SA Power Networks

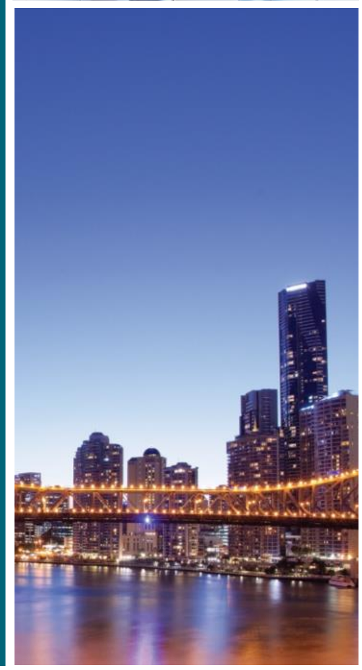
Supporting document 4.2

GHD Regulatory Depreciation Approach

2020-2025 Regulatory Proposal

January 2019

GHD Advisory



Regulatory depreciation approach for electricity distribution assets

SA Power Networks

29 January 2019

GHD

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1. Executive summary

1.1 Review of Asset Depreciation Lives

SA Power Networks is the sole electricity distributor in South Australia. It delivers electricity through distribution networks throughout most of the state. The network is made up of poles, conductors and substations to distribute electricity. SA Power Networks is subject to economic regulation via the Australian Energy Regulator (AER) and the Essential Services Commission of South Australia (ESCOSA).

SA Power Networks has engaged GHD Advisory to assist in assessing the economic life (for regulatory depreciation purposes) of certain assets primarily associated with its replacement and refurbishment programs. Under clause 6.5.5(b) of the National Electricity Rules, SA Power Networks' depreciation schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of asset.

In this report we have considered the economic life of the following classes of assets:

- Stobie poles
- Pole top structures
- Switching cubicles (load break switches, ground level)
- Reclosers and sectionalisers
- Non-category other sub-transmission system and distribution network assets
- Substation power transformers
- Substation circuit breakers and switchgear
- Non-category substation assets
- Distribution pole transformers and ground outdoor substation assets.

In undertaking this assessment, we have considered depreciation lives of the assets within the replacement and refurbishment programs by:

- Assessing expenditure related to refurbishment and replacement of assets
- Considering how expenditure is used to extend the operating life of particular assets, having regard to the asset strategies and risk assessments undertaken by SA Power Networks for each particular class of assets
- Considering the impact of replacement and refurbishment expenditure with regard to the expenditure applied to perpetual life assets
- Conducting an independent engineering assessment to evaluate the remaining useful operating life of assets for refurbishment expenditure

We understand that this report will be provided to the AER by SA Power Networks in support of its' regulatory proposal and as part of a wider submission to the AER. Although some of the arguments advanced in this report may be relevant to the asset lives at other electricity distribution businesses, our conclusions are based on information that is specific to SA Power Networks and the environment within which it operates. This report should not be used to draw conclusions on the appropriateness of asset lives at other infrastructure facilities.

1.2 Key findings

Key finding 1: The current AER-approved lives (Standard AER lives)[1] should generally apply to replacement assets[2] as electricity assets are intended to have a perpetual life

Assets that are replaced on the network (such as lines, substations and communications) are typically installed with the intent to maintain the life of a distribution line or substation in perpetuity. Under this scenario, it is appropriate that the Standard AER lives apply to these new assets.

Key finding 2: Refurbished Assets[2] - the economic life for depreciation for refurbishing asset components is shorter than that of a new parent asset, and is typically around half of the economic life of a new asset.

The decision to refurbish an asset rather than replace it is based on whether the costs will be minimised over the remaining operating life of the asset, having regard to any increased risk of failure of a refurbished asset when compared to a new asset. Examples of this include the plating of stobie poles and the refurbishment of bushings, windings and tapchargers on power transformers.

Refurbishment expenditure on an asset component is aimed at maintaining or extending the life of the parent asset. These interventions typically occur between mid and near end-of-life of the parent asset. Hence, we find that the appropriate period for depreciating refurbishment expenditure on an asset component is shorter than that of its parent asset.

Key finding 3: Electronic Network Assets – Electronic type assets installed on distribution lines and in substations have a much lower economic life than the standard AER lives.

Our findings show that Electronic Network Assets which includes electronic devices installed in substations such as SCADA devices and protection relays, and electronic devices installed on HV and LV feeders, have operating lives often determined by the inability to support ongoing maintenance as well increasing failure rates requiring replacement programs around 15 years of age. This is distinctly different than the standard AER life for distribution lines and substations and therefore we recommend a separate asset live for depreciation treatment.

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[1] Standard lives are set out in the AER's "Final Decision SA Power Networks determination 2015-16 to 2019-20 Attachment 5 – Regulatory depreciation", October 2015

[2] AER, DRAFT Industry practice application note – Asset replacement planning, 2018

Summary of key findings by asset category

We initially analysed replacement or refurbishment expenditure on an asset by asset basis to first determine an appropriate economic life aligned to the remaining operating value of each asset type.

This analysis led to the conclusion that generally depreciation on expenditure for asset replacements can be treated the same as new assets and that depreciation on expenditure for refurbished assets is shorter than that of a new parent asset, and is typically around half of the economic life of a new asset. While some assets indicated an assessed economic life some higher and some lower, it is recommended to group refurbishment expenditure on assets belonging to sub-transmission and distribution lines to one new shorter life classification, and similarly refurbishment expenditure on assets belonging to substations to a second new shorter life classification (on a weighted average type approach similar to new assets).

During the review of replacement and refurbishment expenditure, it was also found that new electro-mechanical type assets installed on lines (eg. reclosers, sectionalisers and voltage regulators) had a shorter economic life than the Standard AER life of 55 years. The expenditure for both new and replacement equipment of this type can be grouped into the new 25 year short-life asset class. Refurbishment expenditure, which is only relevant for reclosers, could either have a separate 10 year asset class or could also be grouped into the 25 year short-life asset class.

A third and separate category is recommended for electronic network assets installed within substations and on HV and LV feeders with a life of 15 years, and for both new and replacement devices.

The table below details the summary of key findings by asset category. We are instructed that SA Power Networks applies straight line depreciation to the below asset groups. We consider that approach appropriate and consistent with Rule 6.5.5(b).

Table 1: Summary of findings by asset category

Expenditure category	Current asset depreciation class	Current AER-approved Standard Life	GHD recommended depreciation life	
		Replacements/ Refurbishments	Replacements	Refurbishments
Stobie poles	Sub-transmission lines Distribution lines	55 years	55 years	25 years
Pole top structures	Sub-transmission lines Distribution lines	55 years	55 years	n/a
Switching cubicles	Sub-transmission lines Distribution lines	55 years	55 years	25 years
Reclosers and sectionalisers	Sub-transmission lines Distribution lines	55 years	25 years	10 years[3]
Non Category – Line Assets[4]	Sub-transmission lines Distribution lines	55 years	25 years	n/a
Distribution transformers	Distribution transformers	45 years	45 years	20 years

[3] Create a separate 10 year asset class for recloser refurbishment or group into the one common 25 year short-life asset class

[4] Other sub-transmission system and distribution network assets (pole top voltage regulators and pole top capacitors)

Expenditure category	Current asset depreciation class	Current AER-approved Standard Life	GHD recommended depreciation life	
		Replacements/ Refurbishments	Replacements	Refurbishments
Substation power transformers	Substations	45 years	45 years	20 years
Substation circuit breakers and switchgear	Substations	45 years	45 years	20 years
Non Category Substation asset	Substations	45 years	45 years	20 years
Electronic Network Assets	Sub-transmission lines Distribution lines Substations	55/45 years	15 years	n/a

Source: GHD Advisory

2. Background

SA Power Networks is the sole electricity distributor in South Australia. It delivers electricity through distribution networks throughout most of the state. The network is made up of poles, conductors and substations to distribute electricity. SA Power Networks is subject to economic regulation via the Australian Energy Regulator (AER) and the Essential Services Commission of South Australia (ESCOSA).

SA Power Networks has engaged GHD to assist in assessing the economic life (for depreciation purposes) of certain assets associated with its replacement and refurbishment programs. Under clause 6.5.5(b) of the National Electricity Rules, SA Power Networks' depreciation schedules must depreciate using a profile that reflects the nature of the assets or category of assets over the economic life of that asset or category of asset.

The standard lives for new assets approved by the AER are shown in Table *2* below. These classes of assets form the scope of our review in respect of refurbishment and replacement expenditure.

Table 2: AER Approved standard asset lives

Asset classification	Standard life
Sub-transmission lines	55 years
Distribution lines	55 years
Substations	45 years
Distribution transformers	45 years
Low Voltage Supply	55 years
Communications	15 years

Source: Data provided by SA Power Networks

2.1 This report

We have considered the depreciation lives of the assets that fall within the replacement and refurbishment categories. This report is intended to be provided as part of a wider submission to the AER by SA Power Networks.

This report is structured as follows:

- Section 3 provides an overview of regulatory depreciation in the electricity sector
- Section 4 describes our approach in undertaking this assessment
- Section 5 provides a summary of SA Power Network's assets and recommendations of applicable regulatory depreciation treatment and economic life for each asset class
- Section 6 describes our key findings.

2.2 Disclaimer

This report has been prepared by GHD for SA Power Networks and may only be used and relied on by SA Power Networks for the purpose agreed between GHD and the SA Power Networks as set out in section 1 of this report.

GHD otherwise disclaims responsibility to any person other than SA Power Networks arising in connection with this report. GHD also excludes implied warranties and conditions, to the extent legally permissible.

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The opinions, conclusions and any recommendations in this report are based on conditions encountered and information reviewed at the date of preparation of the report. GHD has no responsibility or obligation to update this report to account for events or changes occurring subsequent to the date that the report was prepared.

The opinions, conclusions and any recommendations in this report are based on assumptions made by GHD described in this report (refer sections 3-5 of this report). GHD disclaims liability arising from any of the assumptions being incorrect.

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3. Depreciation of Electricity Assets

3.1 Regulatory depreciation in the electricity sector

‘Building block’ models are used in Australia to calculate the appropriate annual revenue requirement (ARR) of a regulated firm. The ‘building block’ approach is equal to the sum of the underlying cost components faced by a regulated business and reflect an allowance for the return on capital, the return of capital (depreciation), operating expenditure and other items such as taxation allowances.

Australian electricity distribution businesses recover the upfront investment in network infrastructure over the economic life of network assets through the regulatory depreciation allowance. The regulatory depreciation allowance is typically calculated with reference to the value of assets that comprise the regulated asset base (RAB), the assumed capital recovery profile (e.g. straight line depreciation, weighted average life depreciation or diminishing value depreciation) and the economic lives of the assets used to provide the services (that is, the standard economic life for new assets and the remaining economic life for existing assets).

The calculation methodology of the regulatory depreciation allowance is important to ensure the regulatory regime promotes efficiency in pricing (to benefit consumers) and investment (to promote the necessary investments to ensure long run service delivery at a given service standard). There are a number of methods for calculating depreciation. We are instructed that SA Power Networks (and the AER) currently applies straight line depreciation.

Straight line (SL) depreciation is calculated with reference to the acquisition and salvage value of the asset, and the total productive years for which the asset can be expected to be used productively. The salvage value of the asset, in theory, reflects the price the regulated business can reasonably sell the asset once it is no longer needed by the business. The acquisition value reflects the purchase price of the asset. SL depreciation simply subtracts the salvage value from the total acquisition value of the asset and divides this amount through by the useful life. This produces a constant annual depreciation allowance. At the end of the useful life, the asset value is either zero (reflecting a salvage value of zero), or it is reflected on the regulated business’ balance sheet.

Weighted average life depreciation is a form of SL depreciation where asset classes with different economic lives are weighted by relative expenditure to derive the weighted average. For example, this is applied to all assets belonging to distribution lines. Weighted average life depreciation is the form of depreciation often used in the regulated Australian electricity sector in setting standard depreciation rates for assets.

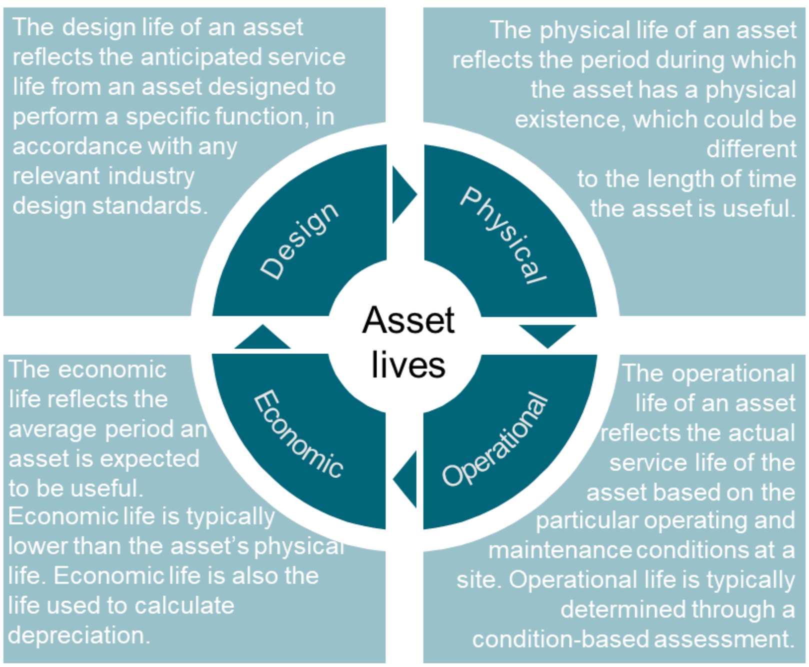
SL depreciation is typically more applicable than Diminished Value (DV) depreciation for electricity network assets as the assets are mature and demonstrate low early life failure rates compared with other industry assets that could have business, market or technology related risks that could impact the value of assets in early life. The SL depreciation methodology aligns well with the remaining operating value of electricity network assets during their asset lives.

