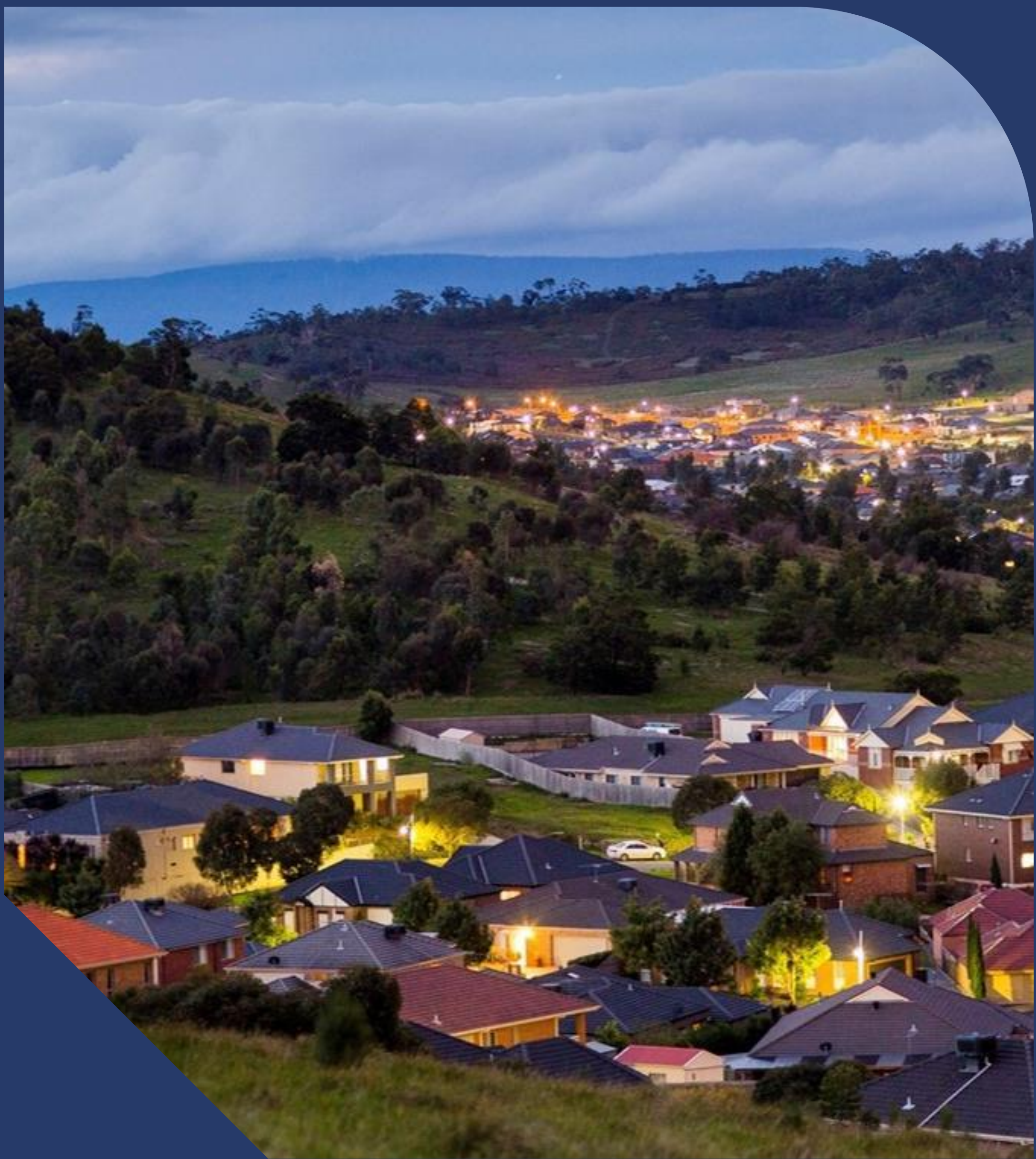
AusNet

# AMS 10-24 Asset Renewal Planning Guide

Monday, 10 November 2025



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# 1. Purpose

This Asset Renewal Planning Guideline provides a framework for AusNet Services' asset renewal planning for the Victorian electricity transmission network.

