measures and Performance

Key objectives and performance targets for the HVDC facility are:

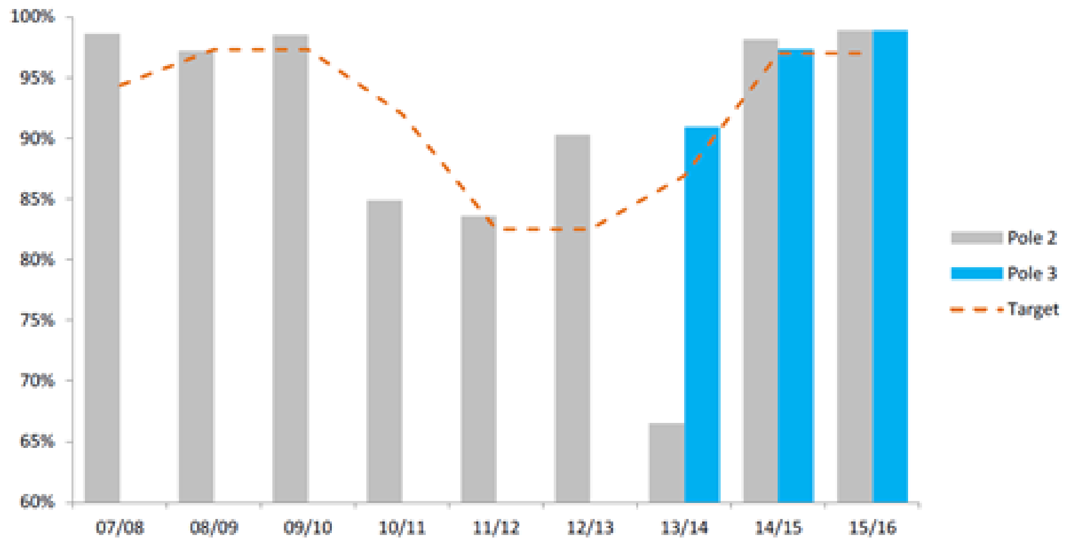
Availability:

- Bi-pole availability of 98.5% or greater.
- Minimise impact of major submarine cable failures by maintaining necessary resources to undertake a prompt 'cut and cap' operation, to reduce water propagation in the insulation, in the event of a fault.

Objectives in the following areas are also defined for safety, service performance, cost performance, customers and stakeholders, and asset management capability.

To date the HVDC service performance objective has been achieved in RCP2 with an annual availability greater than 98.5%. With the planned HVDC projects in 2019/2020 financial year Transpower has stated that the availability target cannot be achieved with the required outages for these projects. Similarly in RCP3, the planned Pole 2 refurbishment work will affect the HVDC availability due to longer outages for converter transformer refurbishments and primary asset replacement works. Appropriate RCP3 availability targets are currently being investigated by Transpower.

Figure 20 HVDC link annual availability



C.5.2 Asset Population

Table 7 sets out the population of the main asset types in the HVDC asset class.

Table 7 HVDC asset population

Asset type	Quantity	Notes
Converter stations	2	1 at Benmore and 1 at Haywards; each substation has 2 Poles/Converters
Electrode stations	2	1 at Bog Roy and 1 at Te Hikowhenua
Cable stations	2	1 at Fighting Bay and 1 at Oteranga Bay
Submarine cables	3	38 km per submarine cable

C.5.3 Asset Health and Condition Knowledge

Due to the unique and diverse nature of the HVDC assets, asset health modelling is not applicable or practical. HVDC assets consist of various asset types in small populations which doesn't provide sufficient data to develop an accurate asset health model. Many of these assets are uniquely designed for HVDC operation and AC asset health models cannot be directly applied.

To support decision making, HVDC assets are subject to specialist and individual condition monitoring and assessment.

C.5.4 State of the Assets

Table 8 shows the install dates and the associated life expectancy of the assets.

Table 8 HVDC Converter Stations - installation date and life expectancy

Asset type	Station	Installed	Life Expectancy
Converter station	Pole 2 converter stations (Haywards)	1991	50 years
	Pole 2 converter stations (Benmore)	1991	50 years
	Pole 3 converter stations (Haywards)	2012	50 years
	Pole 3 converter stations (Benmore)	2012	50 years
Cable	Cable 4	1991	40 years
	Cable 5	1991	40 years
	Cable 6	1991	40 years

The knowledge of asset condition or age is as follows:

- As Pole 2 has a design life of 30 years, most of the Pole 2 assets are reaching their end of design life.
- The oil filled porcelain bushings have a design life of around 30-35 years and replacements are required for Pole 2 life extension. Porcelain bushings have a high risk of a failure, increasing the fire risk in the valve hall.
- Pole 3 buildings are relatively new and do not require any remedial work in the near future. Pole 2 buildings have undergone some repair work across RCP 2. Roof repairs, gutter work, downpipe replacements are some examples of building work carried out in RCP2.
- The cable station buildings require strengthening to improve the resilience of the HVDC system to tsunami risk and the threats of seismic activities. Work is being carried out across RCP2 and RCP3.
- The extreme coastal conditions at the Oteranga Bay and Fighting Bay cable station stations have led to severe corrosion of the exterior walls and roof cladding of the cable station building. These issues are being addressed as part of the building refurbishment works in RCP 2.
- Submarine cables. Surveys show that the three power cables are externally in good condition and generally well supported by the seabed. Due to the nature of the marine environment, unsupported cable sections and corrosion around areas of exposed cable armouring is expected. The life expectancy of the cables is

difficult to estimate and determine through cable testing due to the number of factors affecting the rate of deterioration and detection.

C.6 Reactive plant

C.6.1 Strategic Objectives, Measures and Performance

The overarching objective for Synchronous Condensers is that they operate safely and reliably, at least whole-of-life cost. The key objectives are set out below.

- Service Performance: Average annual availability greater than 96.0% for each Haywards synchronous condensers including planned unavailability of 3.5% or less and unplanned unavailability of 0.5% or less
- Service Performance: Less than 2 unplanned outages and 2 planned outages for each synchronous condenser each year.
- Safety: Zero fatalities or injuries causing permanent disability caused by defects or failures of synchronous condensers assets, or the hydrogen or carbon dioxide hazards associated with the gas-cooled machines

The overarching objective for our power electronics devices (STATCOMs and SVCs) is to reliably provide reactive power as required for grid stability under transient or abnormal conditions. The key objectives are set out below.

- Service Performance: 98% or better availability of SVCs and STATCOMs and less than three forced and fault outages each year from each SVC or STATCOM
- Safety Performance: No fatalities or injuries causing permanent disability from operation or maintenance of power electronics devices

The overarching objective for the capacitors and reactors assets is achieve an appropriate level of reliability and to avoid major failures, at least lifecycle cost. The key objectives are set out below:

- Service Performance: Less than ten forced and fault outages each year across the capacitor bank fleet (previous ten year average is 6.1)
- Safety: No fatalities or injuries causing permanent disability arising from operation or maintenance of reactive power assets
- Asset Performance: 98% or better availability of SVCs and STATCOMs and less than three forced and fault outages each year from each SVC or STATCOM

- Asset Performance: Average annual availability greater than 96.0% for each Haywards synchronous condensers including planned unavailability of 3.5% or less and unplanned unavailability of 0.5% or less

- Asset Performance: Less than 2 unplanned outages and 2 planned outages for each synchronous condenser each year

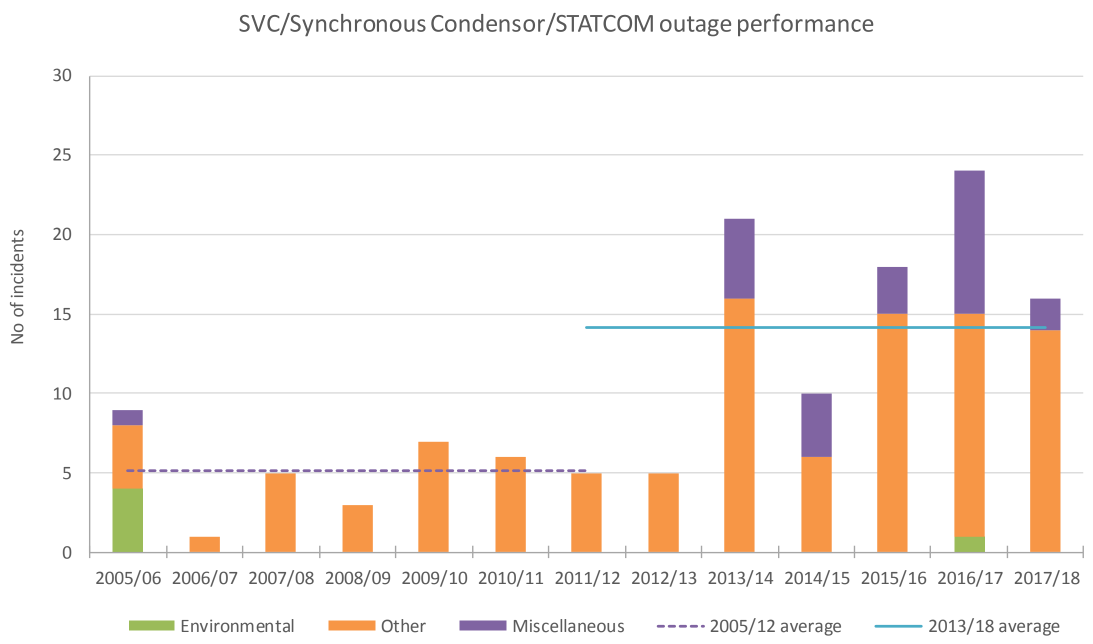
SVCs , STATCOMs , Synchronous Condensers

Transpower has experienced sever significant failures during the last few years with synchronous condensers. It indicated that these have been addressed. Our review confirms that these issues are not systematic failures.

The STATCOMs have performed well over the years with only minor problems such as air conditioning issues, corrosion, power module failures, and control system issues. Some of these issues are being addressed. Many recent STATCOM failures were related to temporary control system failures arising from temporary software, communication, or hardware failures.

The asset performance of SVCs has been satisfactory with both minor and major failures. However, the control and protection systems, cooling systems, and other auxiliary systems are in a poor state.

Figure 21 SVC/Synchronous Condensor/STATCOM outage performance



The Haywards synchronous condensers are of robust design and construction. In general, they have been reliable and often operate continuously for many months without incident. Some have operated continuously for more than 14 months before being shut down for minor servicing.

However, over the past 25 years, there have been several major incidents. Some of these incidents caused the machine to be unavailable for many months.

A failure of reactive power assets affects regions of the grid and, except in the worst case, is unlikely to cause a power outage. In the worst case, load shedding would be required to avoid stability issues resulting from lack of reactive support.

Capacitor Banks and Reactors

Transpower has five 1988 era Roderstein manufactured capacitor banks (1,000+ cans) installed in the Auckland region. Following identification of a manufacturing fault all of the defective cans were replaced in 1989. These banks had a relatively high failure rate compared to other capacitor banks.

Though major failures are rare, Transpower experienced a major failure at Islington SVC9 in 2016. 72 capacitor cans were damaged and required replacement following a fire in the SVC9 thyristor switched capacitor bank. The most likely cause of the initial fire was determined to be thermal and/or mechanical failure of a capacitor can bushing terminal connection which then resulted in loss and ignition of insulating oil.

As a consequence of this incident, a number of shortcomings in the design and selection of materials were identified resulting in recommended improvements to capacitor bank design with respect to the purchase specification. In addition, we updated our standard maintenance procedures for capacitor bank inspections and thermovision. A special thermovision survey was carried out nationwide on all capacitor banks from which we identified and corrected a number of defects. We also procured a new capacitor test set for Islington substation.

Another capacitor bank failure at Islington has caused damage to the capacitor bank structure and the unbalance current transformer (UCT). The root cause of this failure was found to be the use of under-rated insulators. Subsequent issues identified with capacitor bank protection schemes has initiated a review of the capacitor bank protection scheme and specification for UCTs.

There are no performances target for reactors. The current average failure rate is seven in 12 years (3 per 5 yearly period).

Reactor failures are relatively rare. In general, proper inspection and maintenance can prevent major failures by timely corrective and preventative maintenance.