3.2 Asset lives, deterioration and failure rates

3.2.1 Asset lives

The assumed capital recovery program and the asset lives of the assets that comprise the RAB are an important feature of the regulatory depreciation allowance. The capital recovery program reflects the asset life of assets, that is, it reflects the length of time that an asset is expected to efficiently and reliably provide the service for which it was designed. Asset lives also assist in determining suitable asset maintenance and replacement regimes, which impacts operating and capital expenditure forecasts over a regulatory period. Asset lives can be determined by technical, economic, and/or strategic methods. An overview of some of the different types of asset lives are depicted in Figure *1*.

Figure 1: Asset lives



Source: GHD Advisory

Under the National Electricity Rules, asset depreciation schedules must "depreciate using a profile that reflects the nature of the assets, or category of assets, over the economic life of that asset, or category of assets".[5] This means that SA Power Networks depreciation schedules must depreciate an asset over the economic life of that asset. The economic life of an asset reflects the period for which an asset is useful to the owner, and in some businesses it can be different to the actual physical or operating life of that asset. In the electricity industry operating life can be used to determine the economic life that is appropriate for depreciation purposes.

In the Australian electricity sector, it is also common for regulators and electricity networks to agree on a weighted average life for asset classes with varying economic lives. That is, there are assets with shorter and

[5] Clause 6.5.5(b)(1) of the National Electricity Rules, available at: https://www.aemc.gov.au/regulation/energy-rules/national-electricity-rules/current

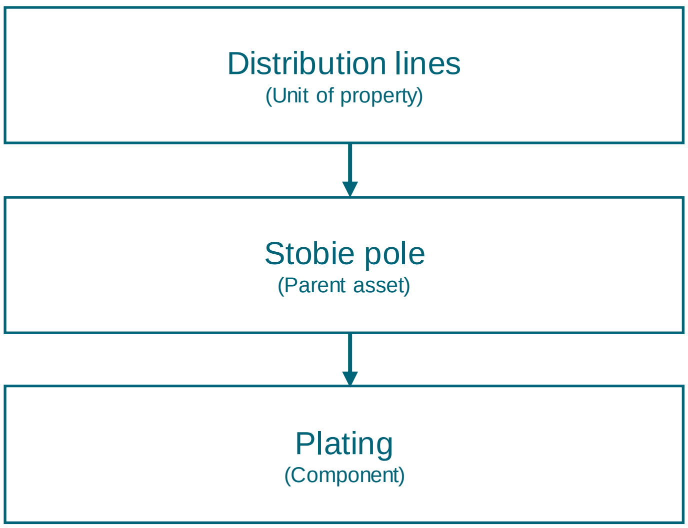
longer operating lives around a mid-point for each asset class which is determined by a weighted average approach based on relative expenditure.

Where our report refers to asset lives for new assets, we are referring to the standard lives as approved by the AER and shown in Table *2*. This asset life is referred to as the Standard AER life in this report.

3.2.2 Distribution network assets

Distribution network assets primarily consist of sub-transmission lines, distribution lines, substations and communication systems. These primary assets align with a "unit of property" as defined in section 82AT of the *Income Tax Assessment Act 1936 (Cth)*.[6] For the purposes of this report, we consider a unit of property as an asset with a hierarchy of parent assets underneath, which in turn has components which can be refurbished. For example, a distribution line is the unit of property that contains a stobie pole as the parent asset and plating is a component used to refurbish the parent asset. This hierarchy is illustrated in Figure *2* below.

Figure 2: Illustration of asset hierarchy



Source: GHD Advisory

3.2.3 Asset refurbishment and replacement programs

Asset refurbishment typically involves replacing components of parent assets or adding components to the asset to reduce potential failure modes. For example, stobie poles can be plated to extend the life of the poles when corrosion has weakened the strength of the pole below ground level. The duration that the refurbishment expenditure will provide value will depend on the asset as a whole and its remaining operating life. Since most refurbishment expenditure occurs between mid-life and the end-of-life of the asset, the depreciable life for refurbished expenditure should be less than the parent asset's original expected operating life.

When an asset is completely replaced the life of the asset is defined by the expected life of the "unit of property". Distribution lines or substations in an electricity network are continually kept to a minimum condition to meet service and performance objectives, and are known as perpetual assets. For assets replaced on a perpetual

[6] Income Tax Assessment Act 1936 (Cth), available at: http://classic.austlii.edu.au/au/legis/cth/consol_act/itaa1936240/

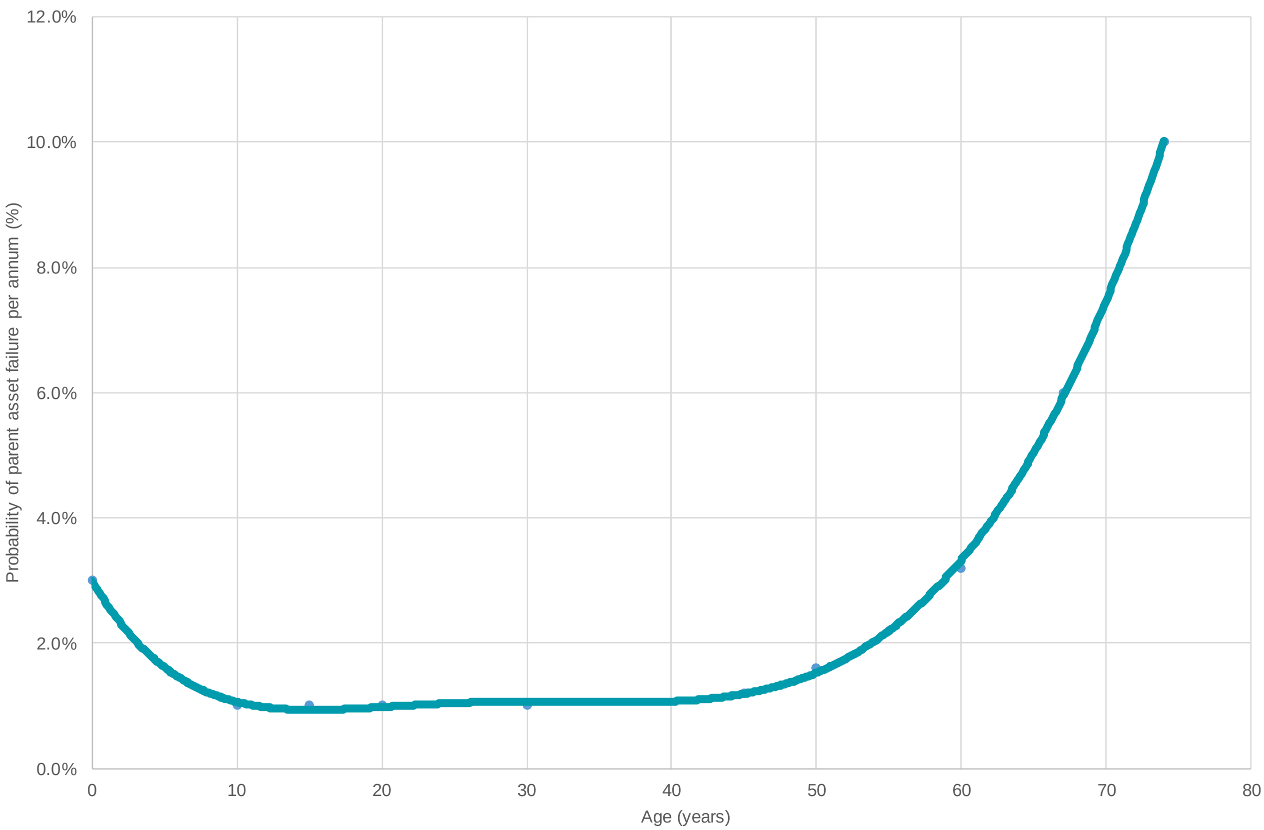
“unit of property” asset, the Standard AER life should apply to the replaced asset, since the majority of assets installed on a perpetual unit of property are expected to reach their standard life.

3.2.4 Failure rates

Asset plans define the population, age and ongoing risk of operating assets with and without intervention. An understanding of the failure modes and expected failure rates as an asset ages, or is utilised in the environment it operates within, can define the economic life of the asset. This in turn assists in determining the appropriate depreciation methodology to apply to that asset.

The reliability function[7] refers to the rate of failure of an asset at a given age (risk of failing to provide value). An example of a reliability function is the ‘bathtub curve’, which has a higher rate during early life, then decreasing to some minimum and random failure rate, before increasing again as the asset wears out at the end of its life due to inherent asset failure modes or due to increased vulnerability to faults or extreme weather events. This is depicted in Figure *3*.

Figure 3: Illustrative example of the ‘bathtub curve’ reliability function



Source: GHD Advisory

[7] Also referred to as a hazard function

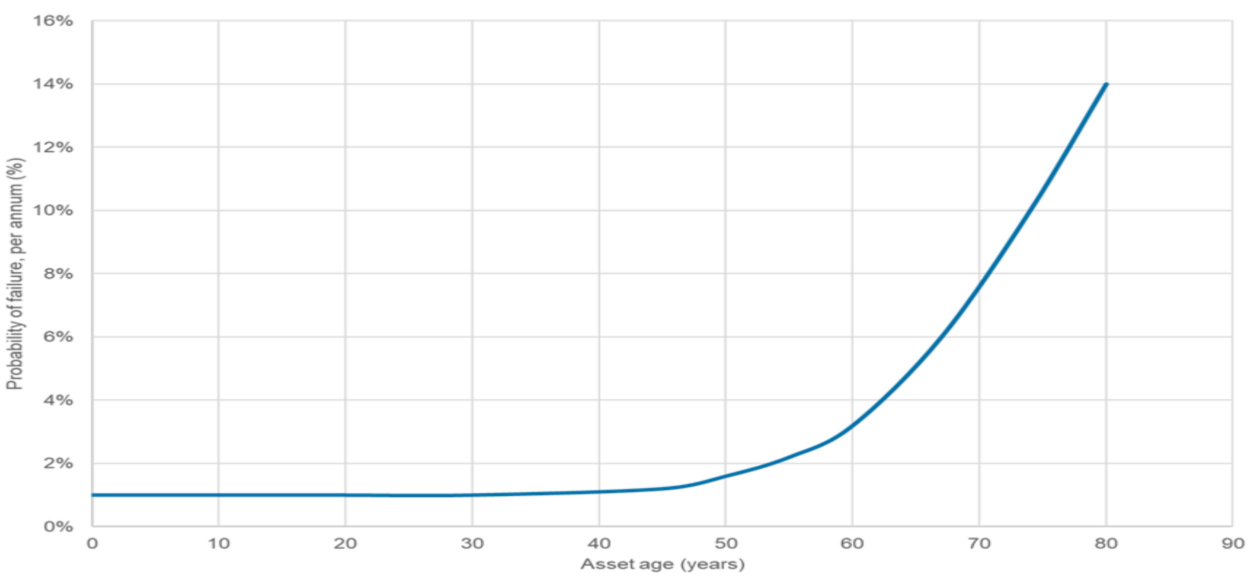
Importantly, age is not the sole underlying factor that drives increased failure of an asset. Factors such as environmental conditions (such as corrosion zones), operating temperature, moisture ingress and utilisation can significantly affect asset condition and bring forward the age in which failure rates increase.

The reliability function considers failures over time of new assets and failures due to inherent or system related failures. The reliability function can also be used to determine the economic asset life for a fleet of assets and for determining the appropriate depreciation methodology to apply to those assets. *Figure 4* depicts an indicative power transformer reliability function for a fleet of transformers used in electricity networks. The actual age in which an individual transformer may enter end of life depends on operating life conditions, particularly thermal loading. For power transformers, the failure rate remains at approximately 1 per cent during early and mid-life of the asset, with the probability of failure then increasing sharply towards the end of life with the last transformer remaining in service at around 80 years. Risk assessments use these functions, along with criticality, to determine optimum timing for replacement intervention.

Note that the reliability function typically does not consider failures due to third party damage or from extreme weather events. Notwithstanding this, these factors should be included to assess the economic life for depreciation purposes.

The failure rate of assets during early and mid-life periods and end-of-life replacement strategies provide input to a model which is used to determine remaining operating life and the economic life for each asset category.

Figure 4: Power transformer reliability function (representing a fleet of transformers)



Source: GHD Advisory

4. Assessment framework and methodology

This section details the assessment framework and the methodology applied to assess the economic life of certain assets associated with SA Power Network's asset replacement and refurbishment programs.

The analysis considers how expenditure is used to extend the life of a particular asset, having regard to the asset strategies and risk assessments undertaken by SA Power Networks for particular assets. Our review has been limited to the following asset categories:

- Stobie poles
- Pole top structures
- Switching cubicles (load break switches, ground level)
- Reclosers and sectionalisers
- Non-category other sub-transmission system and distribution network assets (voltage regulators and pole mounted capacitors)
- Substation power transformers
- Substation circuit breakers and switchgear
- Non-category substation assets
- Distribution pole transformers and ground outdoor substation assets
- Electronic network assets

In performing this analysis we have undertaken an independent engineering assessment to evaluate the remaining operating life of the above assets related to refurbishment and replacement expenditure. Operating life for a population of assets will vary from near zero (due to early life failures) to the maximum life (usually due to replacement). We have conducted our own independent survival analysis of assets on an asset-by-asset class basis using data in SA Power Networks Asset Strategy documents and other industry data available to GHD. The analysis calculates the number of units failing each year according to the asset's reliability function plus the number replaced at the end of the asset's useful life and subtracts this number from the total. This is then used to model the remaining value of the assets over time based on the remaining operating life of the assets. We then match a SL depreciation profile over the early and mid-life periods. The intersection with zero remaining value will determine an appropriate economic life for the assets with SL depreciation. Note that some assets in a population will often have an operating life beyond the determined economic life.

We initially conducted this analysis of replacement or refurbishment expenditure on an asset by asset basis to first determine an appropriate economic life aligned to the remaining operating value of each asset category. This assumes a population of the assets is installed in a particular year, and the assets in that population are modelled over the population's life until the last asset has either failed or has been removed from service.

This analysis led to the conclusion that generally depreciation on expenditure for asset replacements can be treated the same as new assets and that depreciation on expenditure for refurbished assets is shorter than that of a new parent asset, and is typically around half of the economic life of a new asset. It was found that an appropriate approach was to group refurbishment expenditure on assets belonging to sub-transmission and distribution lines to one new shorter life classification and similarly refurbishment expenditure on assets belonging to substations to a second new shorter life classification (a weighted average type approach similar to the new asset classes).