# 2. Scope

This Asset Renewal Planning Guideline covers AusNet Services' regulated electricity transmission assets operating across Victoria, including:

- Transmission lines, power cables and associated easements and access tracks;
- Terminal stations, switching stations, communication stations and depots including associated electrical plant, buildings and civil infrastructure;
- Protection, control, metering and communications equipment;
- Related functions and facilities such as spares, maintenance and test equipment; and Asset management processes and systems such as System Control and Data Acquisition (SCADA) and asset management information systems (including SAP).

This guide excludes the assets and infrastructure owned by:

- Generators;
- Connected customers; and
- Other companies providing transmission services within Victoria.

# 3. Background

AusNet Services' electricity transmission network serves approximately 7 million Victorians with more than 6,600 kilometres of transmission lines. The network is centrally located among Australia's five eastern states that form the National Electricity Market (NEM), providing key connections between South Australia, New South Wales and Tasmania's electricity transmission networks. The network served a peak operational demand of 10,576 MW on 29 January 2009, and a minimum operational demand of 1504 MW on 1 January 2025.

AusNet Services is committed to delivering safe and reliable network services by investing in network upgrades and maintenance, and by achieving the objectives set for the provision of network services through pricing determinations and other regulatory instruments.

**Figure 3-1: AusNet Services' Electricity Transmission Network**

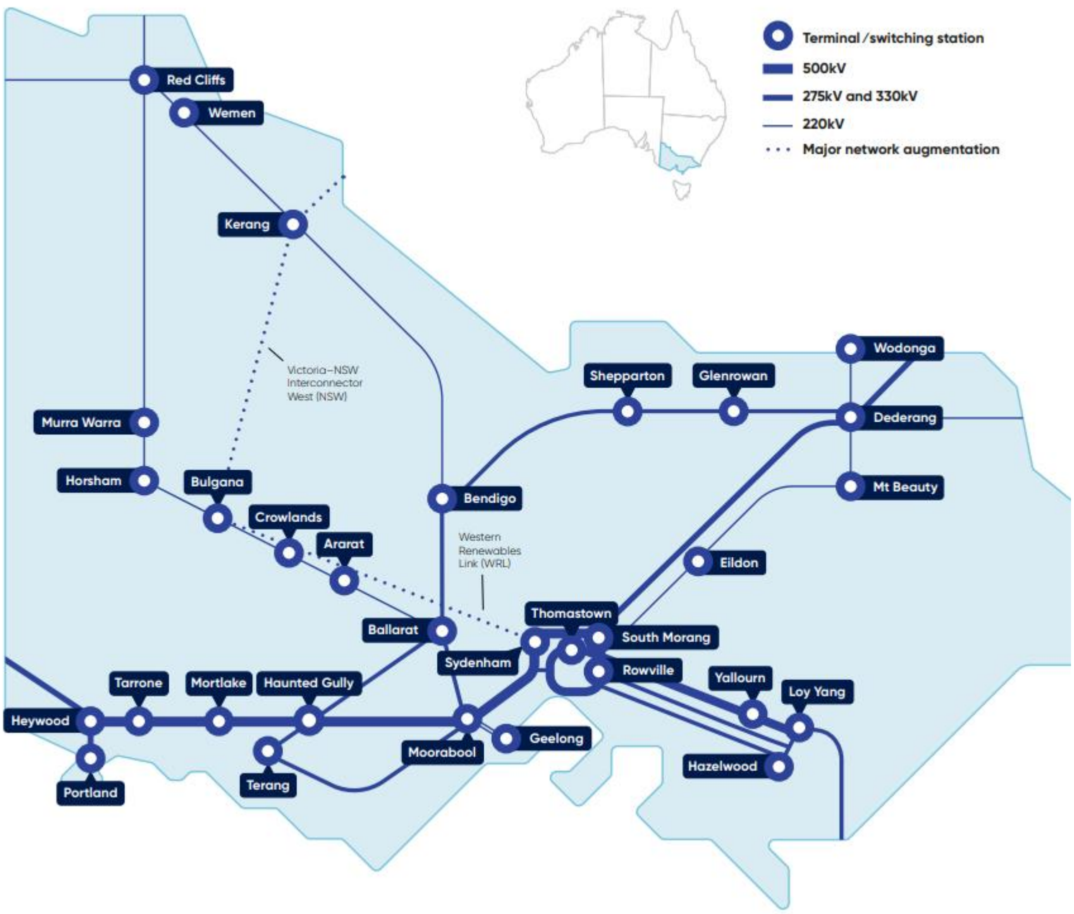



**Figure 3-2**

# 4. Victorian Planning Framework

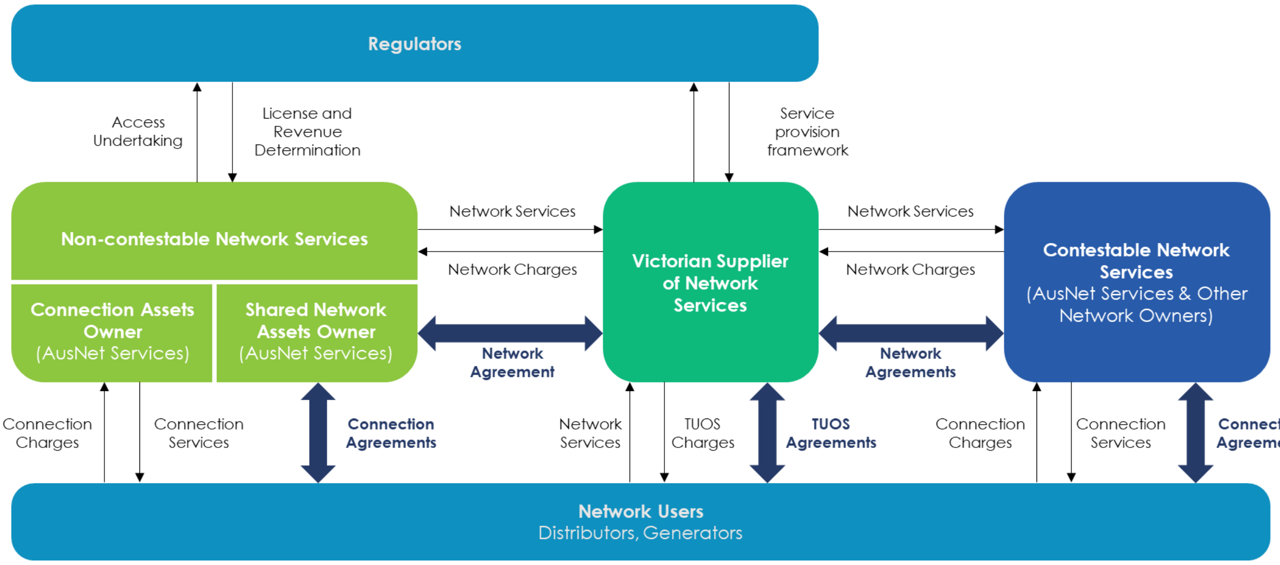