Figure 22 Reactor outage performance

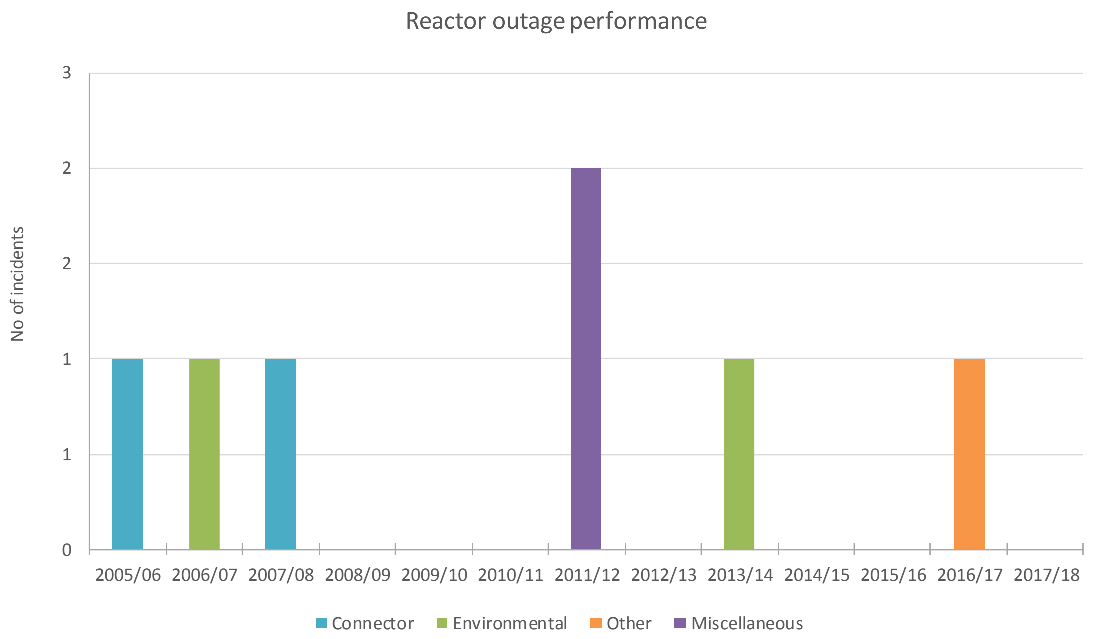
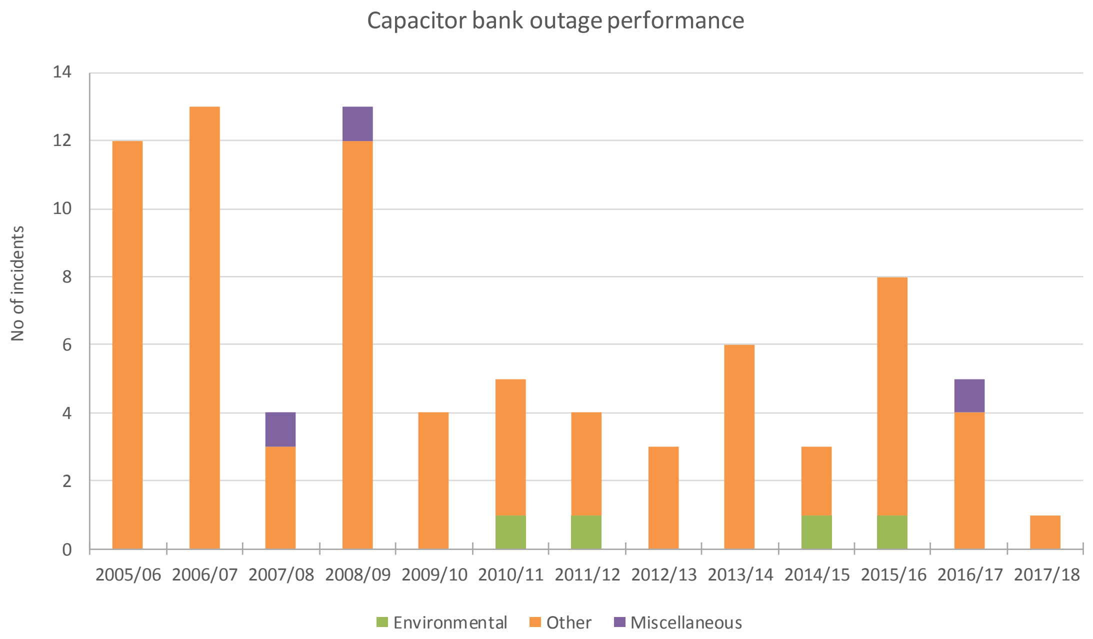


Figure 23 Capacitor bank outage performance



C.6.2 Asset Population

This asset class incorporates 57 Capacitor banks; 139 reactors; 8 Synchronous condensers (located at Haywards); 2 Synchronous condensers at Islington (which have been mothballed); 3 Static Var Compensators (SVCs); 4 STATic synchronous COMpensators (STATCOMs), including those located at the HVDC converter stations; and their associated control and protection systems, auxiliary systems, and primary assets. The breakdown of the reactive asset population is shown in Table 9 and Table 10.

Table 9 Reactive power asset population

Type	Quantity
Synchronous condensers	8
SVCs	3
STATCOMs	4
Capacitor banks	57
Reactors	139

Table 10 Capacitor bank and reactor population as at 02 March 2018

Type	220 kV	110 kV	66 kV	< 66 kV	Total
Capacitor banks	**13**	**13**	**4**	**27**	**57**
Reactors					
Shunt reactors	1	0	0	4	5
Part of Synchronous Condenser	0	0	0	4	4
Part of SVC	0	0	0	18	18
Part of STATCOM	0	0	0	23	23
Series reactors	1	0	0	14	15
Reactor part of capacitor banks	15	13	9	37	74
Reactors total	**17**	**13**	**9**	**100**	**139**

C.6.3 Asset Health and Condition Knowledge

Reactive power assets do not fit into Transpower's standard network asset criticality framework because their function serves regions rather than individual substations, circuits or branches.

Transpower plans to develop a criticality model for the reactive power assets that takes this into account and that provides information on which dynamic reactive power assets would have the greatest impacts if they failed. This will require system modelling of the current and future potential network requirements for reactive plant. This would be affected, for example, by potential changes in generation and load across New Zealand.

Transpower's current approach is to assess criticality of component equipment on a case-by-case basis as required, such as power electronics and control systems.

Transpower has also indicated that it is impractical to develop an accurate asset health model for capacitor banks at this stage, as historical accurate condition data for capacitor cans is not available. As this information becomes available and with monitoring of can failure rates, failure modes, age of the capacitor can population, and condition of the cans, a useful asset health model can be developed. In the interim Transpower will continue to use age and the probability of failure as a proxy for asset health.

Reactors are relatively simple asset and can be retained in service using routine and low cost maintenance interventions. The main causes of deterioration for reactors are corrosion, paint damage, insulation degradation, hot spots, vermin damage, and bird related damage. Most reactors are in good condition apart from minor issues such as paint damage.

Synchronous condensers, being rotating plant, require greater individual attention to the management of the assets then capacitors banks and reactors. These plants are managed as individual facilities and asset strategies are developed for each site. Major refurbishments on the synchronous condensers (SC1, 2, and SC7-10) were carried out in RCP 1 to extend their life expectancy. Improved online monitoring has been installed to indicate particular performance issues. The condition of the main machines are in an acceptable state. They can reliably operate until 2035 when another refurbishment is likely to be required.

SVC3 at Islington is the oldest SVC on the network and is currently in a poor state. A key issue with SVC 3 is obsolescence. There is no manufacturer support for the SVC3 control system and in general it is difficult to procure spares for SVC3. The cooling system is also in a poor state and the valves are of an older design which are not compatible with newer control systems. A major refurbishment is required to improve the condition of SVC3.

Since commissioning, SVC7 at Albany has experienced a high number of thyristor failures and some control system components are now becoming obsolete. A major refurbishment is required to address these issues as SVC7 is essential for voltage support in the upper North Island area. Apart from these failures, SVC9 at Islington is still in good condition with sufficient spares coverage and manufacturer support.

All STATCOMs are relatively new and in good condition. Apart from minor on-going concerns such as air conditioning unit failures and corrosion issues, the health of the overall installations is good. One major risk associated with STATCOMs is the Windows XP based control system, which is no longer supported by Microsoft. We have experienced a higher than normal failure rate of STATCOM power modules which is currently being resolved through the manufacturer.

A professional network with international peers helps Transpower sustain and build intellectual property about the procurement and lifetime management of reactive plant. Feedback and learning from international experience is essential to understanding developments in good industry practice. The international networks also assist to gain early warning of potential modes of failure in our equipment.

C.6.4 State of the Assets

Overall, Transpower's reactive assets are performing well. Ongoing refurbishment and replacement work is required to ensure that their performance meets future system requirements.

The life expectancy of the control and protection systems on synchronous condensers is around 20 years while many primary assets are expected to last over 40 years. Depending on the system need, the overall installations may have 'mid-life refurbishments' to extend their life to 40 years.

Table 11 Haywards synchronous condensers ages

Unit	Commissioned	In-service Age	Refurbished	Expected End of Life or Next Refurbishment
HAY C1 - C2	1962	56 years	2011/12	2035
HAY C3 - C4	1955	63 years	1989-92	2035
HAY C7 - C10	1965	53 years	2011-13	2035

Table 12 Capacitor bank and reactor life expectancy

Asset type	Expected Life	Comments
Capacitors	30+ years	Design life of capacitor cans is 25 years in service, as the capacitor banks are switched in according to system need; the actual life can be longer. However, many factors could reduce their life expectancy.
Reactors	40 years	Reactors over 25 years are assessed for refurbishment work such as painting to protect winding insulation to extend life expectancy

Life expectancy of capacitor cans are difficult to estimate as it is affected by many external factors such as the electrical stresses, operating temperature, quality of the original installation, etc. The probability of failure for capacitor cans does increase with age, but it is difficult to identify the failure point due to the random distribution of failures and lack of experience with capacitor banks operating beyond 30 years of age.

Reactors have long life expectancy, with minimal maintenance.

Table 13 SVC & STATCOM - age and life expectancy

Asset	Commissioned	In-service Age	Expected Life
Islington SVC3	1996	22 years	20 years
Albany SVC7	2008	10 years	20 years
Islington SVC9	2009	9 years	20 years
Kikiwa STATCOM	2010	8 years	20 years
Penrose STATCOM	2013	5 years	20 years
Marsden STATCOM	2013	5 years	20 years
Haywards STATCOM	2013	5 years	20 years

Figure 24 and Figure 25 show the age profiles for capacitor banks and reactors. The weighted average age for capacitor banks is 20 years and 17 years for reactors.

Figure 24 Capacitor bank population age profile

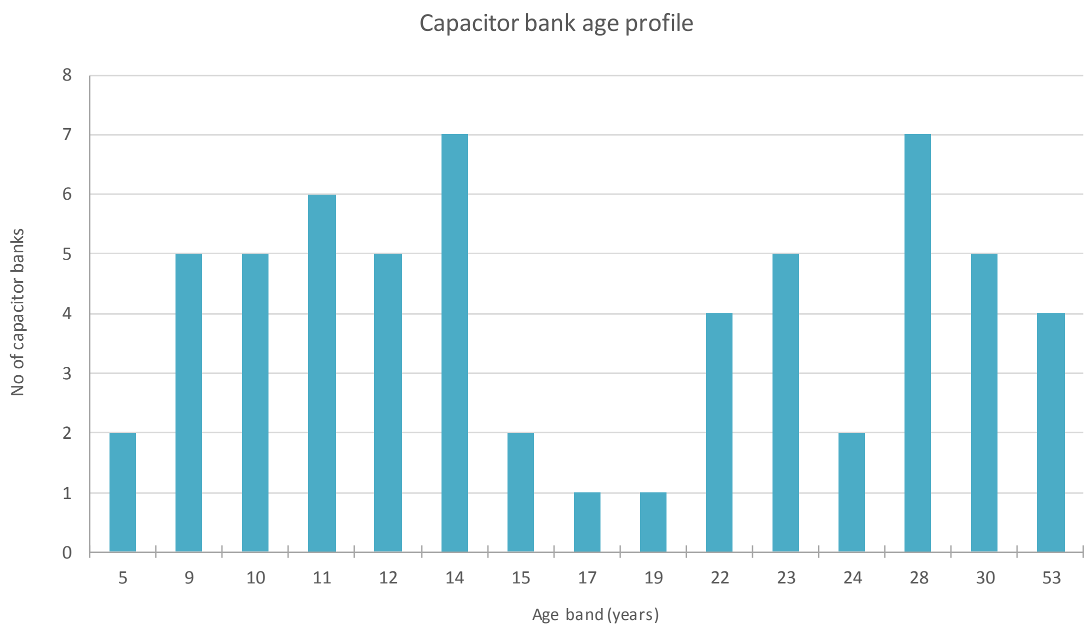
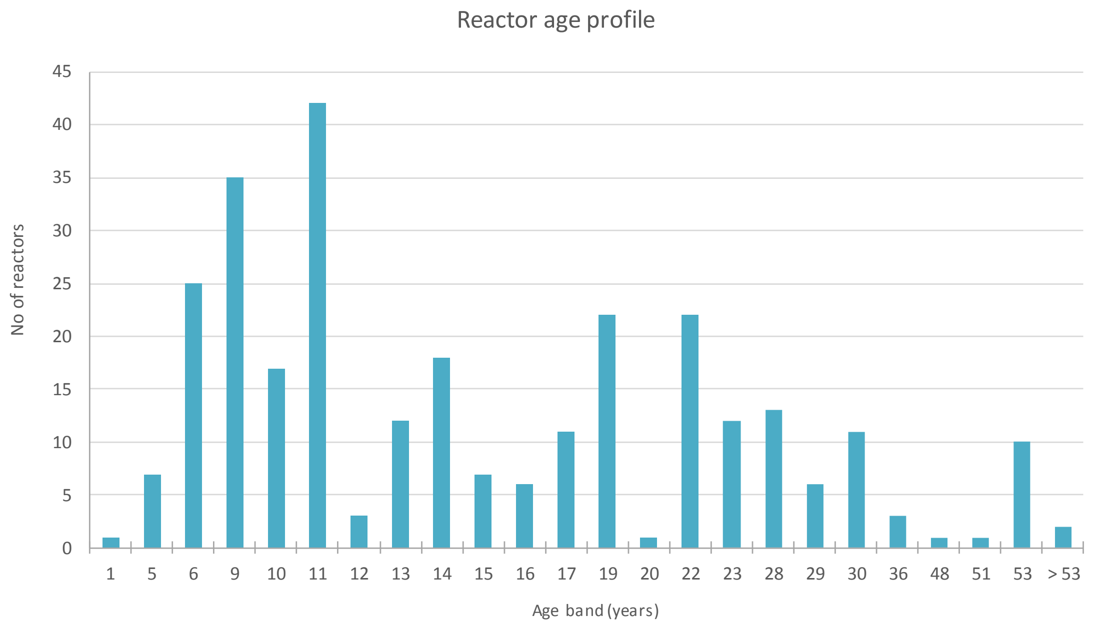