We have relied on data and information contained in SA Power Networks' asset management strategies and the Power Asset Management Plan (PAMP), and other information provided by SA Power Networks to make an assessment of the reliability functions in each case along with our experience and GHD available data.

Decision making process for applying different regulatory depreciation treatments

We developed a decision-making process to determine whether different regulatory depreciation treatments were more appropriate to apply when compared with current Standard AER asset lives and SL depreciation.

This process is shown in *Table 3*. It considers a refurbished asset when it is a component of a parent asset and replaced assets as part of "unit of property". The "unit of property" being equivalent to the asset types agreed with the AER for depreciation purposes.

Assets that are replaced on network assets (Lines, Substations and Communications) are typically installed with the intent to maintain the life of the network asset in perpetuity. Under this scenario the Standard AER asset lives for new assets would still apply. There is a possibility, though, that a network asset could be removed or replaced as a whole within the economic life of some of the previously replaced assets.

Following discussions with SA Power Networks, even though using DV depreciation would be an appropriate method to address this risk, it was agreed that these circumstances seldom occur and that any benefit would be outweighed by the added complexity and we understand SA Power Networks will continue to apply the SL approach. We did however leave this scenario within the decision making process for completeness.

In the summary of asset replacement expenditure on an asset-by-asset assessment for depreciation treatment we also recommended that expenditure on new assets be depreciated using the AER standard lives using SL depreciation. For expenditure on refurbished assets, we considered that a weighted average approach with shortened economic lives (at around half the economic life of new assets) be adopted with SL depreciation for refurbished assets.

Table 3: Decision making process - depreciation methodology and economic life

Asset expenditure type	Question 1	Question 2
<u>Replacement Expenditure</u> Replaced asset which is part of a "unit of property". *(e.g. conductor, poles, pole mounted plant and equipment forming part of a distribution feeder)*	Is the replaced asset extending the life of the "unit of property" with the purpose of maintaining a perpetual operating life of the "unit of property"? Yes – use the Standard AER life for new assets and apply SL depreciation No - the "unit of property" asset may have a remaining economic life less than the Standard AER life for new assets – consider Question 2	Does the modelling of the remaining operating value over the life of the assets justify a change to the economic life and to SL depreciation? Yes - consider DV depreciation if survival risk is high in the early years otherwise use SL depreciation with a shorter economic life No – use the Standard AER life for new assets and apply SL depreciation
<u>Refurbishment Expenditure</u> This expenditure on an asset or a component aims to extend the operating life of an asset in current poor condition *(e.g. stobie pole plating)*	Does the modelling of the remaining operating value over the life of the refurbished assets justify a change to the SL depreciation approach? Yes – consider applying DV depreciation over the remaining operating life of the refurbished assets if the survival risk is high in the early years No - apply SL depreciation and consider the remaining operating life to determine an economic life for refurbished assets	Not required

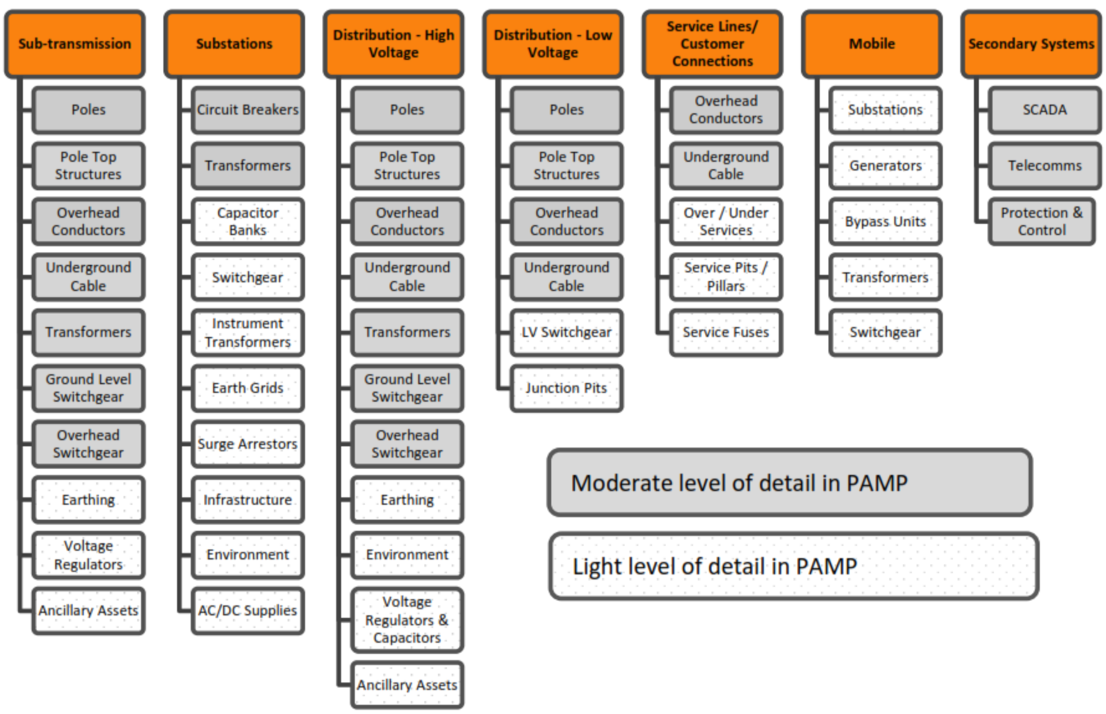
Source: GHD Advisory

5. Analysis of assets and applicable regulatory depreciation treatment

5.1 SA Power Network Asset Strategies

SA Power Networks classifies its assets into asset classes and develops asset management strategies and plans for each asset class as shown in Figure *5*. The asset strategies provide data and information on the asset replacement and refurbishment strategies defining the expenditure needs for the next reset period and beyond. Figure *5* shows the asset hierarchies covering the assets we have reviewed for the purposes of our assessment.

Figure 5: SA Power Networks systems and asset breakdown



Source: SA Power Networks (2018), *Power Asset Management Plan – Manual no. 16,* pg 142

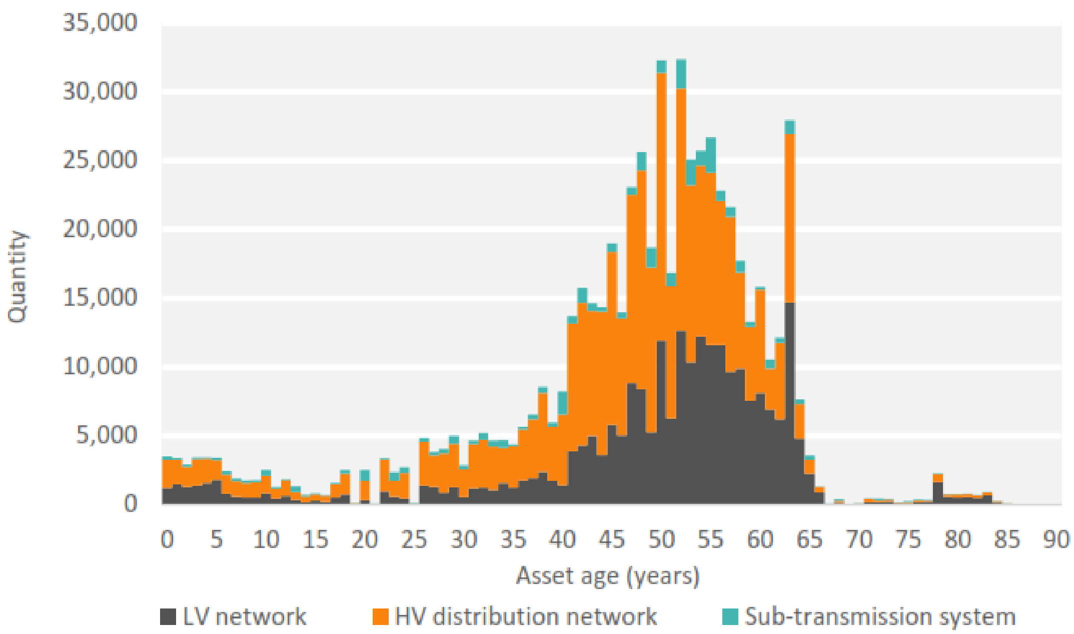
5.2 Expected life of replaced and refurbished assets

5.2.1 Stobie poles

Poles are the support structure for overhead conductors to provide the required clearances from ground level and other objects to achieve safety clearances. The remaining strength of the structure is key to determining the end of life of a pole. Stobie poles are unique in South Australia and have largely remained unchanged since their initial introduction in the 1920s. Stobie poles consist of a concrete core with two outer steel beams connected by bolts to ensure strength. Footings made from reinforced concrete are used to ensure that poles are securely anchored into the ground.

There are approximately 647,492 poles across the network.[8] *Figure 6* shows the age profile of the poles. The age profile of the poles reflect the significant electrification projects commencing from the early 1950s, and a significant proportion (approximately 74 per cent) that are between 40 and 65 years of age. The pole replacement program is reflected in the profile in the past 25 years.

Figure 6: Pole age profile



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 154, unpublished

Current condition data indicates that 90 per cent of poles are currently in good condition, 9 per cent with serious deterioration and 1 per cent having advanced deterioration.[9]

The operating life of new Stobie poles can vary between 20 to 120 years, subject to location in corrosion zones, loading capacity and exposure to extreme weather events.[10] Based on the existing age profile shown in Figure *6*, currently approximately 1 per cent of poles are more than 70 years old. Additionally, the number of poles remaining in service beyond 90 years is minimal.

The most common cause of unassisted pole failures is corrosion combined with large storm/wind events. The end of operating life of a pole is therefore determined by the extent of corrosion, both above ground and at ground level. Particular geographic areas are subject to higher rates of below ground corrosion and this drives much of the variation in the operating life of poles.

[8] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 152, unpublished

[9] Ibid

[10] Ibid

SA Power Networks classifies the network into corrosion zones as shown in Figure *7*. The majority of the distribution network is in the severe (2), very severe (3) and extreme (4) corrosion zones, with a few poles within the benign (1) corrosion zone.

Figure 7: SA Power Networks corrosion zones

Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 26, unpublished

5.2.1.1 Intervention options for stobie poles

Poles with serious defects that have been identified through asset inspections are evaluated for a process called plating. Refurbishment is achieved by inserting steel beams into the ground either side of the pole and welding the steel plates across the corroded section onto sound steel sections of the pole.[11] Refurbishment costs are approximately 15 per cent of the cost of replacing a pole and can extend the operating life of the current pole by 10 to 50 years. Typically, this difference in pole life is also caused by refurbished poles being located in different corrosion zones.

Plating extends the life of the pole below ground level at a significantly lower cost than complete replacement, particularly where there is a suffcient remaining operating life expected for the parent pole. In the lower corrosion zones, the above ground corrosion tends to be lower resulting in a higher proportion of poles being suitable for

[11] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 152, unpublished

refurbishment than replacement. Hence, pole plating is more appropriate in lower corrosion environments and pole replacement is more appropriate in higher corrosion environments.

The replacement and plating volumes that have occurred in 2010 and 2017 are shown in Table *4*. There has been a significant increase in the required interventions over the last seven years.

Table 4: Pole plating and replacement volumes, 2010 and 2017

Intervention	2010 (number, proportion of poles)	2017 (number, proportion of poles)
Plated Poles	333 (0.052%)	1,196 (0.185%)
Replaced Poles	1,566 (0.242%)	5,950 (0.919%)

Source: GHD Advisory analysis based on SA Power Networks (2018) *Poles Asset Plans 3.1.05,* pg 9, unpublished

Currently, approximately 1.1 per cent of total poles have been replaced or plated and the average age of poles is around 45 years. As the average age of poles approaches 70 years in the future, the percentage of poles that have been replaced or plated may increase to approximately 2.5 per cent per annum (approximately 15,000 poles).[12] The failure rate of assets during early and mid-life periods, and end-of-life replacement strategies provide input to determine the remaining operating value of the asset category.

5.2.1.2 Expected economic life of replaced or refurbished stobie poles

The expected economic life of replaced or refurbished stobie poles needs to be determined separately. The parent asset for a replacement pole is the high voltage (HV) feeder (which is also a “unit of property” in the case), while the parent asset for the refurbishment work is the pole.

When considering the expected life of replaced poles, the life should be treated the same as new poles. This is based on the assumption that poles are installed on feeders which will be maintained to a minimum condition into perpetuity. We consider the Standard AER life for distribution lines should also apply to pole replacements, the same as new poles. We therefore consider an economic life of 55 years to be appropriate to apply to pole replacements.

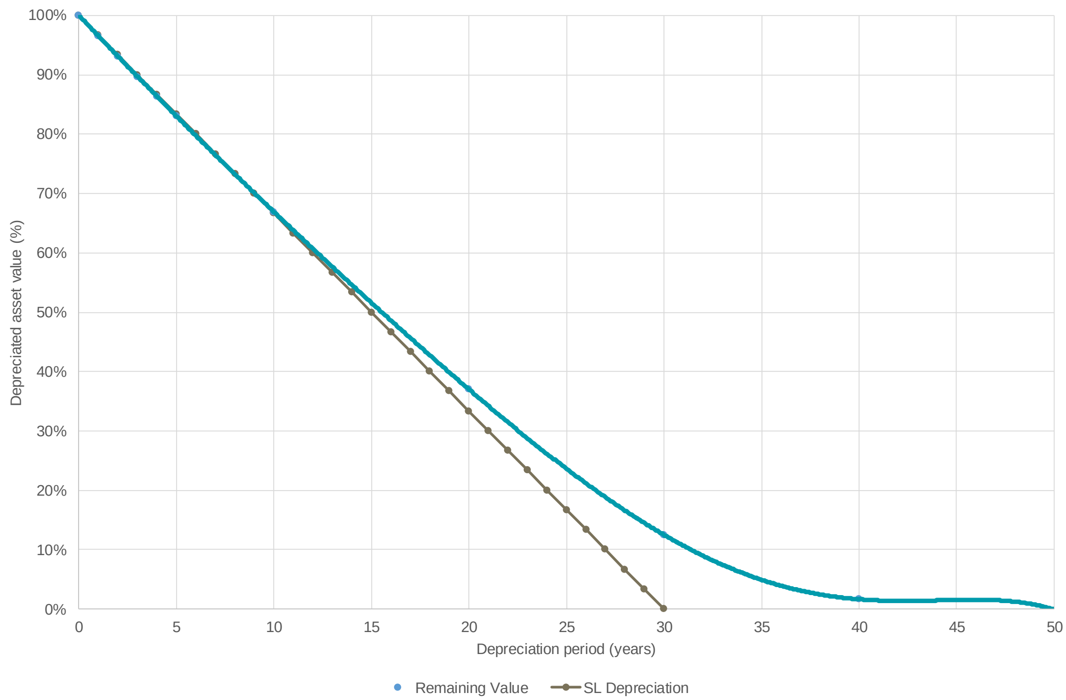
Refurbishment of poles by plating is conducted on poles at some time during mid-life. The extended operating life is expected to achieve between 10 and 50 years, however, this age distribution is likely to be skewed to an average extended life of between 20 and 25 years (typical probability distribution of asset life).