Responsibility for planning of transmission network services in Victoria is shared by the following three different parties:

- The jurisdictional planner, is the body solely responsible for planning the shared transmission network[1] and procuring network support and shared network augmentations, VicGrid, as of the 1 November 2025;
- the asset owner, AusNet Services (Transmission) Ltd (referred to in this document as AusNet Services); and
- the transmission customers (distribution companies, generation companies and directly-connected customers), which are responsible for planning and directing the augmentation of their respective transmission connection facilities.

In Victoria, the transmission network augmentation planning functions are separated from the functions of ownership and operation. These arrangements differ from other states in Australia, where planning and responsibility for augmentation remains integrated with the incumbent transmission company (although independent planning oversight occurs in South Australia). The relationships between these parties and the Regulators are shown in Figure 4-1.

AusNet Services primary responsibilities therefore are in relation to the operation and asset management of its Victorian transmission network. AusNet Services plans and provides for the renewal of network assets in a joint planning process, with VicGrid, which achieves an integrated network planning approach for the Victorian network.

**Figure 4-1: Regulatory and commercial relationships**




Source: AusNet Services

Note that the "Victorian Supplier of Network Services" is currently VicGrid as of 1 November 2025.

[1] The shared transmission network is the main extra high voltage network that provides or potentially provides supply to more than a single connected party with lines and tie transformers generally rated above 220 kV.