Figure 25 Reactor population age profile



C.7 SA Protection systems

C.7.1 Strategic Objectives, Measures and Performance

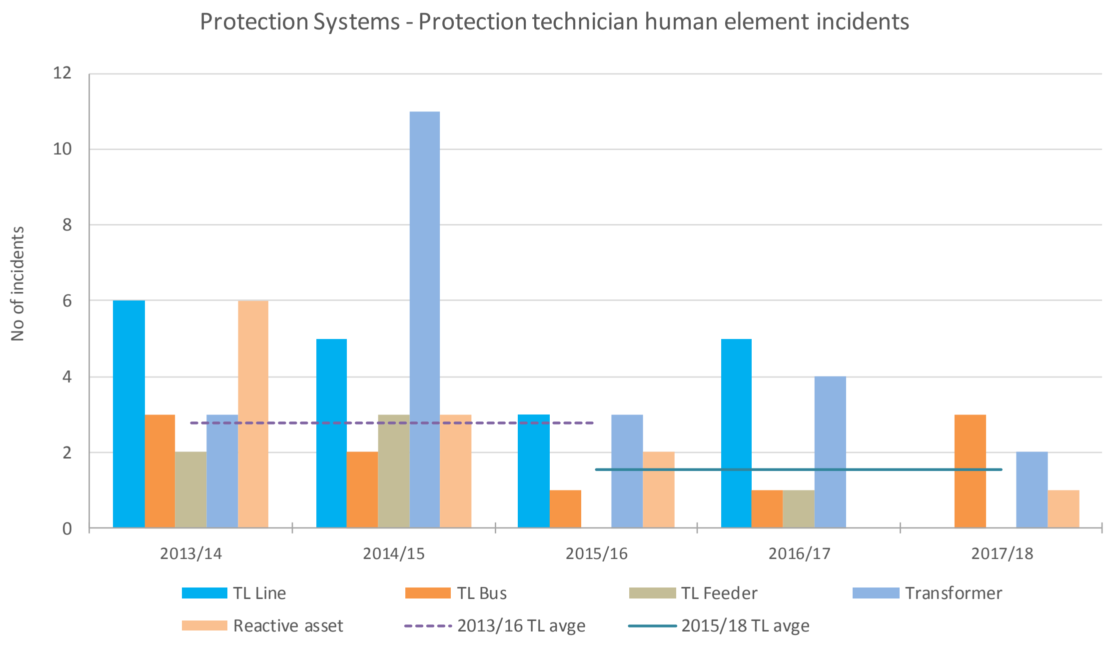
The overarching objective for the protection assets is that they operate safely and reliably, at least lifecycle cost. To achieve this the key objectives are:

- Safety: Minimise safety hazards during faults by having the whole transmission network covered by main and backup protection.
- Asset Performance:
  - Number of protection technician human error incidents resulting in unplanned outage to be less than 10 per annum on a 5-year rolling average. The current 5-year rolling average is 14 per annum and the current 3-year rolling average is 8.7 per annum
  - Achieve at least 98% correct operation for protection relays. No actual performance has been provided.
  - Failure rate of numerical relays to be less than 0.5% per annum on a five-year rolling average. Current rate is approximately 0.35% per annum
- Asset Performance: Zero instances of DC supply failures leading to interruption of supply. Experience is 1 failure in the last 5 years

- Asset Performance: Meet DC supply carryover requirements set out by System Operator
- Revenue metering fleet complies with the Electricity Industry Participation Code.

Figure 10 below indicates improvement in the number of HEI events.

Figure 26 SA Protection Systems incidents



C.7.2 Asset Population

Table 14 shows the population of the protection schemes, revenue meters and station DC systems.

Table 14 Protection, metering and DC system populations

Asset class	Asset type	Total
Protection	Bus Zone and Circuit Breaker Fail protection	163
	Bus Coupler protection	133
	Feeder protection	847
	Line protection	580
	Transformer protection	338
	Reactive Asset protection	67
	Special Protection Schemes (SPS)	27

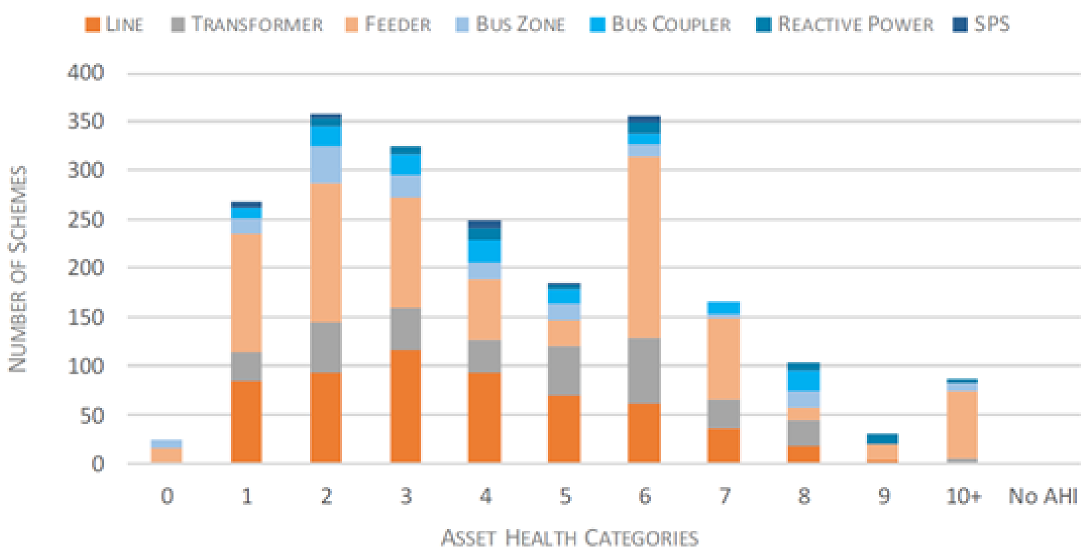
Asset class	Asset type	Total
	Arc flash protection	30
	Outdoor Junction Box (ODJB)	1,529
Metering	Revenue meters	478
Station DC Systems	Battery banks	330
	Battery chargers	333
	UPS batteries & systems for dynamic reactive assets and reactive power controllers	17

C.7.3 Asset Health and Condition Knowledge

Transpower is continuing to develop an asset health model and criticality framework for protection and station batteries investments. The intent is to continuing to evolve a risk-based framework and tools for evaluating protection systems and for adjusting the prioritisation of secondary system works. This will inform replacement timing and provide supporting information on which assets should receive additional protection and functionality, such as duplicated protection schemes.

Asset health establishes a base line comparison amongst all fleets. At this stage of development, for protection assets, an asset health index of 8 is equivalent to the replacement interval (20 to 25 years). Each asset is then allocated an index based on its current age versus its replacement interval. Figure 27 shows the protection fleet's asset health.

Figure 27 Protection fleet asset health



While the majority of the fleet is in good condition, Transpower is expecting a significant uplift in replacements in 5-10 years (i.e. due to the relatively large number of assets with the current asset health index of 6) and this reflects in the continued high expenditure in RCP4 and RCP5.

Transpower relies on spreadsheet-based data sets that contain lists of the assets under each portfolio and asset attributes like age, relay type, and whether protection is duplicated or not, to build a forecast of the required investment. Asset Health Models have been developed for protection schemes (excluding ODJBs) and station DC systems driven by the age of the assets which are included in the Decision Framework spreadsheets for each portfolio. There is no Asset Health Model for revenue metering.

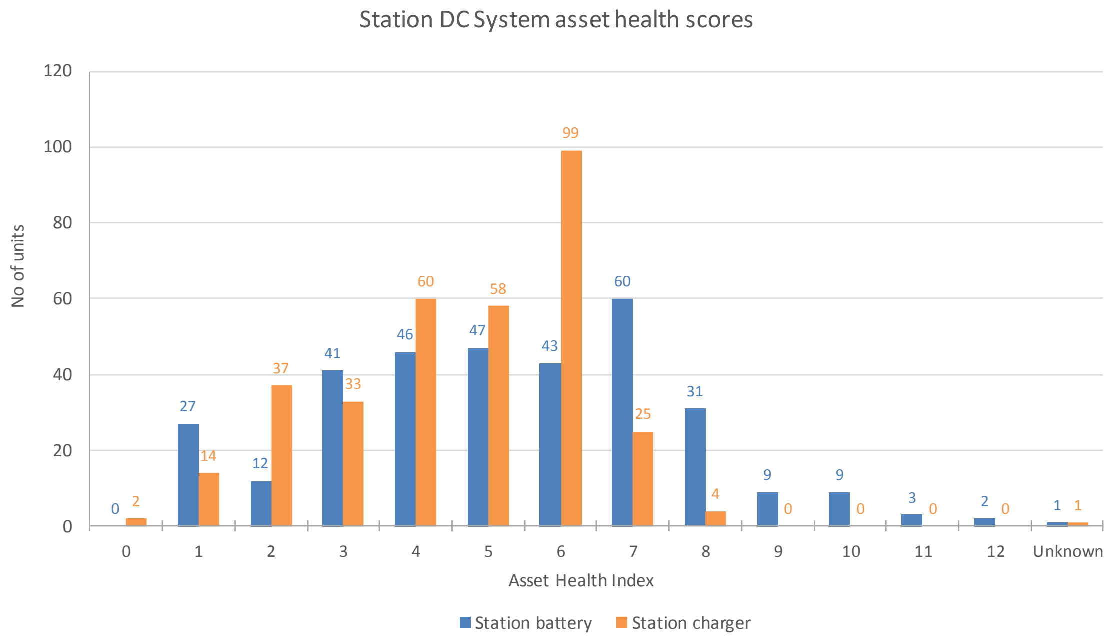
Condition assessments are carried out on the majority of the network protection assets so that any deteriorating assets are identified and scheduled for repair or replacement. Condition assessment of relays is generally a binary pass/fail assessment, with failure resulting in correction or replacement.

A recent nationwide condition assessment has shown that many of Transpower's older ODJBs have exposed live terminals, and do not meet current expectations for a safe working environment. Many are also vulnerable to rodent intrusion and damage. A small number of ODJBs show significant corrosion damage that may compromise future reliable service.

The majority of the ODJBs are in a good condition. Asbestos has been confirmed in approximately 40 of our ODJBs with an estimated 170 ODJBs predicted to contain asbestos. The replacement of our ODJBs are based on condition. Where ODJBs have asbestos, replacement is carried out at the same time as protection.