We modelled the risk of parent asset failure by using the remaining operating life of the parent asset and its reliability function. This is presented in Figure *8*.

The reliability function is derived from the current and potential future volumes of pole plating and replacements, along with the projected operating life of a plated pole. Based on the analysis, an economic life of 30 years using the SL depreciation method is shown to be an appropriate life for pole refurbishment expenditure as indicated in Figure *8*. After analysing refurbishment expenditure on a range of assets currently belonging to sub-transmission and distribution lines, it was found appropriate to group expenditure into one new shorter life classification with a depreciation life of 25 years (Short-Life Line Assets).

[12] SA Power Networks (2018) *Poles Asset Plan 3.1.05 published December 2018*

Figure 8: Stobie pole plating – Remaining Operating Value and SL Depreciation



Source: GHD Advisory

5.2.2 Pole top structures

Pole top structures are needed to securely attach overhead conductors to the support structures. These structures include cross arms, insulators, supports for overhead switchgear, joints, connections and other miscellaneous components.

The number of failures of pole top structures has trended upward since 2011.[13] The management of pole top structures is largely based on replacing any that have failed, and identifying defects and prioritising proactive replacements.

While pole top structures may be considered asset replacements, for the purposes of reviewing the expected economic life of the replaced components, the asset class does form components of the parent asset (the pole). Hence, it is subject to the same consideration as refurbished assets.

There are 647,492 poles on the network,[14] implying that there are approximately the same number of pole top structures. SA Power Networks has indicated that pole top structures have an expected operating life of between 40 and 50 years,[15] which is lower than the typical operating life of poles of between 70 and 120 years. Similarly to poles, pole top components are expected to have a lower life in higher corrosion zones and a higher life in low corrosion zones.

[13] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 160, unpublished

[14] SA Power Networks (2018) *Poles Asset Plans 3.1.05,* pg 151

[15] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 160

There is no detailed age profile information available for pole top structures, however, we have assumed that the age of many pole top structures is the same as the age of the parent pole population. We can then assume that most of the pole top structures will be between 40 and 50 years of age and near to end of their life, compared with the typical operating lives of poles which ranges from 70 to 120 years.

The number of failures of pole top structures has trended upward since 2011, up from approximately 0.5 per cent to approximately 0.62 per cent.[16] Proactive replacements are projected to be 1.4 per cent per annum over the next regulatory reset period, hence the total projected replacements is equal to approximately 2.02 per cent per annum. The replacement of pole top structures will likely significantly increase further in subsequent years based on a projected age profile of pole top structures along with an assessed operating life of 40 to 50 years.

5.2.2.1 Refurbishment and replacement strategies for pole top structures

The management of pole top structures is largely based on replacing any that have failed, and identifying defects and prioritising proactive replacements.

Pole top structures are replaced near to the end of their expected life. The replacement strategy is based on managing risk either through identified failures or identification of defects. Where the condition of pole top structures cannot reliably be detected through inspections, and the assets have a high consequence of failure, proactive replacement programs are planned.

5.2.2.2 Expected economic life of replaced or refurbished pole top structures

Replaced or refurbished pole top structures have the same parent asset, being the stobie pole. Because of this, for the purposes of reviewing the expected life of the replaced components, this replacement program should also be subject to the same logic as refurbished assets, and therefore may have a reduced life if the existing pole was to be replaced, compared with pole top structures installed on new poles.

The current age of pole top structures is assumed to be between 40 and 50 years while poles have a typical age of between 70 to 120 years, this means that replaced pole top structure would likely be replaced a second time when the pole is replaced suggesting a life for replaced pole top structures of 30 to 60 years. The life expectancy of pole top structure replacements therefore can still be treated the same as new assets with a Standard AER life of 55 years with SL depreciation.

5.2.3 Switching cubicles (load break switches, ground level)

Switching cubicles are devices mounted on the ground that connect components of the underground cable network. These devices enable the safe connection and disconnection of cables and transformers for operational and maintenance purposes.

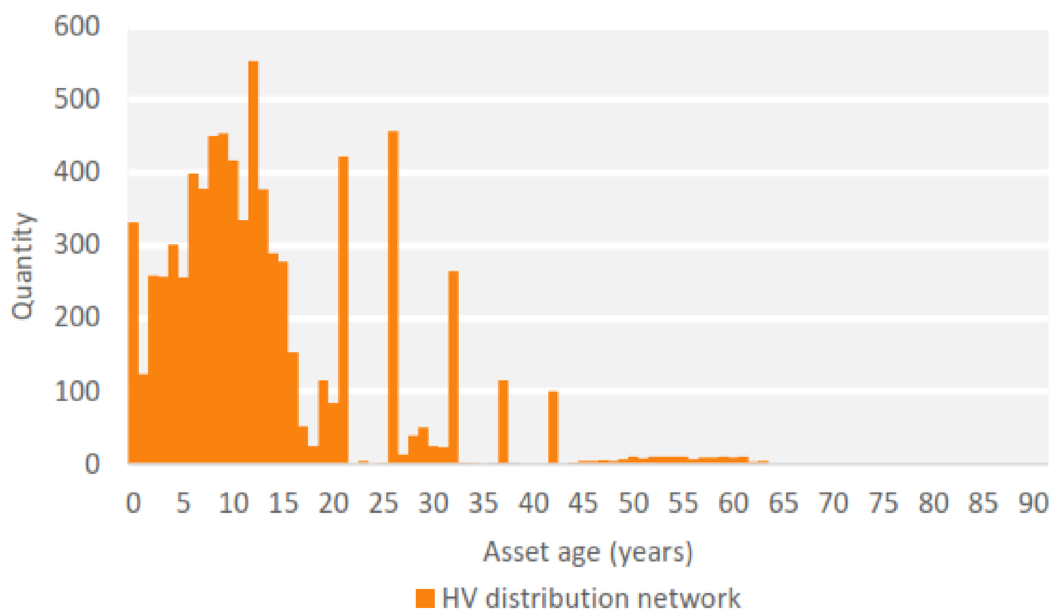
There are 7,551 switching cubicles across the network mainly in the HV distribution network.[17] Figure *9* shows the age profile of switching cubicles. A significant proportion (approximately 78 per cent) are less than 20 years old, reflecting network growth and real estate developments requiring underground cable networks. In addition, many original switching cubicles have been refurbished or replaced.

[16] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 160

[17] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 180

The experience is that the operating life for switching cubicles typically ranges between 15 to 45 years. Specific makes and models of switchgear are known to present safety risks during switching operations, or even when not being operated. Some older switching cubicles are obsolete and no longer supported by manufacturers; meaning that spares are no longer available, except through salvaging of components through replacement of other similar units. The main factors that influence operating life are the manufacturer make or model, insulation medium and the corrosion zone.

Figure 9: Switching cubicle age profile



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 182, unpublished

The number of switching cubicle failures has reduced slightly since 2013/14, with approximately 9 per cent of all ground level switches currently being unable to be switched while energised.[18] Around nine failures have occurred each year over the last five years (0.12 per cent per annum).[19]

5.2.3.1 Replacement and refurbishment strategies for switching cubicles

The renewal/replacement strategy for switching cubicles is based on maintaining the long-term risk and performance across the population. It includes replacing many switching cubicles in the network that cannot be safely operated while energised. Limited refurbishment of switching cubicles is undertaken, with most makes/models replaced. Switching cubicle refurbishment significantly extends the operating life of some of the assets at a much lower cost than replacement but only a few models are able to be refurbished.

The management of switching cubicles is based around condition assessments and equipment performance and is transitioning from refurbish-or-replace based on condition to risk-based investment. Risk-based investment is based on maintaining the long-term risk and performance of these assets across the asset population. It

[18] SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 180

[19] Ibid

includes replacing many switching cubicles in the network that cannot be safely operated while energised. Approximately 100 switchgear units are planned to be either replaced or refurbished every year through to 2020, reflecting approximately 1.3 per cent per annum.[20]

5.2.3.2 Expected economic life of replaced or refurbished switching cubicles

The parent asset of switching cubicles with respect to replacement is the distribution underground feeder, however the switching cubicle itself is the parent asset with respect to refurbishment of components. Therefore, the expected life for replaced or refurbished switching cubicles needs to be determined separately.

For replaced switchgear, the economic life can fall under the same category as new switchgear with the Standard AER life. Replaced switchgear could also be stored for reuse should the underground asset be no longer required. Hence, we consider the Standard AER life of 55 years for replacements should apply with SL depreciation.

Refurbishment expenditure is only carried out on particular equipment. The remaining operating life with respect to depreciation on this expenditure would likely be much less than for new switchgear. Refurbishment works is conducted to achieve an expected maximum operating life of 45 years, and is typically conducted at mid- to end-of-life of cubicle switches. Therefore, we consider a revised economic life of 20 years is appropriate to apply to expenditure on refurbished switching cubicles with SL depreciation. Refurbishment expenditure on this asset category can be grouped into one new shorter life classification with a depreciation life of 25 years (Short-Life Line Assets).

5.2.4 Reclosers and sectionalisers

Reclosers and sectionalisers are specialised switchgear located on the overhead network. A recloser is similar to a circuit breaker connected to adjacent sections of overhead conductors in an electrical circuit. A sectionaliser is a switch which is used in conjunction with an associated recloser. They are positioned within the network to reduce the risk of damage from electrical faults and to improve the reliability of supply to customers.

There are approximately 1,394 reclosers installed across the network,[21] and the age profile of reclosers and sectionalisers is shown at Figure *10*. Approximately half of the recloser population is on the 11kV lines within the HV distribution network while over 80 per cent of sectionalisers are on the 19kV SWER lines.[22]

A significant proportion (approximately 92 per cent) of reclosers have been refurbished or installed in the last ten years[23] and a significant number of these reclosers have been refurbished over the last five years. The age profile of 676 sectionalisers installed across the network is relatively evenly distributed up to 50 years.

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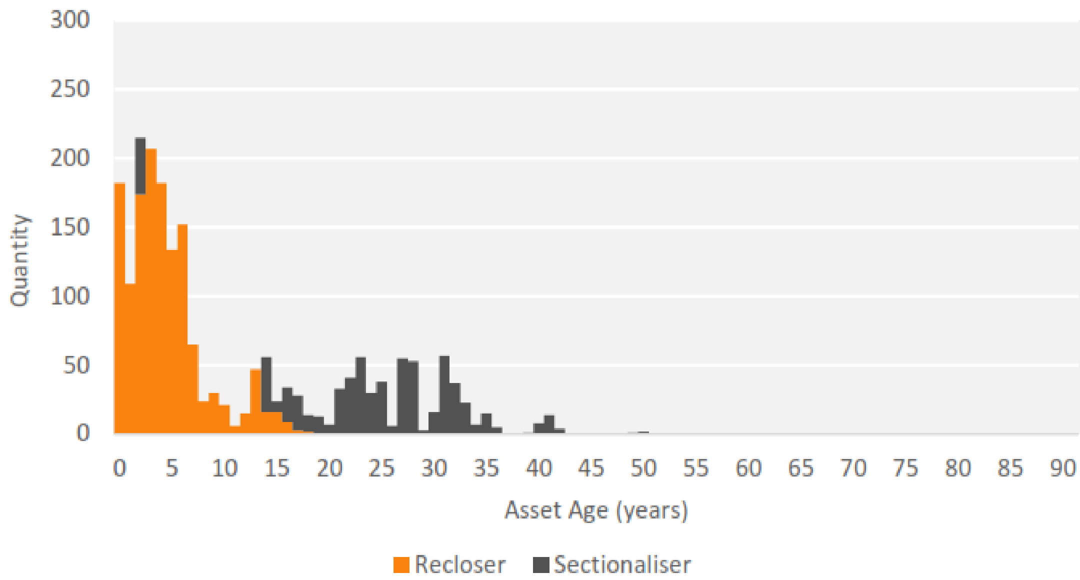
[20] SA Power Networks (2018) *Ground Level Switchgear Asset Plan 3.1.03 published December 2018*

[21] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 185, unpublished

[22] Ibid

[23] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 185, unpublished

Figure 10: Age profile of reclosers and sectionalisers



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187, unpublished

SA Power Networks state the expected operating life of hydraulic reclosers and sectionalisers to be approximately 45 years. The main factors that influence expected life of these assets are deterioration and/or failure due to corrosion, number of operations, and inherent and often undetectable manufacturing defects. The expected life of electronic controlled reclosers is much lower around 20 to 25 years as indicated through discussions with SA Power Networks.

The failure rate in the current population has trended downward for reclosers and remained stable for sectionalisers since 2010/11. Any reclosers or sectionalisers that have failed to operate during an outage event are repaired, refurbished or replaced. The failure rates in 2011 and 2017 for reclosers and sectionalisers are show in Table *5*.