# 5. Economic and Technical Regulation

The National Electricity Law (NEL) contains two overarching principles that the AER applies when performing its economic regulatory functions or powers. Under section 16(1)(a) of the NEL, the AER must act in a manner that will, or is likely to, contribute to the achievement of the National Electricity Objective (NEO). The NEO is set out in section 7 of the NEL as follows:

The objective of this law is to promote efficient investment in, and efficient operation and use of, electricity services for the long term interest of consumers of electricity with respect to:

a) price, quality, safety, reliability and security of supply of electricity; and
b) the reliability, safety and security of the national electricity system; and
c) the achievement of targets set by a participating jurisdiction:
    i) for reducing Australia's greenhouse gas emissions; or
    ii) that are likely to contribute to reducing Australia's greenhouse gas emissions.

The AER must also take into account the revenue and pricing principles set out in the NEL when making a transmission determination[2]. Amongst other things, these principles require a TNSP to be provided with an opportunity to recover at least its efficient costs, and provided with effective incentives in order to promote economic efficiency.

The Electricity Safety Act in Victoria requires AusNet Services to "design, construct, operate, maintain and decommission its supply network to minimise as far as practicable, the hazards and risks to the safety of any person arising from the supply network"[3].

The Occupational Health and Safety Act in Victoria requires AusNet Services to "so far as is reasonably practicable, provide and maintain for employees of the employer a working environment that is safe and without risks to health"[4]

The National Electricity Rules (via clause 5.16) requires transmission network service providers to conduct a Regulatory Investment Test for Transmission (RIT-T) for both network augmentation projects and asset replacement projects where the most expensive credible option is valued at more than $8 M[5].

[2] NEL, clause 16(2)(a)(i). The revenue and pricing principles are set out in section 7A of the NEL.
[3] Electricity Safety Act 1998 (Vic), section 98(a)
[4] Occupational Health and safety Act 2004 (Vic) Section 21 (1)
[5] Australian Energy Regulator, 2024 RIT and APR cost thresholds review, Final determination (November 2024), effective 1 Jan 2025.

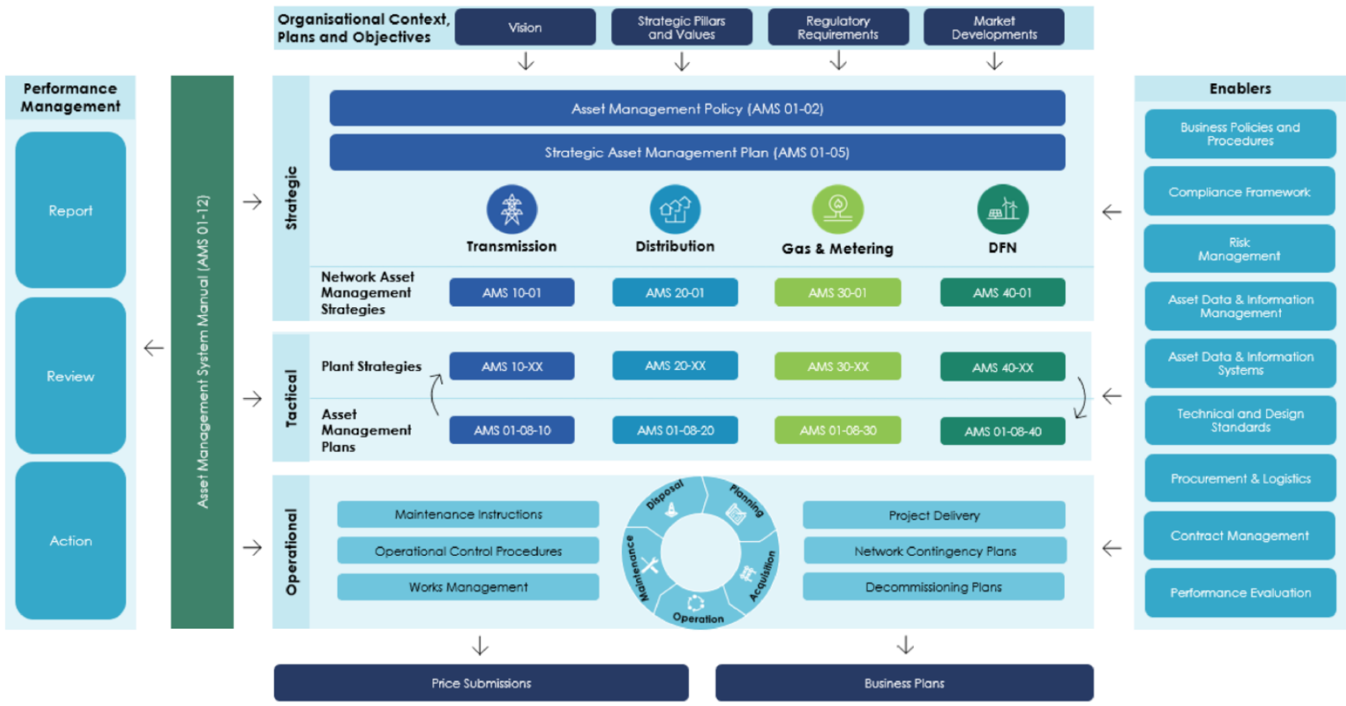
# 6. Asset Management Framework and Strategy