Figure 28 shows the asset health of Transpower's Station Batteries and Chargers. The station batteries beyond AHI8 are to be replaced by the end of RCP2.

Figure 28 Station DC System asset health



There is no AHI model for Revenue Metering. Replacements are age based and the population as a whole is generally in good condition but will be coming to the end of its life in RCP3.

C.7.4 State of the Assets

The state of the protection and battery asset portfolio typically are limited by the age of the assets compared with expected life. The life expectancies are:

- 15 to 25 years for numerical protection relay schemes;
- 35 to 40 years for electromechanical and static relay schemes;
- Microprocessor protection schemes sit in between these with a life expectancy of 20 to 25 years;
- Life expectancy is 8-12 years for station batteries and 20-30 years for station chargers; and
- The life expectancy for revenue meters is 12 years.

C.8 SA Substation Management Systems

C.8.1 Strategic Objectives, Measures and Performance

The key performance objectives are:

- Service Performance: Average of six or less RTU and SMS failures each year by 2020;
- Service Performance: 5-year rolling average of 30 or less I/O module failures by 2020;
- Safety: Increase remote plant status visibility for operators and field staff; and
- Service Performance: Reduce interruption duration times with use of remote access to engineering information, and reduce overall average network fault resolution time.

The reported failures are almost exclusively across the legacy fleet. There have been fewer than 10 failures of new Coopers' devices (including both SMPs and I/O modules) since 2012 when deployment commenced. Transpower expect the asset performance of the legacy RTU and I/O module fleet to decline sharply over the coming years but the overall performance should improve as more sites are upgraded to the new SMP solution. By the end of RCP3 Transpower expect to be meet the performance objectives.

Table 15 categorises the SMS asset level performance ratings by failure rate performance.

Table 15 SMS asset relative fleet performance ratings

Asset fleet health rating	Relative failure rate
Excellent	< 50% of allowable ACS rate
Good	50 - 80% of allowable ACS rate
Average	80 - 120% of allowable ACS rate
Poor	120 - 150% of allowable ACS rate
Very Poor	> 150% of allowable ACS rate

The current performance for component assets are:

- RTUs: Average with failure rate random and not showing signs of increasing;
- Legacy I/O Modules: Very poor;
- SMPs and SMP I/O Modules: Excellent as assets are relatively and installed since 2011;

- GPS Clocks: Average and generally managed to a design life of 15 years; and
- HMIs: Average in terms of failure rate performance and expected quickly worsen.

C.8.2 Asset Population

Table 16 shows the populations of the SMPs and RTUs. To date 34% of sites have been upgraded to SMP with a total of 30 sites (16%) currently being upgraded to the new SMP system. The remaining 50% of sites consist of the GE or Foxboro units that Transpower can no longer obtain and/or are unsupported.

Table 16 RTU & SMP device populations by type

Type	Age range	Units in service	No. of sites	Comments
SG-4250	< 2 years	18	12	2nd generation SMP (now commencing deployment)
SMP16	< 7 years	65	60	1st generation SMP
GE Harris D200	7 to 12 years	17	17	No longer supported & spares cannot be obtained (legacy units)
GE Harris D20VME	3 to 13 years	64	63	
GE Harris D20ME	4 to 14 years	12	10	No longer supported & Ethernet & spares cannot be obtained (legacy units)
GE Harris D20M++	8 to 18 years	20	16	
Foxboro C50	13 to 22 years	94	7	Legacy units

Table 17 shows a breakdown of the I/O modules by generation. About 40% of the fleet is now comprised of newer Coopers I/O modules. As the SMS programme progresses the legacy I/O modules are replaced but completion is unlikely before the end of RCP3. The largest group of I/O modules are Group 3 which were deployed pre-1995 and are 23 years or older.

Table 17 I/O modules by generation

Type	Age range	Units in service	No. of sites	Comments
Coopers I/O	< 7 years	705	92	Currently set of models
Legacy I/O (Group 1)	3 - 13 years	~ 68	16	Mostly newer sites & tactical upgrades (> 2005)
Legacy I/O (Group 2)	17 - 22 years	~ 246	30	Deployed 1996 - 2001
Legacy I/O (Group 3)	23 - 27 years	~ 712	61	Deployed < 1995

Table 18 shows the population of GPS clocks by capability. The serial clocks (38%) are still operationally viable but each clock will be replaced by a new PTP-capable clock as either programmed lifecycle replacement or as part of RTU replacement project (whichever occurs first).

Table 18 GPS clock by capability

Type	Units in service	Comments
Serial	71	Obsolete model
Ethernet capable	116	Deprecated model
Multi-LAN PTP capable	1	New model entered service in 2017

Table 19 shows the population of HMIs by type. The legacy HMIs will be replaced by the new Coopers Visual T&D solution as part of RTU replacement projects.

Table 19 HMI by type

Type	Units in Service	No. of sites	Comments
Realflex 6	9	9	Obsolete model (2012)
Survalent HMI	14	7	Deprecated model (2009 - 2012)
Coopers Visual T&D	27	21	New standard HMI (2012 - 2018)

C.8.3 Asset Health and Condition Knowledge

Transpower states there are no specific Asset Health Modelling and Criticality strategies for the SMS fleet and that asset age is a proxy for asset health for all SMS assets. However, with improving asset knowledge, Transpower will consider whether there are potential benefits to develop an asset health model.

Age of the assets is the primary driver for investment planning. Due to SMS consisting of modular electronic components there is no other meaningful way of determining the health of the units apart from relying on manufacturer recommendations, measured Mean Time Between Failures (MTBF) statistics, and real-world failure rates (both Transpower's own and other comparable customers).

Individual asset health ratings are based on the age of the specific asset (relative to its target replacement age), though this rating may be revised downwards if the asset is no longer fit-for purpose.

Table 20 is the current approach to indicating asset health with respect to excepted life of the asset fleet.

Table 20 Relative asset health ratings

Asset health rating	% of Useful Life consumed
Excellent	< 33%
Good	33 66 %
Average	66 - 100%
Poor	100 - 120%
Very Poor	> 120%

Special attention is also be given to the functional expected life of a device and infrastructure and support tools that underpin it, as these are increasingly susceptible to technological obsolescence. Such factors are playing an increasingly significant role in lifecycle management decisions as the pace of technology development accelerates.

Table 21 shows the expected life durations for SMS assets as defined in the ACS.

Table 21 SMS asset expected life

Asset fleet	Expected life
Legacy RTUs	15 years
Legacy I/O modules	15 years
Coopers SMP	15 years
Coopers I/O modules	25 years
Coopers HMI	5 years
GPS clocks	15 years

C.8.4 State of the Assets

Figure 29 shows the state of the assets by the breakdowns for each asset fleet.

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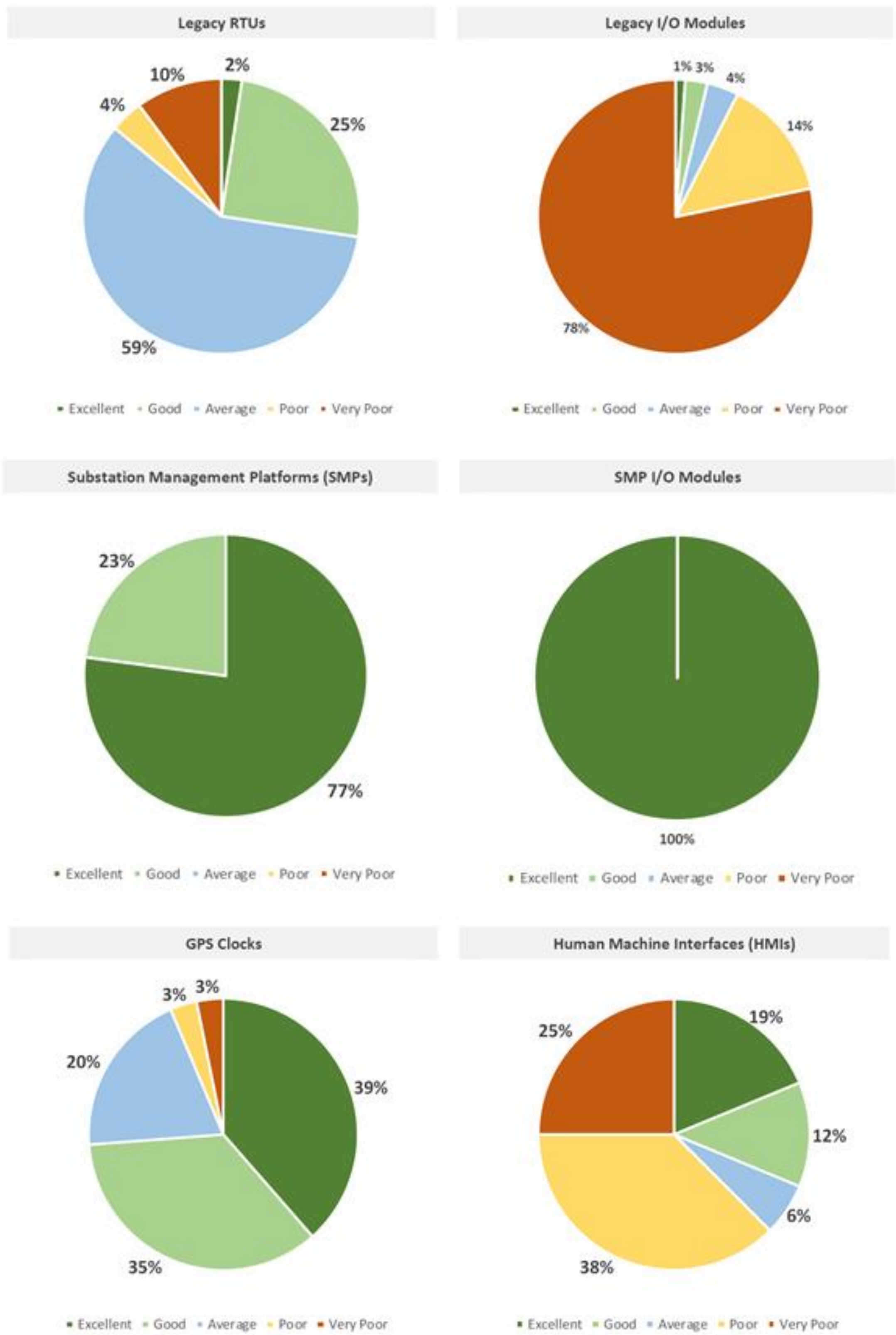
Figure 29 SMA asset fleet assessed condition



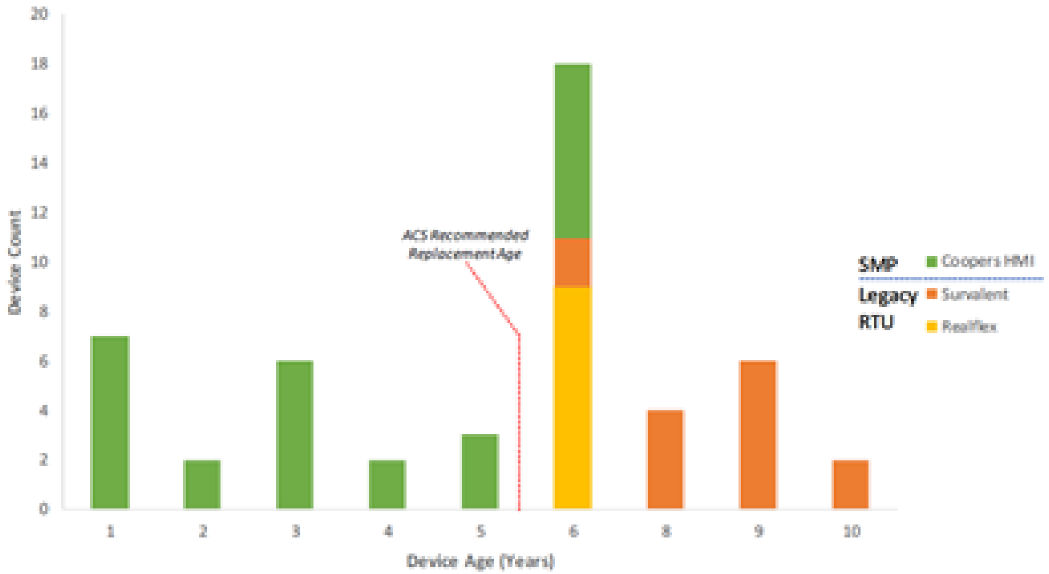
The graphs indicate the new SMP and SMP I/O module fleets are in the best overall condition, as expected as these fleets are new and have a relatively long life expectancy.

The legacy I/O module fleet is in the poorest condition with more than 90% of the fleet being classed as being in poor, or very poor, health. The legacy RTU fleets are in reasonable overall health.