Table 5: Number and rate of recloser and sectionaliser failures, 2011 and 2017

Asset failure	2011 (number, proportion)	2017 (number, proportion)
Recloser	105 (7.5%)	60 (4.3%)
Sectionaliser	25 (3.7%)	25 (3.7%)

Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187, unpublished

5.2.4.1 Refurbishment and replacement strategies for reclosers and sectionalisers

The key driver for refurbishment or replacement is where protection functionality requires upgrading to meet current standards. Hydraulic reclosers can be refurbished although their functionality and ability to interface with modern equipment is limited. Currently, all recloser tanks were refurbished within the last 20 years.[24]

The decision to refurbish or replace reclosers and sectionalisers considers several factors, including:

- Older electromechanical reclosers are refurbished where viable as this is more cost effective than replacement.
- Reclosers are replaced when they are unable to be refurbished, spares become obsolete, or if the units need to be provided with SCADA capability to enable remote monitoring and switching.
- Recloser controllers are typically replaced given most of the early electro-hydraulic controllers are obsolete and the high cost of refurbishment; or if the controllers are unable to be integrated into the SCADA environment.

We note that sectionalisers are unable to be refurbished and are therefore are replaced on failure and that modern electronic controlled reclosers are also typically replaced as a complete unit.

Approximately 230 refurbishment/replacements are planned for each year through to 2030, representing 11 per cent per annum of the population.[25] This reflects an average capital expenditure intervention every ten years for each recloser and sectionaliser.

5.2.4.2 Expected economic life of replaced or refurbished reclosers and sectionalisers

The parent asset for refurbished work on components is the recloser or sectionaliser itself and the “unit of property” is the distribution line for replacement consideration.

Replacement expenditure on reclosers or sectionalisers could be treated the same as new assets with a Standard AER life of 55 years. This is only valid on a weighted average approach to assets when economic lives fall around this average of 55 years.

The operating life of new electronic controlled reclosers is much lower at around 20 to 25 years. Given the planned number of interventions at 11 per cent per annum to 2030, we assume that about half of these will be

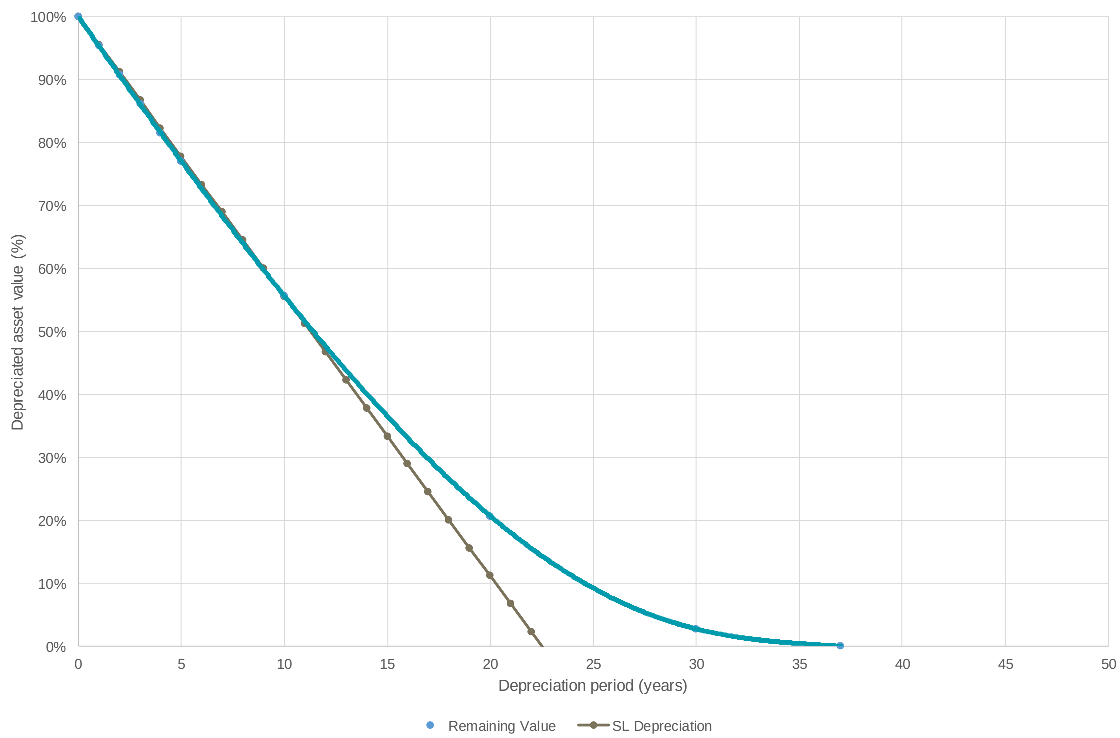
[24] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187, unpublished

[25] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187, unpublished

replacements and half will be refurbishments (based on the failure rates).[26] A failure rate of 5 per cent per annum would correspond to an average operating life of 20 years. Some of these reclosers and the older type reclosers may reach a greater operating life up to 35 years.

Figure *11* shows the remaining operating value of reclosers over time and how using SL depreciation with an economic life of 22.5 years would be applicable to new reclosers. New and refurbishment expenditure for this asset category could therefore be grouped into the one new shorter life classification with a depreciation life of 25 years (Short-Life Line Assets).

Figure 11: Reclosers – Remaining Operating Value and SL Depreciation



Source: GHD Advisory

Based on our discussions with SA Power Networks, we understand that the age profile of sectionalisers is relatively evenly distributed up to 50 years. The failure rate of 3.7 per cent per annum suggests the average operating life of sectionalisers will be around 27 years. Figure *12* shows the economic value appropriate for new sectionalisers to be 27 years.[27] New and refurbishment expenditure on this asset category can also be grouped into the one new shorter life classification with a depreciation life of 25 years (Short-Life Line Assets).

[26] This capital expenditure reflects both replacement and refurbishment expenditure. We have assumed an even split between these two expenditure categories.

[27] Based on our discussions with SA Power Networks

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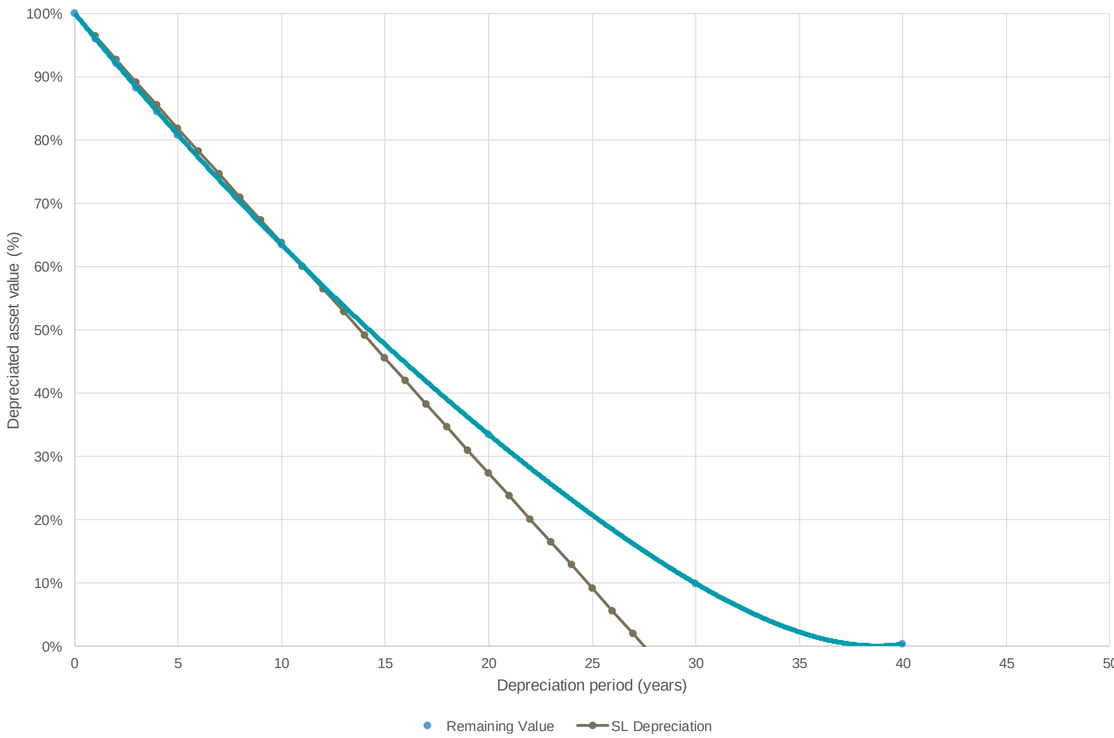
Figure 12: Sectionalisers – Remaining Operating Value and SL Depreciation



Source: GHD Advisory

Historically refurbishment work has been undertaken to reduce the failure rate of the switchgear and achieve longer operating lives for reclosers only.[28] The remaining operating life of a refurbished recloser will not be as long as a new recloser and we consider an appropriate life for depreciation purposes for refurbishment expenditure would be 10 years using SL depreciation. A separate 10 year asset class for recloser refurbishment could be created or the expenditure could be grouped into the 25 year short-life asset class.

[28] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187, unpublished

5.2.5 Pole Top Voltage Regulators and Capacitors

The assets are included under the "Non-category other sub-transmission system and distribution network assets" RIN asset class.

The 'other' sub-transmission assets include earthing systems, regulators and capacitors, and ancillary assets and have a range of functions within distribution network infrastructure, including:[29]

- *Earthing:* ensures that current is directed to earth rather than through the asset to minimise risks to staff, contractors and the public.
- *Regulators and capacitors:* ensures the line voltage is maintained within acceptable limits. These assets are being increasingly used to manage voltage fluctuations across the network with two-way power flows. There are 655 voltage regulator sites and 60 capacitor banks in the system.
- *Ancillary assets:* prevents unauthorised access to various sites, asset or infrastructure, allow staff and contractors access to SA Power Network's assets and assist network operations staff with locating faults (line fault indicators).

Regulators and capacitors are used to regulate the voltage for customers along distribution feeders. These include the installation and operation of 3 phase ground level voltage regulators, single phase pole mounted voltage regulators and pole mounted 11kV capacitor banks at locations along feeders. Only pole-mounted voltage regulators and pole-mounted capacitor banks are covered in this asset expenditure category.

In total there are approximately 650 pole mounted voltage regulators in the distribution network operating at 7.6kV, 11kV, 19kV and 33kV.[30] The majority (approximately 79 per cent) of the voltage regulators are installed on 11kV lines and 13 per cent of the voltage regulators are installed on 19kV lines. There are approximately 60 pole mounted capacitor banks on the distribution network.[31] All the pole mounted capacitor banks are 11kV capacitor banks.

The pole mounted voltage regulators and capacitors have exposed parts to weather elements and are therefore more prone to corrosion, the impacts of extreme weather conditions and third-party damage. Regular condition monitoring is required to identify deterioration of condition and defects that need to be risk assessed and rectified.

The typical asset operating life for voltage regulators and capacitor banks is 25 years, the actual life influenced by corrosion zone, load capacity, atmospheric pollution and fatigue.

There has been a long-term increasing trend in failures of voltage regulators due to corroding tanks and other causes. Analysis of the failure data has revealed that approximately 63 per cent of failures are due to tank corrosion. New design standard voltage regulators use stainless steel tanks and fittings, which are less susceptible to corrosion.

[29] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 191

[30] Ibid

[31] Ibid

5.2.5.1 Refurbishment or replacement strategies for Pole Top Voltage Regulators and Capacitors

In recent years, there has been no scheduled replacement or refurbishment program for voltage regulators as the current management strategy is to replace on failure. Pole-mounted voltage regulators are replaced like for like based on the condition assessments or because of a catastrophic failure. Pole-mounted capacitor banks are removed from service on failure as SA Power Networks has decided to cease new pole-mounted installations of capacitor banks in favour of large capacity banks installed in sub-stations.

The other assets in this RIN expenditure class are typically replaced on failure.

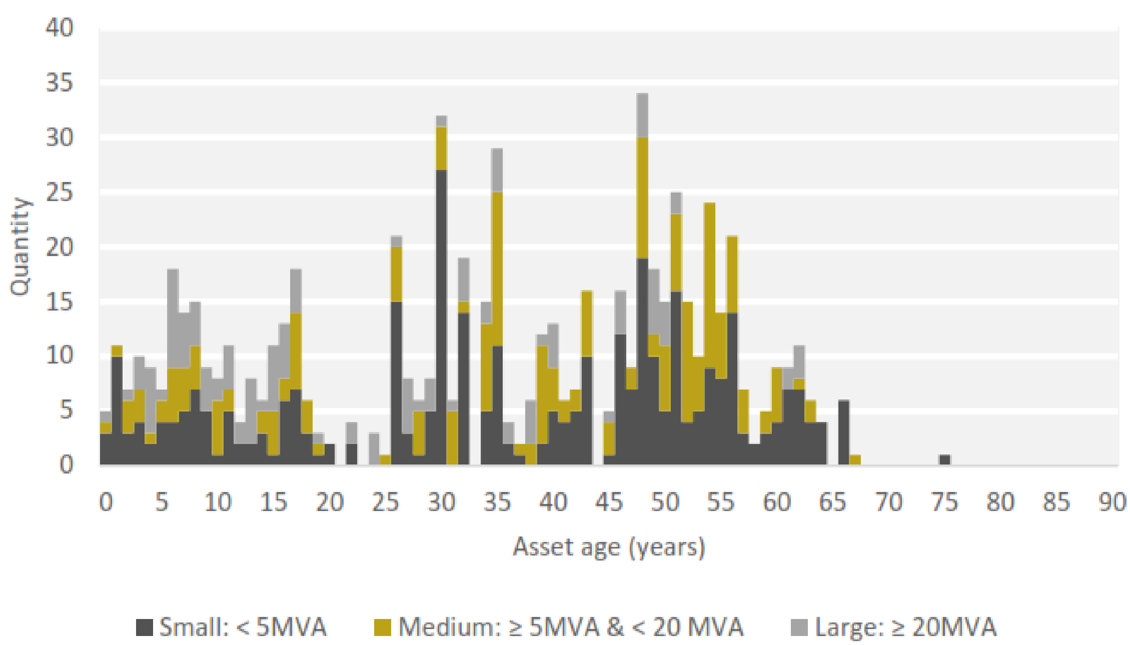
5.2.5.2 Expected economic life of Pole Top Voltage Regulators and Capacitors

The "unit of property" for these assets is the HV distribution line. As the typical asset operating life is 25 years, we therefore consider an economic life of 25 years for these assets using SL depreciation to be appropriate and in line with the economic life recommended for reclosers and sectionalisers. New expenditure for this asset category can therefore be grouped into the one new shorter life classification with a depreciation life of 25 years (Short-Life Line Assets).