AusNet Services' renewal decisions are made using our asset management framework and systems. The asset management system contains an asset management policy statement, strategic asset management plan, asset management objectives and a detailed suite of asset management strategies. The asset management policy acknowledges the company's purpose and directs the content and implementation of asset management strategies, objectives, and plans.

The development of asset management strategies is informed by an assessment of the external business environment, the corporate business and financial plans and responses to stakeholder engagement, which incorporates customer, generator, regulator, shareholder, and government views.

AusNet Services' Asset Management Framework is illustrated in Figure 6-1.

**Figure 6-1: AusNet Services' Asset Management Framework**




AusNet Services' Asset Management Policy[6] directs the content and implementation of asset management strategies, objectives and plans for AusNet Services' energy delivery networks. It guides employees, contractors, suppliers and delegates in making informed asset management decisions to achieve AusNet Services' corporate business purpose of: "Empowering communities and their energy future".

Asset Management Strategy AMS 10-01[7] documents AusNet Services' holistic approach to the management of electricity transmission assets under AusNet Services' stewardship and establishes the linkages among the underpinning detailed strategies, processes and plans. The approach seeks to deliver optimal electricity transmission network performance at efficient cost by ensuring that all decisions to replace or maintain network assets are economically justified.

[6] AMS 01-02 AusNet Services' Asset Management Policy (November 2024)
[7] AMS 10-01 AusNet Services' Electricity Transmission Asset Management Strategy (October 2025)

# 7. Asset Renewal Strategy

# 7.1. Asset Renewal Objectives

The objective of asset renewal is to achieve sustainable outcomes in:

- Safety of customers, the community and workers
- Quality, reliability and security of supply of electricity transmission services
- Compliance with codes, licences, contracts, industry standards and obligations
- Minimising total life cycle costs through the consideration of capital costs, operational costs, retirement costs, operational risk costs and costs to achieve jurisdictional greenhouse gas reduction targets
- Stabilising volatility of renewal works and associated material, skill and revenue requirements
- Minimising project delivery risks and the potential impact of renewal works on network availability, market participants and connected parties
- Bringing assets to the latest industry standards

# 7.2. Asset Renewal Criteria and Drivers

The key drivers for transmission asset renewal decisions are discussed in this section.

## 7.2.1. Compliance

AusNet's network and asset management practice are required to comply with all relevant laws, regulations, codes, and binding standards. This includes obligations relating to worker safety and network safety which stipulate the approach to managing safety risk.

Under the Occupational Health and Safety Act, AusNet is required to, so far as is reasonably practicable, eliminate or reduce risks to health and safety of its employees and the broader community. Under the Electricity Safety Act, AusNet is required to operate its electricity transmission network in a way that minimises as far as practicable the hazards and risks to the safety of any person arising from the supply network, the hazards and risks of damage to the property of any person arising from the supply network and the hazards and risks of damage to the property of any person arising from the supply network.

These obligations require AusNet to have regard to safety hazards and the likelihood and consequences of them occurring, and consider the availability and suitability of ways to eliminate or mitigate safety hazards in managing and asset management.