GPS clock fleets are in reasonable overall health with only a small subset of the assets falling into the poor and very poor health. Transpower state that the majority of the older clocks (those exceeding 15 years of age) are currently in the process of being replaced, or are at sites subject to divestment/decommissioning.

The HMIs are a source of increasing concern with over 60% of the assets classed as poor or very poor health; the transition from good health to poor health happens quickly for this fleet as the HMIs are relatively short lived. Figure 10 indicates that age related factors are causing the main concerns with HMIs with legacy systems. The Asset Class Strategy states a target replacement age of 5 years for HMIs reflecting the measured failure rates which suggest that the current age is likely to be problematic.

Figure 30 HMI age profile



C.9 E&D capex

Table 24 (refer page 53) shows the full list of potential E&D projects Transpower has identified for RCP3, classified by the assessed likelihood of the project proceeding during the regulatory period. This list collates the E&D project information used in generating the expenditure forecast based on a two-scenario approach, related information from the Transmission Planning Report that summarises the network constraints and the current level of assessment applied to the preferred solution.

Whilst Table 24 shows discrete projects, Transpower adopted a high and low scenario approach in generating a forecast expenditure considered to represent a P50[6] forecast that would be sufficient to address the uncertainties inherent in the E&D programme. By generating the forecast with consideration of the uncertainty associated with E&D projects that are often in response to changing network conditions due to changes in customer requirements or loads for new commercial or industrial developments, the forecast should allow Transpower to re-prioritise and complete work as required.

The Decision Framework is a crucial stage in assessing the priority of work, and includes the assessment of options for a preferred solution.

Table 22 shows a description of the Options Assessment Approach (OAA) levels.

Table 22 OAA level classifications

OAA level	Description	Investigation parameters
None	None	Problem or opportunity has been identified but not yet assessed Costing information is based on judgement and expertise
L1	1	Asset class strategy prescribes preferred investment solution No options assessment is undertaken
L2p	2 - Planning	Investigations with low complexity and/or cost, required within 10 years Preferred solution informs plan Investigation revisited before any expenditure
L2d	2 - Delivery	Investigations with low complexity and/or cost for delivery Preferred solution is delivered
L3p	3 - Planning	Investigations with: * medium complexity and/or cost, required within 10 years * high complexity and medium cost, required after 10 years Preferred solutions informs plan Investigation revisited before any expenditure

6 This relates to the statistical confidence level for an estimate or forecast. In this instance, P50 is defined as the forecast value with 50% probability that total expenditure shall exceed the forecast, and by definition 50% chance that total spend will be below forecast

OAA level	Description	Investigation parameters
L3d	3 - Delivery	Investigations with: * medium complexity and/or cost, required for delivery * high complexity and medium cost, required for delivery Preferred solutions is delivered
L4p	4 - Planning	Investigations with: * high complexity and cost, required within 10 years Preferred solution informs plan Investigation revisited before any expenditure
L4d	4 - Delivery	Investigations with: * high complexity and cost (< $20 million), required for delivery Preferred solution is delivered
L5d	5 - Delivery	Investigations with preferred solution expected to cost > $20 million requiring full consultation with stakeholders and individual approval by Commerce Commission

For the potential E&D projects shown in Table 24 (over page), external triggers for projects are shown in red whilst projects with an assessed Grid Need date of 2020 or earlier are shaded. Table 23 shows the definition of the likelihood classifications Transpower has applied to the projects.

Table 23 E&D projects likelihood classifications

Likelihood	Solution	OAA progress	Confidence in external drivers	Confidence in generation / load changes	Approval level
Extremely Likely	Design phase	Expected	High confidence in well-defined external drivers	Expect generation / load changes will happen	Expected to pass all gates
Highly Likely	Credible solution	Expected	Lower confidence in external drivers	Less certain about generation / load changes	Pass early gates
Likely	High-level only	None	Scope of need uncertain	No confidence in project proceeding	None - order of magnitude estimates only

Table 24 E&D forecast expenditure for RCP3 (real in $2017/18 million)

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Extremely Likely	National	Statutory	Corridor Management Programme	-	Transpower seeking provisions within Resource Management Act 1991 to enable ongoing use, upgrade & future protection of Transpower assets from inappropriate development & land use under existing lines & adjacent to substations. Construction capex influenced by compliance with any revised requirements of Ministry for Environment *National Policy Statement on Electricity Transmission* following current review and any reforms in Resource Management Act 1991.	Compliance	-	-	-	$5.13	$ -	$5.13
Extremely Likely	North Island	Auckland	Bombay (BOB) 220/110 kV interconnection transformer	8.4.2.3	During low generation in Waikato 110 kV system, power flows can exceed N-1 capacity of Otahuhu - Wiri section. Transpower implemented variable line rating on Otahuhu - Wiri Tee sections in 2015 to defer major investment. From summer 2018, other issues will constrain capacity & condition assessments show intervention needed by 2023. All leading options to address constraint & condition issues involves additional transformers as Bombay.	Load growth	2022	L4p	Yes	$0.15	$8.79	$8.94
Extremely Likely	North Island	Auckland	Bussing Arapuni (ARA) - Bombay (BOB) circuit at Hamilton (HAM)	8.4.2.3	Relieve transmission constraints on Waikato & Central North Island 110 kV systems	Transmission constraint	2025	L5p	-	$ 0.13	$1.59	$1.72

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Extremely Likely	North Island	Auckland	2nd Bombay (BOB) interconnection transformer	8.4.2.3	Deteriorating condition of 110 kV Bombay - Hamilton & Bombay - Otahuhu circuits. More economic to install 2nd interconnection transformer than refurbish 110 kV BOB - HAM line. All 110 kV BOB - HAM major life extension work cancelled; expected to remain in-service until 2030 then install 2nd transformer & dismantle lines. Needed to relieve transmission constraints on Waikato & Central North Island 110 kV systems.	Asset condition	2022	L4p	-	$0.13	$5.00	$5.13
Extremely Likely	South Island	South Canterbury	Poor restoration time at Studholme	18.4.2.1	Investigate options to reduce system restoration times at Studholme following an outage of Studholme – Timaru circuit which will improve reliability at Studholme if & when Glenavy – Studholme permanent system split is implemented.	Load growth	2022	-	-	$0.05	$0.50	$0.55
Extremely Likely	North Island	Waikato	Permanently split Arapuni (ARA) bus	9.4.2.1	Number of external factors contribute to overloading of existing ARA - HAM circuits. Reconductoring 110 kV ARA - HAM circuits not economically justifiable. Existing bus split at ARA done as short-term measure in 2011; additional regional geothermal generation, decommissioning of Auckland thermal generation & load growth in Auckland requires bus split to be permanent. Requires reconfiguring of 110 kV bus as a standard configuration.	Transmission constraint	2018	L3p	-	$0.05	$1.50	$1.55

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Extremely Likely	North Island	Waikato	Hangatiki (HTI) voltage constraints	9.4.2.5	Existing load constraints on Waikato 110 kV network, The Lines Company forecasting additional 56 MW load in stages over 2018-21. Load growth in regional diary industry. Currently high reactive power consumption at Hangatiki due to high load & low load power factor on transformers. Project requires installation of two 15 MVAr capacitor banks at Te Awamutu 110 kV bus	Load growth	2021	L3p	-	$0.02	$3.20	$3.25
Extremely Likely	South Island	South Canterbury	Waikati Valley load control	18.4.2.1	Options to be discussed with Network Waitaki. May include special protection scheme to allow additional load on network, upgrading existing circuits, new grid exit point or shifting load. Medium to long term solution to be developed with Alpine Energy including new 220 kV grid exit point near Waihao (which would be customer initiated - based on investment decisions of local irrigation & dairy companies).	Load growth	-	None	-	$0.06	$2.30	$2.36
Highly Likely	National	Grid backbone	Investigate HVDC black start possibility after an "island black" event	-	Not covered by TPR	System security	-	-	-	$0.08	$4.50	$4.58

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	National	Grid backbone	Generation connection driven grid investments	6.3.2.2	Wairakei Ring connects generation on central North Island to load centres of Upper North island, Waikato & Bay of Plenty via two 220 kV transmission lines. During very high generation, capacity of circuits causes transmission constraint. TPR signals known transmission constraint issues if generation locates in number of regions including Wairakei Ring, Kaweru or Edgecumbe. Generation not expected to connect in all these locations during RCP3, therefore included indicative amount of generation driven investment needs. Grid need is uncertain & dependent on Wairakei area generation development timing.	Transmission constraint	-	None	-	$0.10	$12.10	$12.20

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	National	Grid backbone	Huntly - Stratford transmission constraint	6.3.2.3	During high generation Taranaki region, 220 kV Huntly - Stratford circuit constrains generation export. Identified incremental enhancements: a) install series reactor & special protection scheme on 110 kV Bunnythorpe - Mataroa circuit to reduce power flow; b) upgrade protection on Huntly - Stratford circuit, depending upon generation development in Taranaki region; c) investigate possible variable line ratings on 220 kV Tokaanu - Whakamaru circuits to address transmission constaints. Significant investment in generation in the Taranaki or Wellington regions or increase in HVDC north transfer will trigger possible major investments in transmission circuit thermal upgrades, reconductoring or new transmission lines (which will likely be in excess of Major Project threshold).	Transmission constraint	2022	None	-	$0.05	$2.00	$2.05
Highly Likely	National	Grid backbone	Waikato & Upper North Island (WUNI) High Voltage management	6.3.2.4	Small loads cause voltage control issues in WUNI, which are currently addressed by HV line switching. Concern that switching may cause security of supply issues. Possible solution is installation of shunt reactor to increase grid capability to absorb reactive power during small load periods. Other alternatives to be investigated such as switching additional circuits out of service or seeking voltage support contracts.	Voltage	2021	None	-	$0.10	$5.86	$5.96

Synergies ECONOMIC CONSULTING

GHD Advisory

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	National	Grid backbone	Benmore (BEN) - Roxburgh (ROX) transmission capacity	6.6.2.2	Most of hydro generation in region consumed locally by Tiwai Point aluminium smelter with other major load centres including Dunedin & Invercargill. Region highly susceptible to local hydrology. Clutha - Upper Waitaki Lines Project (CUWLP) approved suite of projects to increase transmission capacity between Clutha & Waitaki Valley. 2nd tranche includes series reactor for Naseby - Roxburgh line coupled with Cromwell - Twizel thermal upgrade depending upon significant increase in generation or reduction in load in region.	Transmission constraint	2020	None	-	$0.10	$10.00	$10.10
Highly Likely	National	Grid backbone	Aviemore - Benmore (BEN) transmission capacity	6.6.2.2	Most of hydro generation in region consumed locally by Tiwai Point aluminium smelter with other major load centres including Dunedin & Invercargill. Region highly susceptible to local hydrology. Clutha - Upper Waitaki Lines Project (CUWLP) approved suite of projects to increase transmission capacity between Clutha & Waitaki Valley. 2nd tranche includes special protection scheme for Aviemore - Benmore line depending upon significant increase in generation or reduction in load in region.	Transmission constraint	2020	None	-	$0.05	$0.60	$0.65

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	North Island	Auckland	Wiri - Wiri Tee capacity	8.4.2.10	Peak load at Wiri forecast to exceed N-1 transformer capacity by 2022 & winter capacity of Wiri - Wiri Tee section from 2018. Can be managed operationally in short term. Short term options to be investigated to relieve transformer capacity issue. Long term circuit issue may be resolved by replacing line conductor. Complication in construction as line crosses motorway.	Load growth	2019	None	-	$0.06	$2.50	$2.56
Highly Likely	North Island	Waikato	Arapuni (ARA) - Kinleith - Tarukenga transmission capacity	9.4.2.2	Capacity of Arapuni - Kinleith - Tarukenga circuits to supply connected loads limited by N-1 capacity of line section connecting Lichfield substation. Local generation at Arapuni & Kinleith critical to maintaining security of supply. Severely limited capacity for additional load growth on Arapuni - Kinleith - Tarukenga circuits. Timing of project dependent on load growth at Kinleith & Lichfield. Options to be investigated to meet future demand if/when step increase in load, although reconductoring circuits will be uneconomic based on past analysis. Small thermal capacity upgrade on part of a section may be justified.	Transmission constraint	?	None	-	$0.10	$0.50	$0.60
Highly Likely	South Island	Canterbury	Islington spare transformer switchgear	-	-	Security of supply	-	-	Yes	$0.05	$1.00	$1.05