5.2.6 Substation Power Transformers

Power transformers within zone substations provide voltage transformation and regulation of voltage in the HV network (sub-transmission system and HV distribution network). There are currently 682 substation power transformers in service with a significant proportion (approximately 40 per cent) in service for more than 45 years.[32] The age profile of SA Power Network's power transformers is shown in Figure *13*.

Figure 13: Age profile of power transformers



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 205, unpublished

[32] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 202

Over the period 2018 to 2023 around eight transformers (approximately 1.2 per cent per annum) will be unplanned replacement, and forecasts are that this rate will reduce to five transformers per year (0.7 per cent per annum) out to 2030. Approximately 55 per cent of these unplanned replacements are through transformer failures detected by condition monitoring prior to any major in-service failures.

5.2.6.1 Refurbishment or replacement strategies for power transformers

The plan for power transformers is to maintain an efficient mix of refurbishment and replacement works, with the combined effect resulting in approximately 1.4 per cent of the population (unplanned and planned) being replaced annually to 2030.[33] At the end of the end of the regulatory period in 2025 there will remain a significant number of large and medium transformers entering the high-risk range (greater than 60 years).

The power transformers asset strategies to 2030 include:

- Replacing failed and poor condition power transformers (primary strategy)
- Replacing high-risk Tyree 66/11kV 21MVA transformers (new strategy to address identified risk)
- Power transformer refurbishments – main tank and radiators (continuation of existing refurbishment program)
- Power transformer refurbishments – high-risk 66kV bushings and 11kV cable boxes (new strategy to address identified risk).

The power transformer refurbishment program includes replacement of high-risk 66kV bushings & 11kV cable boxes. Failure of transformer bushings and cable boxes present serious safety risks, as typical failure modes result in porcelain, insulating compound and metallic debris being propelled a considerable distance into the surrounding area and irreparable damage to the transformer.

The decision to refurbish or replace a substation transformer considers several factors. The key economic criteria are the cost of repair/refurbishment compared to the cost of new equipment and the confidence in the effectiveness of the refurbishment work.

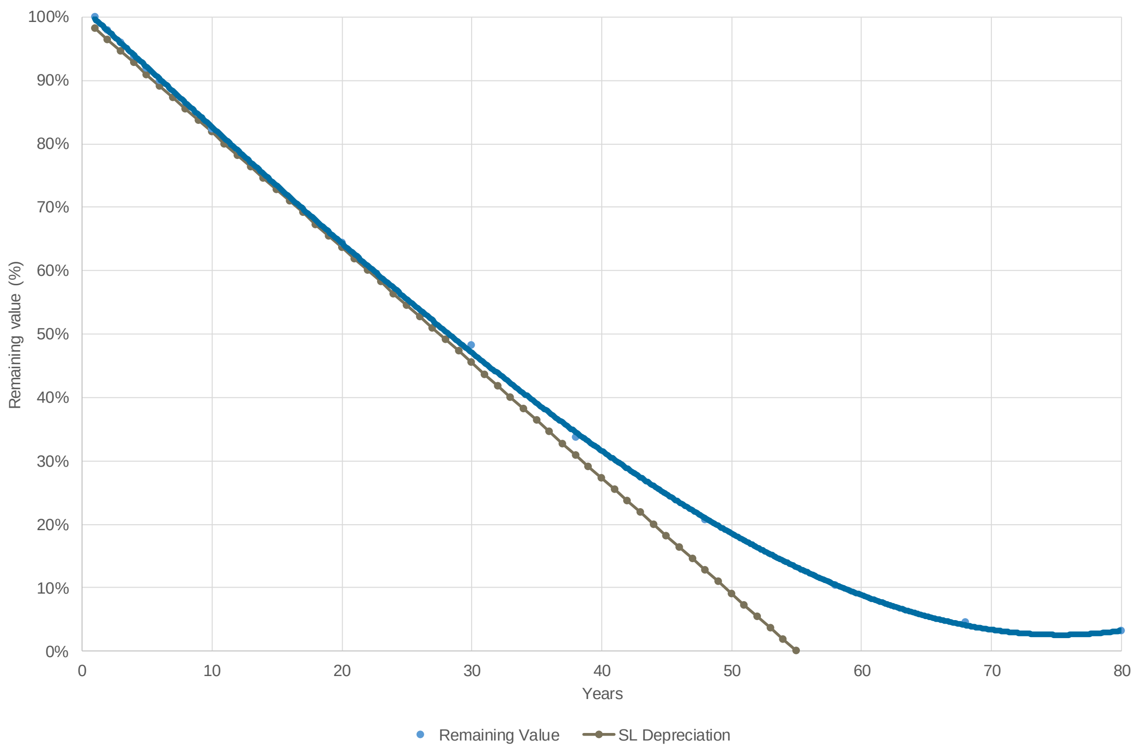
5.2.6.2 Expected economic life of replaced or refurbished power transformers

The parent asset for refurbishment of transformer components is the power transformer which is expected to be already past midlife when the refurbishment work is carried out. The parent asset together with the refurbished component assets will determine end of operating life for the refurbished asset. The expected life for depreciation purposes therefore needs to consider transformer replacements and the refurbishment expenditure separately.

For transformer replacements the “unit of property” is the substation in which the transformer operates and it is assumed that new transformer installed in a substation will continue operation until the end of its life and not be limited by the life of the substation. In any case, power transformers would be otherwise stored for future use on the network. For comparison purposes we show in Figure *14* that a SL depreciation with an economic life of 55 years would match the survival function for new power transformers, modelled using the reliability function for new power transformers. We consider the life of replaced transformers ought to be the same as new transformers, which is the Standard AER 45 years for substation assets.

[33] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 187

Figure 14: Power Transformers – Remaining Operating Value and SL Depreciation

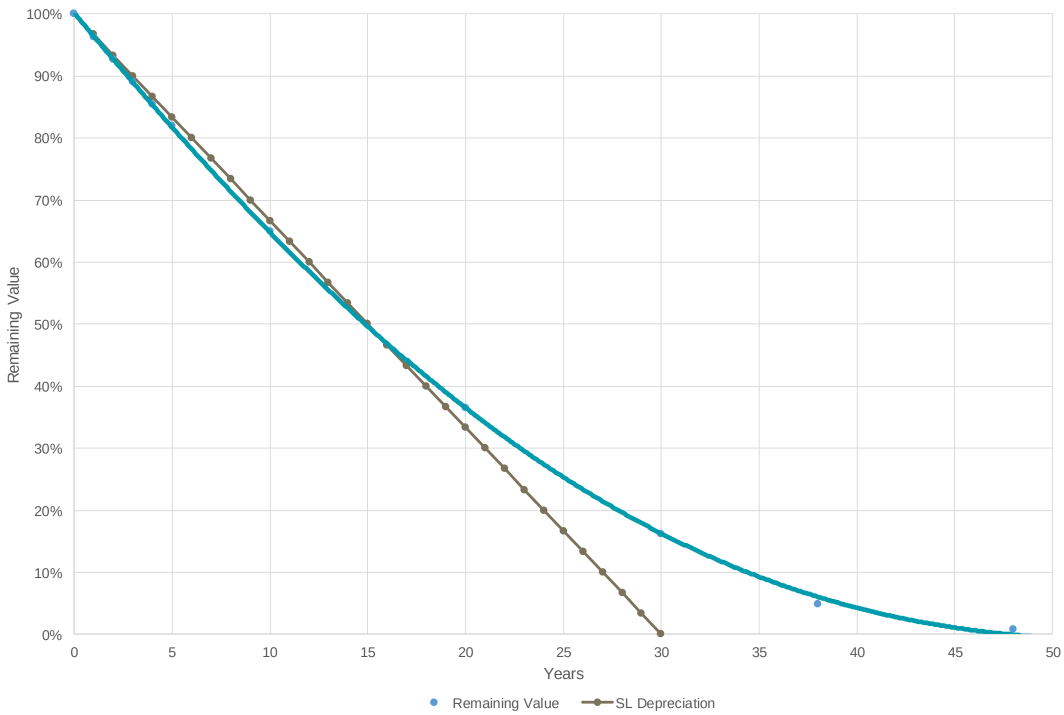


Source: GHD Advisory analysis

Refurbishment expenditure will typically be carried out at mid-life or later within the expected operating life of a power transformer. We modelled the risk of parent asset failure by using the remaining operating life of the parent asset and its reliability function. This is shown in Figure *15*. Our analysis indicates the effective economic life for power transformer refurbishment expenditure should be around 30 years with SL depreciation. The actual potential in-service operating life will range up to 50 years as shown from the modelling.

Refurbishment expenditure on power transformers can be grouped into a new shorter life classification with a depreciation life of 20 years (Short-Life Substation Assets).

Figure 15: Power transformer refurbishment – Remaining Operating Value and SL Depreciation



Source: GHD Advisory analysis

5.2.7 Substation circuit breakers and switchgear

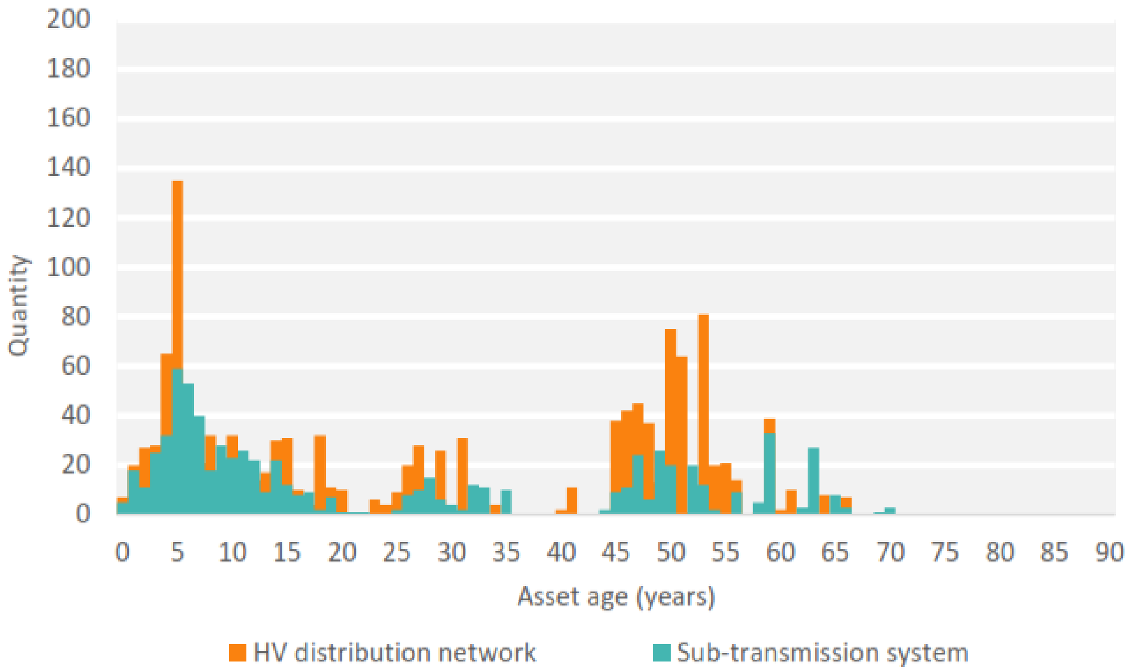
Circuit breakers act as controlled switching devices within zone substations and control the energisation of electricity distribution equipment. The safe and reliable operation of these assets is critical to network operation as they provide essential control and protection functionality necessary to maintain public safety and the ongoing reliable supply of electricity to our customers.

Currently there are 1,998 in service circuit breakers across the network with a significant proportion (approximately 37 per cent) in service for more than 45 years.[34] Distribution circuit breakers have a relatively equal split between old bulk oil circuit breakers and more modern vacuum types. For the sub-transmission system, older bulk oil and minimum oil circuit breakers represent a smaller proportion than the more modern circuit breaker types.

Figure *16* shows the age profile of circuit breakers. It illustrates that the majority of circuit breakers are less than 20 years old installed as a result of strong network growth (new substations and substation upgrades) over the period 2000 - 2015. Asset replacement programs over this period focused on populations of considerably aged (greater than 60 years) and poor condition outdoor 33kV and 66kV circuit breakers.

[34] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 211

Figure 16: Age profile of circuit breakers



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 214, unpublished

The expected operating life of a circuit breaker varies but for the current population is typically between 55 and 65 years. Factors that influence expected life are the switchgear installation environment, equipment design and operating duty (normal thermal/electrical service stresses and abnormal stresses from switching, lightning over-voltages and interruption of system faults).

SA Power Networks' focused investment from 2010/11 in the renewal of aged (1950s-era) HV indoor switchboard assets along with the replacement of many other asset types (such as civil works, HV cables and auxiliaries systems).

The number of circuit breaker failures has fluctuated between two and 11 units per annum from 2008 to 2017 and 0.1 per cent to 0.55 per cent, respectively.

5.2.7.1 Refurbishment or replacement strategies for circuit breakers

The high-level renewal/replacement strategy for circuit breakers is to maintain the long-term risk and performance across asset population as assets age and deteriorate in service provision. SA Power Networks' major substation circuit breaker strategies to 2030 include:

- Replacing indoor switchgear types in major metropolitan substations and the Adelaide CBD that no longer meet expectations for a safe and reliable service.
- Replacing failed and poor condition legacy outdoor circuit breaker types with no spare parts support and historically poor service performance.
- A series of circuit breaker replacement/refurbishment programs to address risks related to specific design flaws or performance issues that would otherwise lead to early equipment failure without specific intervention.

Delivery of the asset strategy will result in approximately 1.6 per cent of the asset population replaced annually to 2030 (approximately 28 per annum). The decision to refurbish or replace a circuit breaker considers the cost of repair/refurbishment vs cost of new equipment, and the confidence in the effectiveness of the refurbishment process. The replacement of 1.6 per cent per annum indicates the pro-active replacement of circuit breakers compared with the annual failure rate of between 0.1 per cent and 0.55 per cent.