## 7.2.2. Network Performance

If equipment performance trends indicate that contractual performance requirements (relating to the respective codes and licences) will not be met, or will be unreasonably compromised, or that the existing service provision is no longer efficient, planned (proactive) renewal is investigated.

Maintenance, refurbishment and replacement plans are developed using an underlying strategy of condition-based remediation. This strategy uses risk management principles that take into account criticality, reliability and the prudence of adopting a particular course of action.

The risk and consequence of plant failure, including unserved load, generation constraints and reduced network performance are assessed as part of each asset management decision. Asset management is also balanced with a longer-term perspective on capital and network access requirements and indicators such as the estimated remaining life of the assets.

While assets are generally managed as a discrete 'fleet', each decision to replace or refurbish items of plant is taken on a case-by-case basis.

When assets are unable to operate at their full rating, this tends to place operational restrictions on network configuration and capability and can result in poor utilisation of associated major plant (for example power transformers). To address this, planned replacement of minor plant items (for example, disconnectors) is often combined with other plans (like AEMO augmentation plans) to optimise network capability and node to node load transfers.

## 7.2.3. Probability of Asset Failure

An asset is deemed to have failed when it does not meet the functional requirements for which it was acquired. AusNet Services' strategy and approach to calculation of asset Probability of Failure (PoF), as described in Section 4 of AMS 01-09[8], is summarised in this section.

### 7.2.3.1. Probability of Failure of Existing Assets

Both quantitative and qualitative analysis is used to assess the condition, determine the probability of failure and estimate the remaining life of existing assets.

Table 7-1 lists the categories taken into consideration when determining the likelihood of an asset failure. Asset physical condition is a direct measure of the state of the asset whereas utilisation and location influence the rate at which an asset is projected to deteriorate.

**Table 7-1: Assessment Categories for Probability of Failure Estimate**

| Category | Description | Data Source |
|---|---|---|
| **Asset Life** | Ratio of current service age to normal expected life | Design, maintenance records |
| **Asset utilisation/duty factor** | Capacity, loading, strength, number of operations | Maintenance records |
| **Location factor** | Geographical climate, corrosivity, environment | Design/operations |
| **Asset physical condition** | Observed condition, measured conditions | Inspections/testing |

A conditional PoF of an asset (the probability that the asset will fail within 12 months from the current point in time) is determined using either Machine Learning models or health score calculations, based on data representing the four categories in Table 7-1. The conditional PoF values are then extrapolated under the assumption that the PoF increases over time as assets degrade. Asset physical condition is a key driver of asset renewal activities. As equipment condition deteriorates, its design safety margins and performance can gradually decline below network operating requirements. Assets require a margin which allows them to operate during foreseeable abnormal network operating conditions, caused by network faults, surges, plant outages, and high ambient temperatures. This margin determines asset reliability and security.

Failure Modes Effect Analysis (FMEA) is the principal technique used to gain knowledge about the modes and rates of deterioration of each asset type. Benchmarking with other transmission network service providers and liaison through industry associations such as CIGRE brings additional data, experience and insight. Using this knowledge, condition is assessed through a wide range of activities including online condition monitoring, regular inspections, planned maintenance and issue-focussed testing.

PoF values for a fleet of assets aid comprehension of the extent and the rate of deterioration. The analysis also provides input to asset risk models, which are used to compare future risk forecasts with historical and current risk positions.

### 7.2.3.2. Probability of Failure of New Assets

New assets are considered to have a remaining life of greater than 80% of normal expected life. As such, the failure rates of new assets are calculated using the interval 0% to 20% of Weibull characteristic life (eta) with the formula given below in Figure 7-1. More information can be found in AMS 01-09.

[8] AMS 01-09 AusNet Services' Asset Risk Assessment Overview (October 2025)

**Figure 7-1: Weibull failure rate formula for new assets**

$$t_1 = 0.0 * \eta \text{ and } t_2 = 0.2 * \eta$$

$$\lambda = \frac{\left(\frac{t_2}{\eta}\right)^{\beta} - \left(\frac{t_1}{\eta}\right)^{\beta}}{t_2 - t_1} = \frac{(0.2)^{\beta}}{0.2\eta}$$

The eta and beta values for primary assets are as shown in Table 7-2.