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	South Island	Canterbury	Hororata (HOR) & Kimberley voltage quality & transmission capacity	17.4.2.3	Short-term solution relies on existing automatic voltage load shedding scheme at Hororata to manage voltage quality (post contingency) at Hororata & Kimberley substations. Medium term solution (within 5-7 years) involves installation of three banks of 9 MVAr capacitor banks at Hororata. Timing dependent on feedback from Orion & possible increases in dairy & irrigation loads in area.	Voltage	2023	L2p	Yes	$0.05	$4.12	$4.17
Highly Likely	South Island	South Canterbury	Timaru region thermal capacity & voltage stability	18.4.2.2	Timaru area load forecast to exceed voltage stability limit by 2021. Other constraints in region to be resolved before Timaru load can exceed this limit. Timing dependent on resolving constraints with Studholme supply transformer & Temuka supply transformer & transmission constraint. Options include installation of shunt capacitors on Timaru 110 kV bus.	Load growth	2021	None	-	$0.20	$3.00	$3.20

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Highly Likely	South Island	South Canterbury	Timaru (TIM) 110 kV bus security & voltage collapse	18.4.2.3	Fault on Timaru 110 kV bus section will cause several network outages and issues, with a fault on zone C being the most significant by disconnecting neighbouring areas and causing voltage collapse in the Timaru, Ashburton and upper South Island areas. High-level options include reconfiguring Timaru 110 kV bus & install shunt capacitors have been identified for Timaru voltage support. No plans to investigate improved security of supply options as customers connected to single circuit line & Alpine Energy and Genesis have not requested a higher level of security.	System security	2022	None	-	$0.05	$2.00	$ 2.05

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Likely	North Island	Bay of Plenty	Kawerau (KAW) 110 kV ring bus	10.4.2.1 10.5.4.1 10.5.5.4	Generation export constraints exist for Kaweru 110 kV bus under high generation / low demand conditions. Transpower economic analysis suggests that risk of Kaweru transformer outage is low & with typical levels of generation & loads, special protection scheme will not operate. Kaweru T13 transformer due to risk-based condition replacement in 2019. Discussed options with stakeholders. If new generation proposals confirmed in Kawerau area, investment options will be investigated to address generation export constraints. Long-term solutions may address 110 kV & 220 kV transformer capacities through replacement and increasing thermal ratings of circuits, depending upon new generation proposals in Kaweru area.	Transmission constraint	2019	None	-	$0.10	$0.70	$0.80
Likely	North Island	Auckland	Mount Roskill (ROS) 110 kV bus upgrade	8.4.2.4	Peak load forecast to exceed N-1 capacity of existing supply transformers in ROS substation from 2024. Trip on existing single bus section at ROS causes loss of supply on ROS 22 kV & 110 kV loads. Preferred option to upgrade ROS 110 kV bus to three sections.	Security of supply	2021	L3p	Yes	$ -	$4.60	$4.60

Likelihood	Location	Region	Project	2018 TPR	2018 TPR trigger events	Primary driver	Grid need date	OAA level	Deferred from RCP2	RCP3 forecast ($ million)		
										Investigate	Construct	Total
Likely	North Island	Auckland	Wellsford supply security	7.4.2.1	Peak load at Wellsford forecast to exceed N-1 capacity of supply transformers from 2019. Short term solution managed operationally within Vector network. Transpower to replace bushings of existing transformer to extend service life. Long term solution includes customer investment in installing larger transformers at Wellsford & Transpower upgrade of protection schemes & potential switchgear upgrade	Load growth	2024	None	-	$0.30	$4.00	$4.30
Likely	North Island	Auckland	Henderson-Wellsford transmission capacity constraints	7.4.2.2	Outage on nearby circuit will cause Henderson - Wellsford section to exceed winter rating from 2025. Commissioning of new generation at Ngawha will help to defer issue towards end of forecast period. To reduce reliance on new generation, special protection scheme to be installed on HEN-WEL-MTO-MPE circuits.	Load growth	2025	None	-	$0.10	$ 0.50	$0.60
Likely	South Island	South Canterbury	Black Point (BPT) single supply security	18.4.2.4	Fault on either 110 kV Oamaru - Black Point - Waitaki circuit or Waitaki 220/110 kV interconnection transformer will disconnect Black Point load. Existing configuration is issue for planning maintenance outages on line or transformer. Possible solution may involve closing bus-tie on Oamaru 110 kV bus with further investigation required.	Security of supply	2019	None	-	$ -	$0.30	$ 0.30
TOTAL										**$7.23**	**$81.15**	**$88.38**

C.9.1 E&D project business cases

Upon request, Transpower provided Project Summary documents (together with business cases for the Extremely Likely projects) for the following:

Extremely Likely:	Bombay 220 kV interconnection transformer Hangatiki voltage constraints
Highly Likely:	Benmore - Roxburgh transmission capacity
Likely:	Kawerau ring bus Black Point single supply security

These documents illustrate the level of assessment of preferred solutions that has currently been done for E&D projects with different likelihood classifications. At the time of this independent verification, the Transmission Planning Report 2018 had not been published.

Bombay 220 kV interconnection transformer

TPR 2017 indicated:

- the system need was primarily related to transmission constraints between Otahuhu and Bombay;
- the most likely solution was a single interconnecting transformer in early RCP3 with a second interconnecting transformer installed later in RCP3;
- the 110 kV lines connecting Bombay to the Waikato region would be considered for dismantling after installation of the second interconnecting transformer at Bombay; and
- the interconnection of the 220 kV and 110 kV networks removed the need to replace the Otahuhu interconnecting transformer T4.

The system need for this project has become more complex since the TPR 2017 studies were completed:

- transmission constraints remain between Bombay and Otahuhu;
- asset health of the circuits between Otahuhu and Bombay now indicate end-of-life in early RCP3;
- if the Bombay to Otahuhu circuits, or part circuits, are dismantled, there is a need to replace Otahuhu interconnecting transformer T4 with a higher impedance unit so it can operate in parallel with other Auckland interconnectors. Otahuhu T4 has

poor asset health and would be a good candidate for accelerated replacement rather than major refurbishment;

- New Zealand Transport Authority (NZTA) has commenced planning to widen the motorway south of Auckland, impacting the tower assets on the Bombay to Otahuhu circuits;
- Auckland Unitary plan signals strong residential and commercial/industrial growth in the Bombay and Drury regions; and
- Counties Power have elected to continue investigating development of a Grid Exit Point (GXP) at Drury switching station. However, load growth increases show this does not negate the need to provide more capacity through interconnection at Bombay.

The drivers for the project are more complex and intertwined than the initial project envisaged, with no driver being more influential than another. For example, if the transmission constraint didn't exist, or the timing changed, Transpower expects to continue progressing an interconnection at Bombay as it provides a preferred solution to the conductor condition need and the stakeholder need to move assets for motorway development. Similarly, high Auckland growth is reflected by strong demand forecasts in the region. Counties Power's development of a GXP at Drury no longer significantly defers the need to interconnect at Bombay. The use of variable line rating (VLR) in 2015 has already significantly deferred the need for investment. Current forecasts show the issue may reappear in summer 2018. Transpower plans to use demand response to manage constraints until transformers can be installed and commissioned at Bombay.

TPR 2017 indicated an expected cost of approximately $15 million to install the first interconnecting transformer at Bombay. TPR 2018 indicates approximately $18 million is required for two interconnecting transformers. This change reflects an evolution in design and substation layout to remove costs and reconfigure the 110 kV bus at Bombay to better utilize the space.

The options for a regional solution are still being studied; however, all the short list options have a common component - to install two interconnecting transformers at Bombay at the same time.

This work has reached Capex Investigation, with designs and detailed costs for two 220/110 kV interconnecting transformers being progressed. A significant portion of capex costs are expected to be spent in RCP2 and with the balance in RCP3.

Hangatiki voltage constraints

The driver of this issue is load growth, primarily from industrial processing: iron sands mining and dairy processing. Due to the configuration of the grid in this region, load type and size, and the loading of assets, the additional load growth will cause low voltage constraints at the Hangatiki GXP.

The customer previously indicated they expected step load increases during RCP2. The industrial/commercial developments causing these changes have been delayed.

The project has completed the Opex Investigation phase and identified a preferred solution. The Initial Business Case to approve a Capex Investigation is currently being drafted. It is due to be circulated for sign off before the end of June 2018.

Transpower is confident the load growth will eventuate. Both commercial developments are progressing their investments, just more slowly than our customer initially anticipated. Transpower has advised they will monitor load growth developments and will assess the best timing for construction and commissioning on the works during the RCP3 period based on timing of the load increases.

Benmore - Roxburgh transmission capacity

The system need for this issue is the capacity of the circuits between Benmore and Roxburgh. These circuits impose a transmission constraint on north (export) and south (import) power flow between the lower South Island and Waitaki Valley. With high power transfers between Benmore and Roxburgh, an outage of a Clyde–Cromwell–Twizel or a Clyde–Roxburgh circuit leads to overloading of the Livingston–Naseby or Naseby–Roxburgh circuits.

The investment justification for this system need is based on the cost of constrained generation dispatch rather than system security or reliability. A significant amount of analysis has already been completed to identify if the issue should be progressed to the Decision Framework.

The decision to progress the investigation through to the first stage of the Decision Framework is based on the likelihood of economic analysis showing a positive net market benefit. This requires an in-depth level of analysis to make a judgement on progressing the investigation. The work undertaken to date is not complete but Transpower is confident there is reason to look more closely at the issue and options.

The prior studies and analysis will be used to inform the forthcoming Opex Investigation with an expectation the project will progress quickly to Capex Investigation.

TPR 2018 indicates the preferred solution to be approximately $10 million compared with the previous estimate of $7 million in TPR 2017. This is based on updated information received in the last 12 months from the Tactical Engineering teams related to asset and construction costs.

The system need has been registered in FMIS via a Needs Registration with an Opex Investigation scheduled for late 2018. The Investigation Approval Business Case will be completed at the beginning of the Opex Investigation.

Kawerau ring bus

The outage of a Kawerau 110 kV bus section disconnects several circuits, transformers and generators. A significant proportion of the generation connected to the 110 kV bus is constrained back, or off, during a bus section outage. In addition, some bus maintenance outages at the Kawerau 110 kV bus split the 110 kV bus with both sides of the split tied through the 11 kV network owned by Norske-Skog. This is a particularly difficult outage to arrange and for the System Operator to manage.

As more generation connects to the 110 kV bus the system and market impact of generation constraint during bus section outages increases. The region has significant geothermal generation resource; Transpower is aware of several potential new generation developments, or expansions of existing generation, and anticipate further generation development in the region is likely within the RCP3 period.

This issue was investigated, and options studied, as part of the Kawerau 110 kV switchgear and 110/11 kV transformer replacement project in RCP2. The ring bus was not progressed at that time due to lack of economic justification. Further generation development is expected to change this outcome. The previous analysis has already narrowed down the options to a preferred solution.

The project has been entered into FMIS. Further generation developments, and or increasing complexity of managing outages, will drive a review of the work done to date and likely progression of an Initial Business Case for Capex Investigation approval.

Transpower expects that this project will progress straight to Capex Investigation should future economic analysis related to economic analysis and outage management show the project to be justified.

Black Point single supply security

This system need is driven by the grid configuration at Black Point (single point of connection) causing difficulties in planning outages for the connected circuit and associated interconnecting transformer.

This is an emerging issue. As load increases in the region arranging outages and load management becomes more complex and inconveniences more connected load. To progress an investment we must show the benefits outweigh the costs. Transpower anticipates the load growth to support further investigation into this issue towards the end of RCP2. Transpower is currently working in collaboration with Network Waitaki to develop a regional development plan, which will form an input to the decision-making process for this project.

The project has been entered into FMIS with a more detailed Needs Registration due to be completed at the conclusion of the regional development plan and further customer discussions.

C.10 ICT

Transmission Systems

The Transpower Transmission Systems enable real-time operation of the national grid, and daily operations and maintenance activities to ensure transmission system performance and reliability. Table 25 shows seven functional business themes.