5.2.7.2 Expected economic life of replaced or refurbished circuit breakers

The parent asset for refurbishment of circuit breaker components is the circuit breaker/switchboard/switchbay in which the circuit breaker components are installed. The parent asset together with the refurbished component assets will determine end of life for the refurbished asset. The expected life for depreciation purposes therefore needs to consider circuit breaker replacements and the refurbishment expenditure separately.

For replaced circuit breakers and switchgear, the life of the replaced unit should reflect that of a newly installed circuit breaker and switchgear. We consider the Standard AER life of 45 years for substations is appropriate for replaced circuit breakers.

Refurbishment expenditure is typically conducted mid-life or later on a circuit breaker or switchgear. We therefore consider an economic life of 20 years using SL depreciation is appropriate for circuit breakers and switchgear refurbishment expenditure which can be grouped into the one new shorter life classification (Short-Life Substation Assets).

5.2.8 Non-category substation assets

There are additional non-category substation assets that must be considered as part of this analysis. This asset groups consists of a number of different asset types, being:[35]

- *Lighting:* provides a safe place of work and site security. This asset includes substation indoor lighting (standard lights, emergency and exit lighting) and outdoor lighting (standard exterior lighting and floodlights).
- *Instrument transformers:* used with protection and metering devices to monitor the network quality of supply and detect faults. There are 356 voltage transformers and 717 current transformers in service in substations.
- *Surge arresters:* used to protect major substation equipment (transformers, regulators, cables, capacitors and circuit breakers) from the damaging effects of overvoltage due to lighting and switching surges. There are 2,268 substation surge arrestors installed.
- *Capacitor substation banks:* used to store energy for power factor adjustments by compensation of reactive loads on the distribution network which varies with load throughout the day. There are 111 capacitor banks in the system.
- *DC auxiliary supplies:* the substation direct current (DC) system provides a stable power supply for critical substation equipment independent of primary alternating current (AC) mains supply. There are 344 DC supplies in the system.
- *Earth grids:* provides earthing in the substation to protect equipment and safe operations. The earth grid asset category covers all types of earthing system and including earth stakes, buried conductors, earthed structures, connections, equipment conducting parts, cable screens and other components. There are 408 earth grids.

[35] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 219, unpublished

- *Buildings and structures:* the assets which house the protection, control, communications and switchgear equipment. Includes control buildings, firewalls, equipment support stands and footings, yard surface and stormwater management.
- *Airbreak disconnect switches:* these devices are used to visually and electrically isolate HV equipment or sections of the network for the purpose of safe access during maintenance, repair, upgrade or network operation. There are 2,929 switches in the system.
- *AC auxiliary supplies:* these assets load distribution of power to lights, power outlets, and critical ancillary systems on major primary plant. There are 341 AC auxiliary supplies.
- *Environment protection infrastructure:* these assets include permanent and interim oil containment bunds and substation noise control measures. There are 229 substation permanent oil containment solutions and 24 substation interim oil containment solutions, and 11 substation sites with sound control measures.
- *Safety infrastructure:* provides a safe place of work for substations and site security including substation fencing, and indoor and outdoor lighting.
- *Pipework switchyards:* An older compact overhead switchyard on a small footprint in country areas.
- Substation cables and cable terminations

5.2.8.1 Expected economic life of non-category substation assets

The capital expenditure for this category is a mix of targeted component replacements and refurbishments. The parent asset is the HV substation, where these asset components support the function of the substation. The expected life for depreciation purposes needs to consider separately the replacements and the refurbishment expenditure as follows:

- The life of assets replaced by new asset components is expected to be the same as expenditure in a new substations as they are generally separate independent units. We consider the Standard AER life of 45 years for these assets is appropriate.
- Refurbishment expenditure is carried out on particular equipment in this class. The remaining life for depreciation on this expenditure would likely be much less than replacement by new asset components. A reasonable assumption is that refurbishment will be carried out midlife. Hence, we consider a revised economic life of 20 years for expenditure on refurbishments of these assets is appropriate using SL depreciation which can be grouped into the one new shorter life classification (Short-Life Substation Assets).

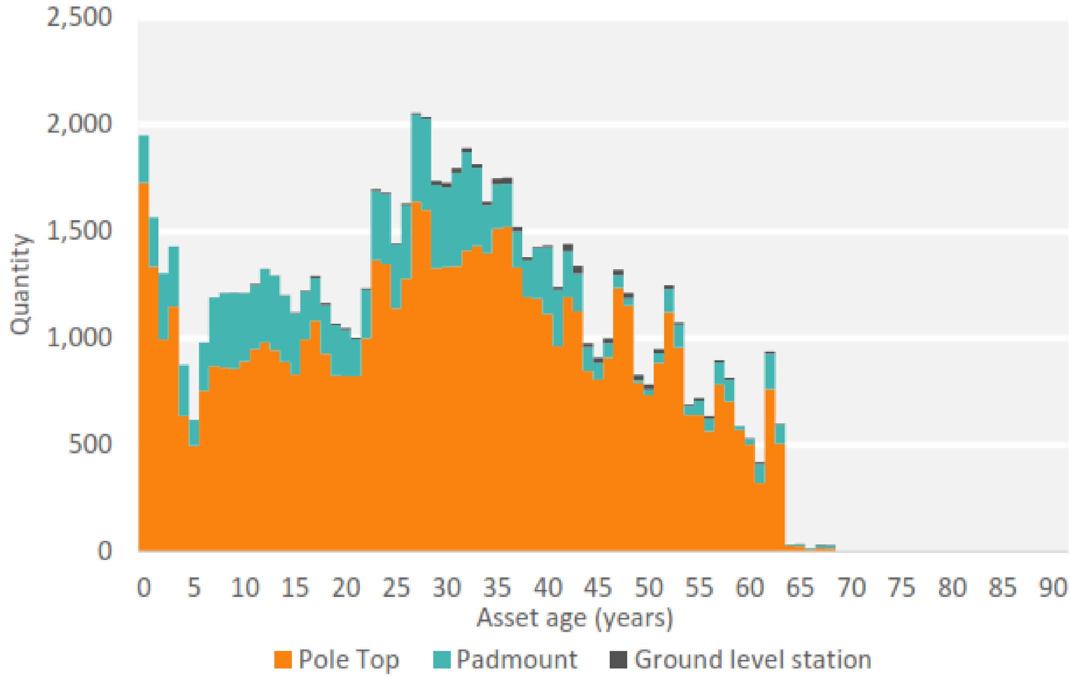
5.2.9 Distribution pole-top and ground level outdoor transformer refurbishments

Distribution transformers change the voltage of electricity for use at consumer voltage levels. They are installed overhead and mounted on poles (pole top), installed at ground level inside a cabinet/cubicle (padmount) or in enclosed chambers (ground level station).

There is currently 75,945 distribution transformers installed across the network and *Figure 17* shows the age profile of these transformers.[36] A significant proportion (approximately 47 per cent) of distribution transformers are between 30 and 60 years old. The expected operating life of distribution transformers is typically between 50 and 70 years. The main factors that influence expected life are corrosion zone, overloading of capacity and atmospheric pollution. Based on the existing age profile, there are 13 per cent of current distribution transformers are more than 50 years of age. This will increase to approximately 22 per cent by 2025.

[36] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 175, unpublished

Figure 17: Age profile of distribution transformers



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 175, unpublished

The number of failures on distribution transformers has remained relatively stable since 2011. The management of the transformers is largely based on renewal/replacement on failure due to the relatively low consequence of such events.[37]

5.2.9.1 Refurbishment and replacement strategies for distribution transformers

The renewal/replacement strategy for distribution transformers is based on risk management. As the consequence of a distribution transformer failure is low, the renewal strategy is based on prioritising for replacement transformers that have failed or identified to be in poor condition.

Refurbishments are conducted on the following transformer types, but represents less than 10 per cent of the total refurbishment and replacement expenditure on distribution transformers:

- Pole top transformers are only refurbished when they are unique in relation to voltages or have specific features that are required for a specific location.
- Padmount transformers are generally refurbished. Any corrosion of the cabinet is replaced as part of the refurbishment process.
- Any large and/or unique ground level distribution transformers (e.g. a specific physical size for certain space constrained locations) are generally refurbished.

The total number of transformers forecasted to be replaced to 2030 is around 480 each year (0.6 per cent per annum). Of these, approximately 40 per cent will be a result of the partly run-to-fail strategy.

[37] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 175, unpublished

5.2.9.2 Expected economic life of distribution transformers

The capital expenditure for this category is a mix of replacements with some refurbishments. The parent asset is the distribution voltage transformer for refurbished asset components which support the function of the transformer and housings and the "unit of property" is a distribution line with respect to replacements. The expected life for depreciation purposes needs to consider separately the replacements and the refurbishment expenditure as follows:

- The life of assets replaced by new transformers is expected to be the same as power transformer assets, as they are independent units and part of perpetual life distribution line assets. We consider the Standard AER life of 45 years is appropriate for asset replacements, consistent with new distribution transformer installations.
- Refurbishment expenditure is carried out only on particular transformer types. Therefore, it is likely that the remaining operating life would be much less than for new assets. A reasonable assumption is that refurbishment will be carried out mid-life. Hence, we consider a revised economic life of 20 years for expenditure on refurbishments of these assets is appropriate with SL depreciation.

5.2.10 Non-category substation assets

There are additional non-category substation assets that must be considered as part of this analysis. This asset groups consists of a number of different asset types, being:[38]

- *Lighting:* provides a safe place of work and site security. This asset includes substation indoor lighting (standard lights, emergency and exit lighting) and outdoor lighting (standard exterior lighting and floodlights).
- *Instrument transformers:* used with protection and metering devices to monitor the network quality of supply and detect faults. There are 356 voltage transformers and 717 current transformers in service in substations.
- *Surge arresters:* used to protect major substation equipment (transformers, regulators, cables, capacitors and circuit breakers) from the damaging effects of overvoltage due to lighting and switching surges. There are 2,268 substation surge arrestors installed.
- *Capacitor substation banks:* used to store energy for power factor adjustments by compensation of reactive loads on the distribution network which varies with load throughout the day. There are 111 capacitor banks in the system.
- *DC auxiliary supplies:* the substation direct current (DC) system provides a stable power supply for critical substation equipment independent of primary alternating current (AC) mains supply. There are 344 DC supplies in the system.
- *Earth grids:* provides earthing in the substation to protect equipment and safe operations. The earth grid asset category covers all types of earthing system and including earth stakes, buried conductors, earthed structures, connections, equipment conducting parts, cable screens and other components. There are 408 earth grids.
- *Buildings and structures:* the assets which house the protection, control, communications and switchgear equipment. Includes control buildings, firewalls, equipment support stands and footings, yard surface and stormwater management.
- *Airbreak disconnect switches:* these devices are used to visually and electrically isolate HV equipment or sections of the network for the purpose of safe access during maintenance, repair, upgrade or network operation. There are 2,929 switches in the system.

[38] Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 219, unpublished

- *AC auxiliary supplies:* these assets load distribution of power to lights, power outlets, and critical ancillary systems on major primary plant. There are 341 AC auxiliary supplies.
- *Environment protection infrastructure:* these assets include permanent and interim oil containment bunds and substation noise control measures. There are 229 substation permanent oil containment solutions and 24 substation interim oil containment solutions, and 11 substation sites with sound control measures.
- *Safety infrastructure:* provides a safe place of work for substations and site security including substation fencing, and indoor and outdoor lighting.
- *Pipework switchyards:* An older compact overhead switchyard on a small footprint in country areas.
- Substation cables and cable terminations

5.2.10.1 Expected economic life of non-category substation assets

The capital expenditure for this category is a mix of targeted component replacements and refurbishments. The parent asset is the HV substation, where these asset components support the function of the substation. The expected life for depreciation purposes needs to consider separately the replacements and the refurbishment expenditure as follows:

- The life of assets replaced by new asset components is expected to be the same as expenditure in a new substations as they are generally separate independent units. We consider the Standard AER life of 45 years for these assets is appropriate.
- Refurbishment expenditure is carried out on particular equipment in this class. The remaining life for depreciation on this expenditure would likely be much less than replacement by new asset components. A reasonable assumption is that refurbishment will be carried out midlife. Hence, we consider a revised economic life of 20 years for expenditure on refurbishments of these assets is appropriate.

5.2.11 Electronic Network Assets

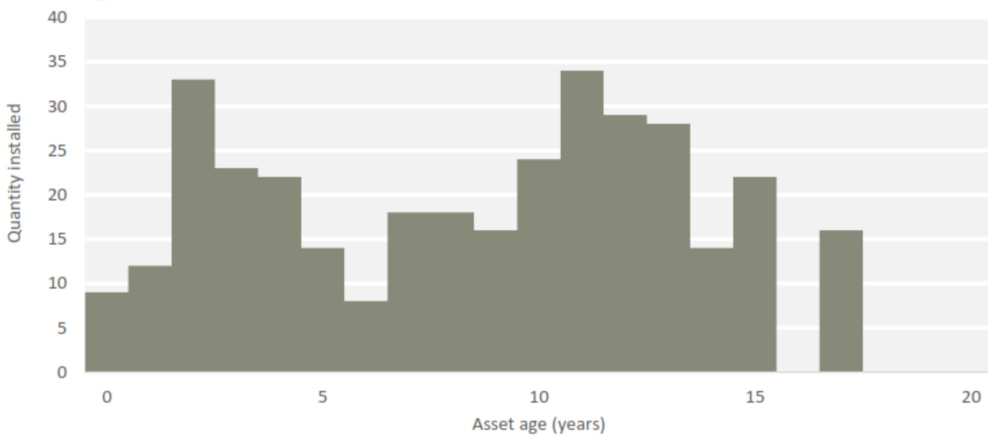
This type of asset includes electronic devices in substations such as secondary systems (SCADA, network control and protection relays), substation DC auxiliary supplies and condition monitoring devices; and electronic devices installed on HV and LV feeders such as low voltage meters and condition monitoring devices.