**Table 7-2: Primary Asset Weibull Parameters**

| Asset Class | η (eta) | Β (beta) | Failure Rate |
|---|---|---|---|
| Power Transformers | 50 | 3.5 | 0.000358 |
| Circuit Breakers | 45 | 3.5 | 0.000398 |
| Current Transformers | 45 | 4.5 | 0.000080 |
| Voltage Transformers | 45 | 4.5 | 0.000080 |

## 7.2.4. Consequence of Failure

The consequence of plant failures, including loss of network service is established for each major asset and combined with the probability of such events to evaluate the risk costs for individual assets. Asset condition and asset criticality are considered in the asset renewal decision, where asset criticality is based on the consequence of an asset failure. The key risks considered in establishing the consequence of an asset failure (asset criticality) are described in Section 10.3 and includes market impact (involuntary load shedding and generation constraints), health and safety impact, financial impact, environmental impact and plant collateral damage.

## 7.2.5. Life Cycle Costs

### 7.2.5.1. Operational and Maintenance costs

Increasing operational and maintenance costs are considered in the economic cost-benefit analysis and asset renewal decision. Contributors to increasing operational and maintenance costs may include increasing maintenance activities and network losses.

### 7.2.5.2. Greenhouse Gas Emissions

$SF_6$ (sulfur hexafluoride) is a synthetic, odourless gas used extensively in the AusNet Transmission network as an insulating medium and as a high performing arc extinguishing medium for circuit breakers. The gas is broadly acknowledged as the highest performing medium and is globally in common use across energy networks. Despite its efficiency and effectiveness, $SF_6$ gas is a highly potent greenhouse gas, with a global warming potential of 23,500 t $CO_2$-e per tonne of $SF_6$[9]. $SF_6$ containing equipment is designed to avoid emitting the gas into the atmosphere, however, leaks can inadvertently occur throughout the asset lifecycle - from manufacturing through to disposal. In some cases, significant leaks may arise from aging equipment.

AusNet Services' approach to calculating the costs associated with emissions from $SF_6$ gas leaks in existing and new Transmission network assets is described below.

#### 7.2.5.2.1. Emissions from Existing Assets

To maintain the required dielectric properties for the operation of $SF_6$ containing equipment, the gas must be kept above minimum functional pressure. If pressure decreases due to leakage, operators must top-up the gas levels to

[9] Australian Government Clean Energy Regulator, "Estimating Emissions and Energy from Electricity Production and Consumption Guideline", August 2025

restore the required pressure. Details of $SF_6$ gas refills including date of refill, amount of $SF_6$ used and the equipment refilled - are used to estimate and value expected greenhouse gas emissions using the following approach:

(1) Extract available refill measurement data for assets from SAP

(2) Determine historic $SF_6$ leakage rates (kg per period) using one of the below methods. The period may be over a calendar year, or another interval aligned with top-up frequency.

  a. The total $SF_6$ (kg) refilled in each period

  b. The total number of refill measurements in each period multiplied by the estimated $SF_6$ loss per event for the selected assets (i.e. total $SF_6$ refilled / total number of refill measurements)

(3) Extrapolate leakage rates over the assessment period to determine the total $SF_6$ (kg) in each forecast period

(4) Convert total $SF_6$ (kg) in each forecast period to $CO_2$-e using a global warming potential of 23,500t $CO_2$-e per tonne of $SF_6$[9]

(5) Determine the value of greenhouse gas emissions in each period as per the AER's "Valuing Emissions Reduction" guidance and explanatory statement[10]

#### 7.2.5.2.2. Emissions from New equipment

Manufacturers advise a leakage rate of up to 0.05% of total $SF_6$ volume per year for new assets, while international standards limit the maximum leakage rate at the end of equipment design life to 0.1% of total volume per year[11]. Based on this data, the approach below is used to estimate and value the expected greenhouse gas emissions from new or refurbished equipment:

(1) Determine the annual leakage rate for the assets under consideration for renewal according to asset age:

  a. Age 0-15 years – flat leakage rate of 0.05% volume per year

  b. Age 15 years onwards – linear progression of leaks from 0.05% volume at age 15 to 0.5% volume by age 30

(2) Convert total $SF_6$ (kg) in each forecast period to $CO_2$-e using a global warming potential of 23,500t $CO_2$-e per tonne of $SF_6$[9]

(3) Determine the value of greenhouse gas emissions in each period as per the AER's "Valuing Emissions Reduction" guidance and explanatory statement[12]

### 7.2.6. Future Customer Requirements

Asset renewal plans are integrated with the shared network augmentation plans developed by AEMO and VicGrid, as well as connection network augmentation plans developed by distribution network service providers, to optimise economic benefits. The integration of these plans may lead to the advancement or deferral of asset renewal plans, or introduce new options for consideration in the planning process.