Table 25 Transmission Systems business areas

Business theme	Description
Central Control	Real-time control of grid assets and wider situational information to manage risks and ensure security of supply
Field mobility & control	Capabilities and services to enable Transpower & service provider field staff to communicate and share information, to improve co-ordination and reduce operational risk
Outage planning & switch management	Systems to optimise grid outages to maximise service availability during planned grid works
Time series & plant information management	Integration, management, reporting of grid asset and service performance time-series data
Grid operations	Capabilities to operate assets to meet network, operational and asset performance requirements considering asset reliability, cost, safety and environment
Network & telemetry data management	Support effective and efficient modelling, configuration and management of grid telemetry information
Power systems engineering	Power systems design process, simulation and testing

Key systems reaching end-of-life and requiring replacement due to obsolescence and/or vendor support no longer being available are:

- SCADA/EMS
- Situational Distance to Fault (SDTF)

- Power Factory

The key trends that are likely to influence the Transmission Systems portfolio are:

- Everything as a Service (XaaS) - systems due for replacement are considered to be moved to a Software as a Service (SaaS) cloud delivered service where cost effective and minimises system customisations
- Big Data & Advanced Analytics - as systems improve and become more integrated, additional data will be gathered to support advanced analytics to drive business operations and performance improvement
- Industrial Internet of Things (IIOT) - technology to improve near real-time condition and operational awareness of assets to improve planning, delivery and operational capabilities
- Intelligent Systems - emerging technologies in machine intelligence that may impact planning and maintenance activities
- Industrial digital platform driving Next Generation critical systems - technology platforms that support developing and operating Industrial Internet applications to have a standardised approach to model and control, such as integrating SCADA and operational switch management (OSM)

C.11 ACS Buildings and Grounds

Transpower has identified that two key drivers for the RCP3 forecast capex are fences and roofs. These are considered the two most critical components to the integrity and security of the AC substations, and their overall condition is measured periodically over a three-year period to determine their asset condition.

Table 26 shows the scoring system for condition assessment using the standard SPM Assets methodology.

Table 26 Standard SPM Assets condition scoring system

Condition score	Description	% Asset Life assessed remaining
C1	Very Good	55 - 100%
C2	Good	37 - 54%
C3	Moderate	25 - 36%
C4	Poor	11 - 24%
C5	Very Poor	0 - 10%

Figure 31 shows the age profile for all substation fencing, including outdoor switchyard (ODS), security, power, perimeter and stock fences.

Figure 31 Substation fence age profile

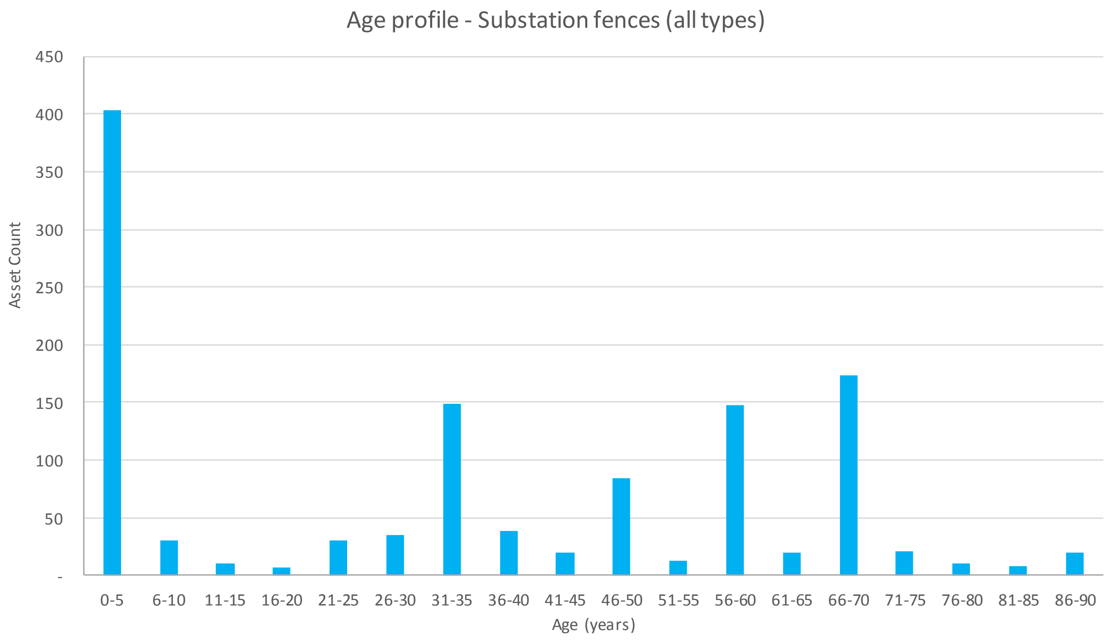


Table 27 lists the standard asset life applied by Transpower to the various fence types used in AC substations.

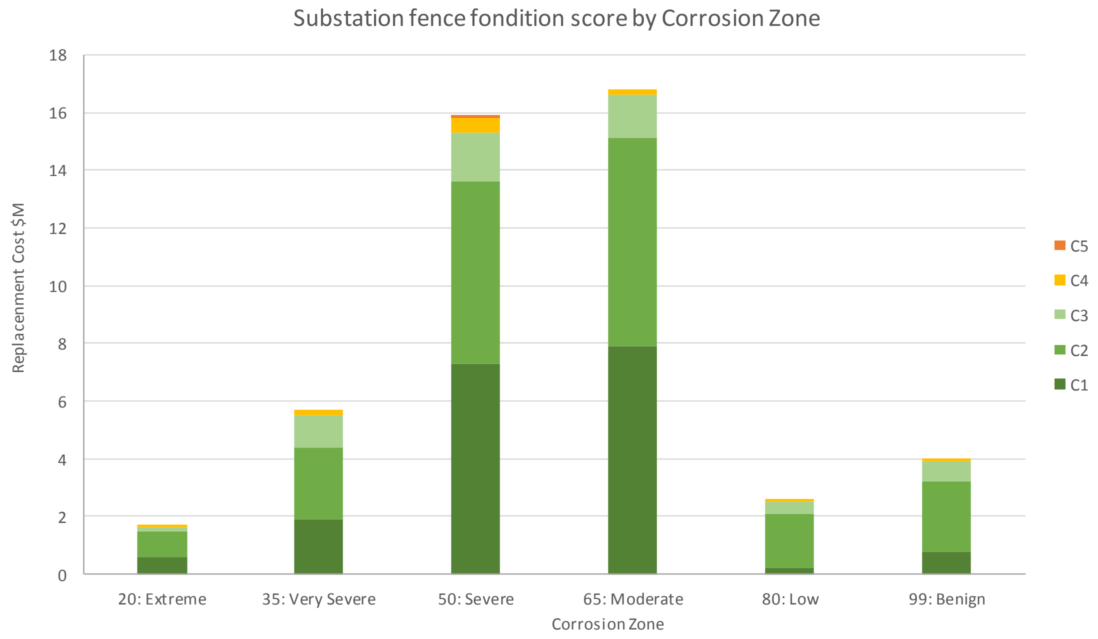
Table 27 Substation fencing standard asset lives

Fence type	Standard asset life (years)
ODS fences & components	50
Power fences & components	50
Security fences & components	50
Perimeter/stock fences & components	25

Figure 32 shows an overview of the condition of substation fencing by corrosion zone. It shows that the majority of fences are in moderate to very good condition, reflecting the historic spend in RCP1 and RCP2 in addressing fencing assets in poor condition.

Transpower has nominated the minimum performance standard for fences as condition score C4 (Poor). In Replacement Cost terms, fencing that does not satisfy the minimum condition represents approximately 3% of the total value of fencing, with the majority of this being in the Very Severe and Severe corrosion zones.

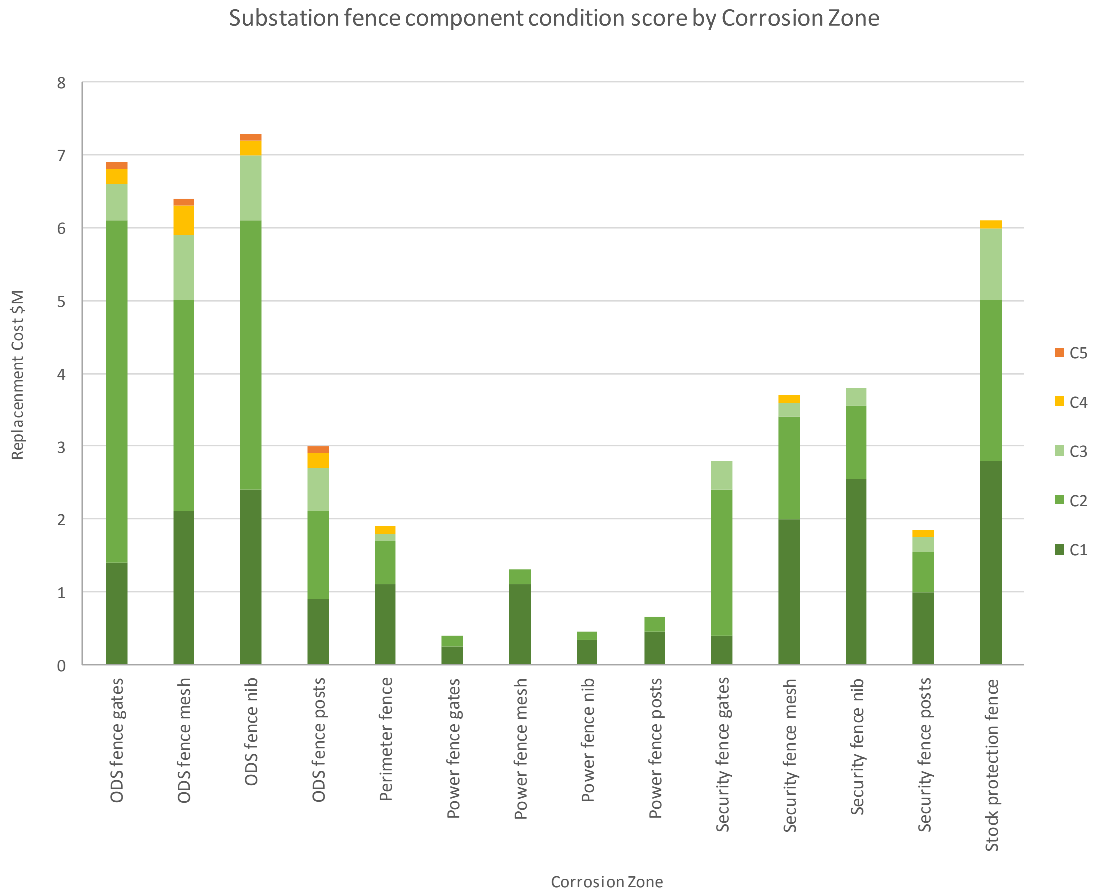
Figure 32 Substation fence condition assessment by corrosion zone



ODS fencing constitutes approximately 50% of the total substation fencing value, and the assets in Poor or Very Poor condition are mainly ODS mesh, nib, structure posts and gates. The RCP3 programme proposed by Transpower focuses on the replacement of these components, together with any concrete fence posts assessed as inadequate to provide site security. Other than ODS fencing, asset criticality is not considered, and prioritisation is done using the priority matrix within SPM Assets that ranks substation sites and identified building importance. Expenditure for ODS fencing is ranked using the standard Transpower risk matrix based on the security of the ODS and site exposure.

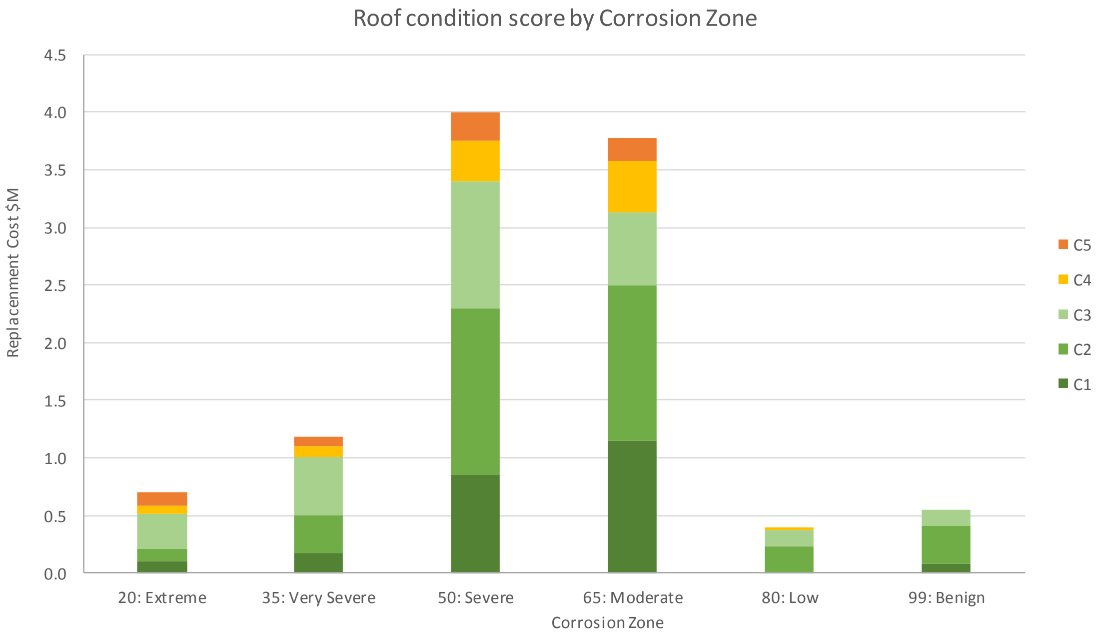
The condition score for fence components is shown in Figure 33. The assets in poor condition (C4 and C5) are predominately ODS fence components.