We have analysed this type of asset by reviewing SCADA and protection relays and based on industry experience we can extrapolate this assessment to all other electronic devices installed in substations and on distribution feeders.

Many of SA Power Network’s SCADA assets are largely electronic or computer based, their management is largely a fix on failure approach with no routine maintenance. However, as equipment and manufacturer support becomes obsolete in a shorter time relative to other network assets, replacement of other SCADA assets is targeted to ensure ongoing operability. Proactive targeted programs on RTUs and data concentrators are required to replace these assets that have exceeded their useful operating life, and maybe no longer supported by manufacturers, or are becoming increasingly difficult to maintain and support.

There are 340 RTUs across the network which have varying expected operating life, typically around 15 years. The main factors that influence expected life are environmental, for example temperature and moisture ingress. *Figure 18* shows the age profile of the RTUs.

Figure 18: Age profile of SCADA remote terminal units



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 226, unpublished

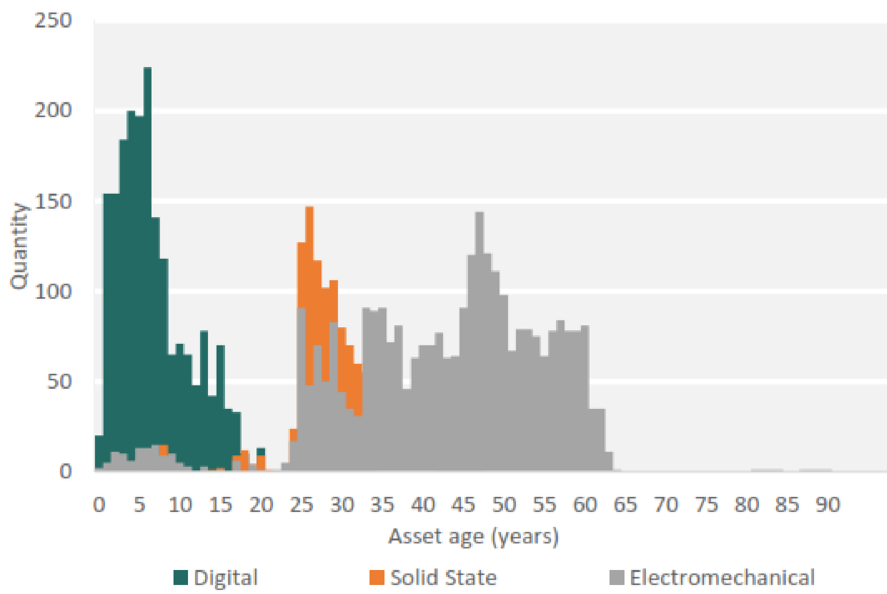
Figure 18 shows that a significant proportion (~42%) of RTUs are currently more than 10 years of age, and more than half will exceed the upper end of the expected life range by 2025 if no replacements are made. Data concentrators will also exceed their expected life of 15 years by 2020.

Protection relays and control assets in the HV network automatically protect personnel and the network in the event of fault conditions. There are 5,904 protection relays installed in substations. More than half of all protection relays are the older electromechanical type; the modern digital relays have the second largest population.

Figure 19 shows the age profile of the different protection relay types. A significant proportion (~63%) is more than 25 years of age. They are largely the electromechanical relays installed as part of the original network construction.

Protection relays 20–35 years of age are solid state relays; those less than 20 years are typically digital relays. The expected life for electromechanical, solid state and digital relays is 40-60 years, 20–35 years and 15–20 years respectively. Protection relays therefore can be separated into two different asset life categories. The electromechanical relays have economic lives commensurate with the Standard AER life and electronic relays (solid state and digital) will have a lower asset life due to a number of factors outlined in the following section.

Figure 19: Age profile of protection relays



Source: SA Power Networks (2018) *Power Asset Management Plan – Manual no. 16,* pg 232, unpublished

The expected life for all electronic based devices installed in substations or on feeders is expected to have the same operating life profiles as SCADA and protection relays. The less mature developed the devices are the device life would be expected to be shorter and similarly for devices installed in less controlled operating environments. Typical operating life would range from 15 to 20 years, with most either failed or replaced by 20 years of age.

5.2.11.1 New and replacement strategies for network electronic assets

The strategy for new SCADA and network control assets includes extending SCADA functionality in rural substations and 11kV and 19kV switches on the HV distribution network to align visibility and functionality with similar switches in the metropolitan Adelaide region.

The renewal/replacement strategy for RTUs and data concentrators include:

- RTU replacements: More than half of the RTUs will exceed their expected life of 15 years by 2025, and are proposed to be replaced with modern day equivalent RTUs. Newer RTUs that randomly fail will also be replaced on failure.
- Data concentrators: Nine data concentrators will exceed their expected life of 15 years by 2025. All data concentrators are proposed to be replaced with modern day equivalent assets by 2025.

Most new protection relays installed will be digital relays, the key consideration being the functionality provided by these relays for substation and network reconfiguration and automation capability.

The renewal/replacement strategy for protection relays is based on retaining the long-term performance across the protection relay population at acceptable risk levels. Electromechanical protection relays are refurbished under maintenance programs where possible using purchased components or spares from previously replaced units. Refurbishment of electromechanical protection relays significantly extends their life at a much lower cost than complete replacement. Where these relays are replaced, digital relays are typically installed.

SA Power Networks indicate that based on protection relay history compiled to date, it is anticipated electronic relay failures will increase in the future with increasing numbers of digital relays nearing 15 years of age and their expected operating life.

Replacement of protection relays can be is undertaken for other reasons, such as unavailability of spares and/or manufacturer support (obsolescence), the model shows endemic failure issues, or the relays are not able to provide the required functions prior to the end of their life.

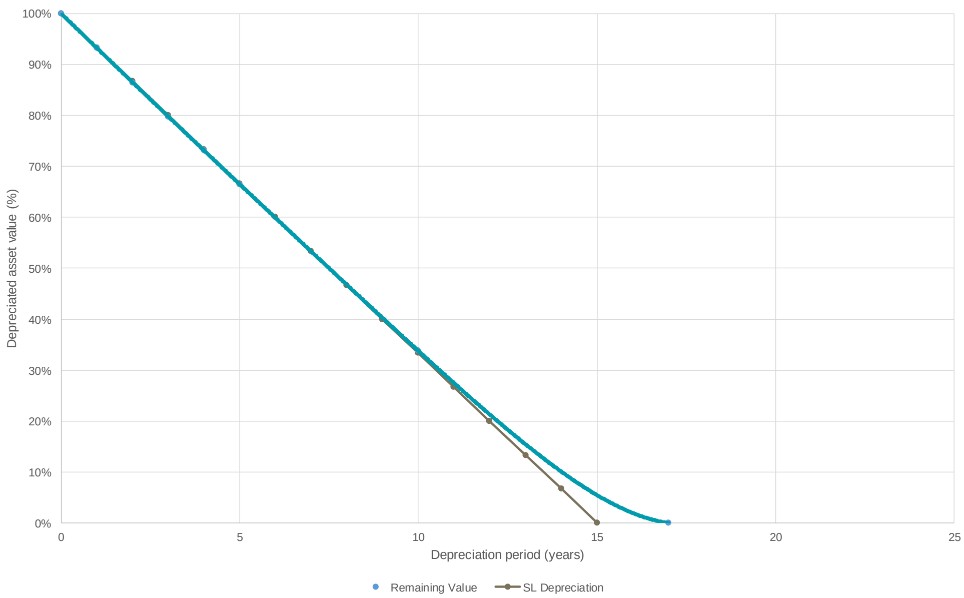
All electronic based devices installed in substations or on feeders should have similar end of life strategies applied, either replace before the risk of failure is too high or run to fail for less critical electronic devices.

5.2.11.2 Expected economic life of Electronic Network Assets

The “unit of property” with respect to devices which are replaced with an electronic network asset (eg. digital protection relays) will a substation or a distribution feeder or the like. The replacement electronic based device will have the same economic life as new devices as the “unit of property” asset is assumed to have a perpetual life, and in other cases the life of electronic devices is shorter than the economic life of substations and distribution feeders.

We have used a reliability function for digital protection relays with 0.5% pa failure rate, increasing after 10 years with a replacement program from year 14 to year 18. The remaining operating function shows that with a replacement on age and low failure rate during useable life that the economic life will equal the replacement age. *Figure 20* shows that a SL depreciation with an economic life of 15 years would match remaining operating value. Based on our experience and view that all electronic devices would display similar characteristics as protection relays, we consider the appropriate economic life for new electronic network assets should be 15 years for depreciation purposes.

Figure 20: Electronic Network Assets – Remaining Operating Value and SL Depreciation



Source: GHD Advisory analysis

6. Conclusions

Key finding 1: The current AER-approved lives (Standard AER lives)[39] should generally apply to replacement assets[40] as electricity assets are intended to have a perpetual life

Assets that are replaced on the network (such as lines, substations and communications) are typically installed with the intent to maintain the life of a distribution line or substation in perpetuity. Under this scenario, it is appropriate that the Standard AER lives apply to these new assets.

Key finding 2: Refurbished Assets[2] - the economic life for depreciation for refurbishing asset components is shorter than that of a new parent asset, and is typically around half of the economic life of a new asset.

The decision to refurbish an asset rather than replace it is based on whether the costs will be minimised over the remaining operating life of the asset, having regard to any increased risk of failure of a refurbished asset when compared to a new asset. Examples of this include the plating of stobie poles and the refurbishment of bushings, windings and tapchargers on power transformers.

Refurbishment expenditure on an asset component is aimed at maintaining or extending the life of the parent asset. These interventions typically occur between mid and near end-of-life of the parent asset. Hence, we find that the appropriate period for depreciating refurbishment expenditure on an asset component is shorter than that of its parent asset.

Key finding 3: Electronic Network Assets – Electronic type assets installed on distribution lines and in substations have a much lower economic life than the standard AER lives.

Our findings show that Electronic Network Assets which includes electronic devices installed in substations such as SCADA devices and protection relays, and electronic devices installed on HV and LV feeders, have operating lives often determined by the inability to support ongoing maintenance as well increasing failure rates requiring replacement programs around 15 years of age. This is distinctly different than the standard AER life for distribution lines and substations and therefore we recommend a separate asset live for depreciation treatment.

Summary of key findings by asset category

We initially analysed replacement or refurbishment expenditure on an asset by asset basis to first determine an appropriate economic life aligned to the remaining operating value of each asset type.

This analysis led to the conclusion that generally depreciation on expenditure for asset replacements can be treated the same as new assets and that depreciation on expenditure for refurbished assets is shorter than that of a new parent asset, and is typically around half of the economic life of a new asset. While some assets indicated an assessed economic life some higher and some lower, it is recommended to group refurbishment expenditure on assets belonging to sub-transmission and distribution lines to one new shorter life classification,

[39] Standard lives are set out in the AER's "Final Decision SA Power Networks determination 2015-16 to 2019-20 Attachment 5 – Regulatory depreciation", October 2015

[40] AER, DRAFT Industry practice application note – Asset replacement planning, 2018

and similarly refurbishment expenditure on assets belonging to substations to a second new shorter life classification (on a weighted average type approach similar to new assets).

During the review of replacement and refurbishment expenditure, it was also found that new electro-mechanical type assets installed on lines (eg. reclosers, sectionalisers and voltage regulators) had a shorter economic life than the Standard AER life of 55 years. The expenditure for both new and replacement equipment of this type can be grouped into the new 25 year short-life asset class. Refurbishment expenditure, which is only relevant for reclosers, could either have a separate 10 year asset class or could also be grouped into the 25 year short-life asset class.

A third and separate category is recommended for electronic network assets installed within substations and on HV and LV feeders with a life of 15 years, and for both new and replacement devices.

A summary of the asset-by-asset evaluation for depreciation treatment is shown in *Table 6.* We consider adopting a shorter asset life using SL depreciation methodology to a range of asset classes is the most appropriate treatment for SA Power Networks' network distribution assets.

Table 6: Findings by asset category

Expenditure Category	Asset-by-asset economic life assessment		GHD recommended depreciation lives		Comments
	Replacements	Refurbishments	Replacements	Refurbishments	
Stobie poles	55 years	30 years	55 years	25 years	Retain asset replacements the same as new assets. Group refurbishment for this asset category with all line type refurbishments into one common 25 year short-life asset class.
Pole top structures	45 years	n/a	55 years	n/a	Retain asset replacements the same as new assets.
Switching cubicles	45 years	20 years	55 years	25 years	Retain asset replacements the same as new assets. Group refurbishment for this asset category into the one common 25 year short-life asset class.
Reclosers and sectionalisers	25 years	10 years	25 years	10 years	Group new and replacement expenditure for this asset category into the one common 25 year short-life asset class. Create a separate 10 year asset class for recloser refurbishment or group into the one common 25 year short-life asset class.

Expenditure Category	Asset-by-asset economic life assessment		GHD recommended depreciation lives		Comments
	Replacements	Refurbishments	Replacements	Refurbishments	
Non-Category sub-transmission and distribution lines[41]	25 years	n/a	25 years	n/a	Group new and replacement expenditure for this asset category into the one common 25 year short-life asset class.
Distribution transformers	55 years	25 years	45 years	20 years	Retain asset replacements the same as new assets. Group refurbishment for this asset category will all substation type refurbishments into one common 20 year short-life asset class.
Substation power transformers	55 years	25 years	45 years	20 years	Retain asset replacements the same as new assets. Group refurbishment for this asset category into the one common 20 year short-life asset class.
Substation circuit breakers and switch gear	45 years	20 years	45 years	20 years	Asset replacements the same as new assets. Group refurbishment for this asset category into the one common 20 year short-life asset class.
Non Category Substations	45 years	20 years	45 years	20 years	Asset replacements the same as new assets. Group refurbishment for this asset category into the one common 20 year short-life asset class.
Electronic Network Assets	15 years	n/a	15 years	n/a	Group new electronic device assets in substations and on lines under a common new short-life asset class. Refurbishment of electronic devices is not viable.

Source: GHD Advisory

[41] Other sub-transmission system and distribution network assets (pole top voltage regulators and pole top capacitors)

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GHD Advisory