Figure 33 Substation fence component condition scores



For the second key capex forecast driver, Figure 34 shows the assessed condition for all building roofs by corrosion zone.

Figure 34 Roof condition assessment by corrosion zone



The majority of roof types are colour steel and metal roofing, with 89% of colour steel roofing are in acceptable condition (C3 or better), and 77% of metal roofing in good condition. Most of the relatively low percentage of roofing (in replacement cost terms) in poor condition are currently located in severe corrosion zones, and this is a key consideration in prioritising replacements.

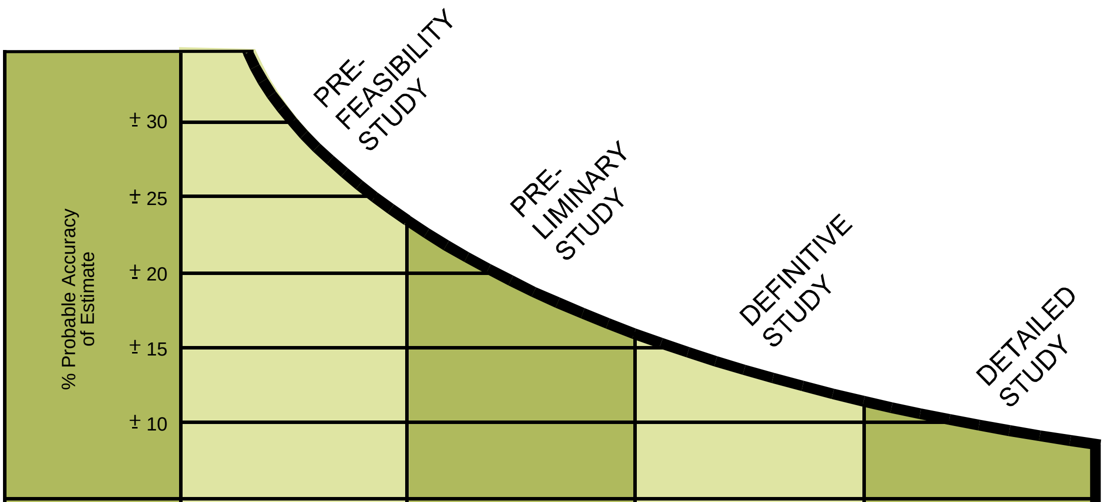
The other key problem for improving performance in weather tightness for substation buildings is that historically control building design included flat or low-pitched roofs with butyl rubber membranes and internal gutters that posed risk to water ingress due to slow draining of rain. In time, these membranes have been found to deteriorate and constant maintenance is required. As buildings of this construction reach the end of their operational life, the roof is replaced with a pitched roof.

D Transpower's cost estimation practices

D.1 Accuracy of estimates

The graph shown in Figure 35 indicates the levels of accuracy that can be expected for estimates prepared for capital works at various stages of a project development. Due to the different levels of engineering input, and completeness in the design, there are various levels of accuracy that can be reasonably expected in forecasts.

Figure 35 Standard estimate accuracy levels



Type of Estimate	Order of Magnitude	Preliminary	Definitive	Detailed
Provided Documentation	• Product capacity and Location • Cost Data on Similar Projects • Major Equipment List	• Preliminary Equipment List • Engineering Line Diagram • Plant Outline General Arrangement • Maps and Surveys • Bench Test Results • Nature of Facilities	• Equipment Specifications and Vendor Quotations • Construction Schedule • Electrical One Lines • Piping and Instrumentation Flow Diagrams • Soil Data and Architect Features • Site Survey and Labour Complete	• Bulk Material Specifications and Vendor Quotes • Construction Specification and Sub Contractor Quotations • Engineering Advanced Approximately 10%
Definition of Scope of Work	Conceptual	Approximate	Clearly Described Essentially Complete	Complete. Well Detailed
Estimating Procedure	Factoring	Combination of Factoring and Quantity Take-Off	Most Quantity Take-Off. Very little Factoring	Complete Quantity Take-Off
Use of Study	Comparison/ Rejection	Final Feasibility	Budget	Funding

We are of the opinion that consideration must be given to the level of accuracy that can be achieved in generating indicative cost estimates for capex and opex expenditure forecasts for the different categories.

Table 28 shows the classification of estimates as defined in the AACE International *Recommended Practice No. 17R-97 Cost Estimating Classification System*.

Table 28 AACE IRP No. 17R-97 generic cost estimate classification matrix[7]

Estimate Class	*Primary Characteristic*	*Secondary Characteristic*			
	Level of Project Definition Expressed as % of complete definition	**End Usage** Typical purpose of estimate	**Methodology** Typical estimating method	**Expected Accuracy Range** Typical +/- range relative to best index of 1 (a)	**Preparation Effort** Typical degree of effort relative to least cost index of 1 (b)
Class 5	0% to 2%	Screening or Feasibility	Stochastic or judgement	4 to 20	1
Class 4	1% to 15%	Concept Study or Feasibility	Primarily stochastic	3 to 12	2 to 4
Class 3	10% to 40%	Budget, Authorisation or Control	Mixed, but primarily stochastic	2 to 6	3 to 10
Class 2	30% to 70%	Control or Bid/Tender	Primarily deterministic	1 to 3	5 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Deterministic	1	10 to 100

(a) If the range index value of 1 represents +10/-5%, then an index value of 10 represents +100/-50%

(b) If the cost index of 1 represents 0.005% of project costs, then an index value of 100 represents 0.5%

For any comparison with Transpower estimates for similar projects, based on these estimate classifications we would adopt a nominal criterion of ±20% as the first pass for comparing the Transpower estimates with our reference comparative estimates as a test for reasonableness. Where there was variance between the Transpower allowance for a network programme or standard maintenance job and our comparative estimate of less than ±20%, we would consider the Transpower estimate to be reasonable and no further detailed assessment would be undertaken.

For those Transpower estimates where the variation is outside our nominal ±20% range, we would review any known project specific issues to identify the potential reasons.

[7] *AACE International Recommended Practice No. 17R-97 Cost Estimating Classification System*, p. 2

D.2 Contingencies

The Commerce Commission in their recently published Opex Input Methodology statement includes the following provision:

> *10.6 a description and quantification of any contingency amounts that are included in the RCP3 opex proposal, the methodology for calculating those contingency amounts, and how the contingency amounts apply to specific identified programmes, where relevant*

Similarly, the Capex Input Methodology of 2012 includes the following information requirement:

> *F5 Cost and efficiency …*
>
> *(3) description of-*
>
> *(a) any contingency included in proposed costs; and*
>
> *(b) the methodology for calculating such contingencies;*

We noted that Transpower were explicit in saying that there were no contingency sums included in their capex and opex estimates.

The AER has previously published expenditure assessment guidelines for capital and operational expenditure, but these are silent on the question of contingency sums.

For a review GHDA has previously done for an Australian utility, there was no mention of contingencies in the capex forecasts. In their case, the estimates for capex was typically class 4 or class 5, which already have ranges of accuracy of ±30% to ±40% and so the inclusion of contingency sums for so-called uncertainties would actually be double-dipping on any uncertainty risk associated with the forecast. That is, given that estimates of that nature are based on limited scopes, the relatively high accuracy range would already be considering uncertainty.

In their analysis on behalf of the AER, EMCa was critical of TransGrid for including contingency allowances in their 2018-23 capex forecasts, particularly on projects that had been on the books for some time and had gone through a number of phases which had clarified project scope. An extract from their report *Review of aspects of TransGrid's revised forecast capital expenditure* for period 2018-23 reads:

> 312. *TransGrid state that the cost estimate accuracy is ±25%.[156] TransGrid also incorporates a contingency allowance in its estimate which is its estimate of the amount needed to render the overall estimate at a P50 level of accuracy. This is a lower level of estimate accuracy than we would have expected for a project of this size at its current state of development, particularly given the proposed commissioning date (prior to summer 2022/23).*

313. *The information we have reviewed leads us to conclude that the accuracy of the cost estimate should have been improved. For example,*

- *TransGrid engaged AECOM to carry out a route selection project in 2014, which (using the AECOM terminology/definitions) was defined as a Pre- Feasibility study with estimates classified as being "Order of Magnitude" at ±25% accuracy. Since 2014, substantial further work has taken place including detailed studies of access issues and options at each of the termination substations as well as significantly upgrading the level of detail on the main 330 kV cable route, which was reported in mid-2017.159 In addition, detailed searches have been undertaken on the services along the chosen route to help identify specific excavation issues; and*

- *TransGrid has identified a prospective cable supplier and we would expect that up-to-date material costs should be available (to compare with assumptions based on previous 330 kV cable projects). Whilst TransGrid has identified some issues with the regulatory body for roads (Roads & Maritime Services, RMS) over the depth of laying the circuits, there should be good excavation and reinstatement cost data available on the roadworks aspects of the project.*

314. *Based on the available information, we consider that the most components of the cost estimate should be approaching an accuracy of ±15% or better, with the few specific cost components that are not well defined, based on P50 estimates from the best available data.*

315. *We have assessed the reasonableness of TransGrid's cost estimates for the major cost components of the scope, including TransGrid's adjustment factors (i.e. DCF, NCF and AWF), property, and contingency. We have also sought to identify any aspects of scope that we consider should not be included, or are missing, or are over- or under-stated.*

EMCa concluded …

328 TransGrid has allowed a risk-based contingency amount of $7.8 million (3%) referred to as a 'scope allowance' for the 330 kV cable and GIS components. This is dominated by an allowance for route length uncertainty, with smaller amounts for GIS switchgear interface issues, property purchase cost variance, weather impacts, and design delays. TransGrid has not included any provision for financing costs in its scope allowance.

329 We have considered whether it is reasonable for TransGrid to add a contingency amount to the whole project to achieve a P50 level of accuracy. Given the other adjustment factors and the stated level of accuracy, we consider that sufficient allowance for unbiased contingency is already included and that it is not reasonable to include this additional risk-based contingency amount.

The AER agreed with EMCa, and ruled:

In response to EMCa's findings, TransGrid submitted that:

313. *The scope allowance is necessary to provide a P50 estimate. TransGrid referenced a consultant's report that indicated it did not include sufficient allowance for unbiased contingency. TransGrid also cited a change in scope and change in other costs that had already increased the cost of these items.*

314. *The estimated cost to meet RMS requirements is based on the best currently available information. EMCa's recommended reduction appears without basis and arbitrary.*

315. *Night works are not covered by the AWF, and the allowance for night works should not be removed. TransGrid submitted that the AWF is a provision for base scope items that are not covered within the base rates of work. The past projects used to estimate current rates did not include night works. Consequently, the AWF does not include night works.*

We are not satisfied TransGrid requires a general scope provision to achieve a P50 estimate of cost. In particular, TransGrid did not address EMCa's concern that a general scope contingency should not be required at this stage of the planning process. We also note that TransGrid has pointed to areas where the costs may potentially increase in support of a general provision, but has omitted any potential savings. We are satisfied with EMCa's advice that specific provisions are included to achieve a P50 estimate, and a general provision is not appropriate.

In the TransGrid case, we are of the opinion TransGrid effectively argued against their own preferred position by claiming a certain level of accuracy on their estimating system but then stating "but it doesn't allow for this or that so we need to add in a nominal contingency." By having a project that has clearly become well defined, TransGrid has implied that the project costs should be more knowable. We are not surprised the AER disallowed a contingency sum in this instance.

In a 2015 decision for a water utility Queensland Urban Utilities (QUU), the Queensland Competition Authority (QCA) required a standardised approach to the treatment of contingency allowances. In doing so, there are examples in the QCA decision where the level of contingency proposed by QUU was questioned and subsequently adjusted.

We believe any inclusion of a contingency sum would have to be fully justified, including why it has been included (i.e. what is it related to) and why it is the value that it is. It will be related to the accuracy of the original estimate, and will need to be explicitly required to mitigate against an identified risk. The important aspect would be the separate consideration of an individual project *estimate* which for the purposes of gaining approval through gates in a governance system may include a contingency sum because of limited project scope and incomplete investigations to understand all of the factors affecting the project, and a *capex forecast* which is likely to include both well-defined and speculative projects.