### 7.2.7. Spares and Technical Support

A contingency strategy is developed when a manufacturer no longer offers technical support and spare parts for key assets. Depending on the level of internal technical support and spare availability within AusNet Services, as well as the asset's criticality to the network, the strategy may involve replacing one asset to generate spares for maintaining other assets in less critical areas of the network. This strategy generally results in an improvement in asset restoration time during a failure, but does not enhance overall network reliability and availability.

# 8. Asset Renewal Planning Process

The main planning activities are discussed in this section of the report and consist of the following steps:

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[10] Australian Energy Regulator, "Valuing Emissions Reduction", May 2024

[11] IEC 62271-203:2022, High-voltage switchgear and controlgear – Part 203: AC gas-insulated metal-enclosed switchgear for rated voltages above 52 kV

[12] Australian Energy Regulator, "Valuing Emissions Reduction", May 2024

(1) Assess asset health and performance indices to develop asset failure rate curves, establish assets remaining service potential and calibrate to history.

(2) Quantify baseline risk based on the probability and consequence of asset failure, and verify whether the baseline risk has reached a level where a "Do nothing" asset management approach would compromise efficient service provision. The main hazards or effects that should be included are safety, reliability and security of supply (market impact), environmental impact, financial impact and collateral plant damage.

(3) Develop asset management options based on risk ranking, plant strategies, transmission line strategies and system strategies. Consider non-network options, including demand side options, as well as efficient integration of replacement and augmentation plans. Consider brownfield or greenfield type replacement, staged replacement, and refurbishment (opex) versus replacement (capex) trade-offs. Consider the future need for the assets and the economic feasibility of all proactive asset renewal options, given uncertainties in demand growth, new generation connections, generation retirements, etc.

(4) Develop scope of work and cost estimates for each credible option, considering the high-level feasibility of outage requirements and the staging of construction works.

(5) Assess the need to undertake a regulatory investment test (RIT-T) and make provision for the time required to undertake a RIT-T in the renewal planning process.

(6) Select asset renewal solutions, including deferred replacement when the baseline risk is small, and the asset can be managed without the need for refurbishment or replacement ("do nothing"). Deferred replacement is assumed to have a cost equivalent to the integrated replacement option. Run to failure should only be considered for assets that do not present significant safety or environmental hazards and can be rapidly and economically restored following failure.

(7) Consult with AEMO, VicGrid, and the respective distribution businesses regarding their long-term augmentation plans, and update the ultimate planning requirements for terminal stations and transmission lines. Integrate asset renewal and augmentation projects and plans.

(8) Select the most economical solution that complies with the asset management strategies and future augmentation planning requirements. Support compliance with technical limits, planning philosophies, regulatory criteria and guidelines, reliability and quality of supply standards, and asset management strategies.

(9) Use scenario planning techniques and sensitivity studies to establish the robustness of each option, including testing each option for asset stranding risk. Apply regret analysis to assess options selected based on criteria that minimise upfront cost, but may undervalue longer term planning outcomes, i.e. the horizon year plan.

(10) Undertake sensitivity studies to determine the economical project timing, considering changes in demand forecast, discount rate, cost of capital and asset failure rates.

(11) Prepare an asset renewal planning report documenting all considerations and recommendations.

(12) Prioritise transmission asset renewal projects based on the assessed failure risk, the company's business strategy and regulatory funding decisions.

(13) Integrate network plans and projects to support efficient project and program delivery.

(14) Document the plan and include it in the Annual Planning Reports. Initiate projects with RIT-Ts where thresholds require a RIT-T.

Figure 8-1 below provides a summary of the asset renewal planning process.

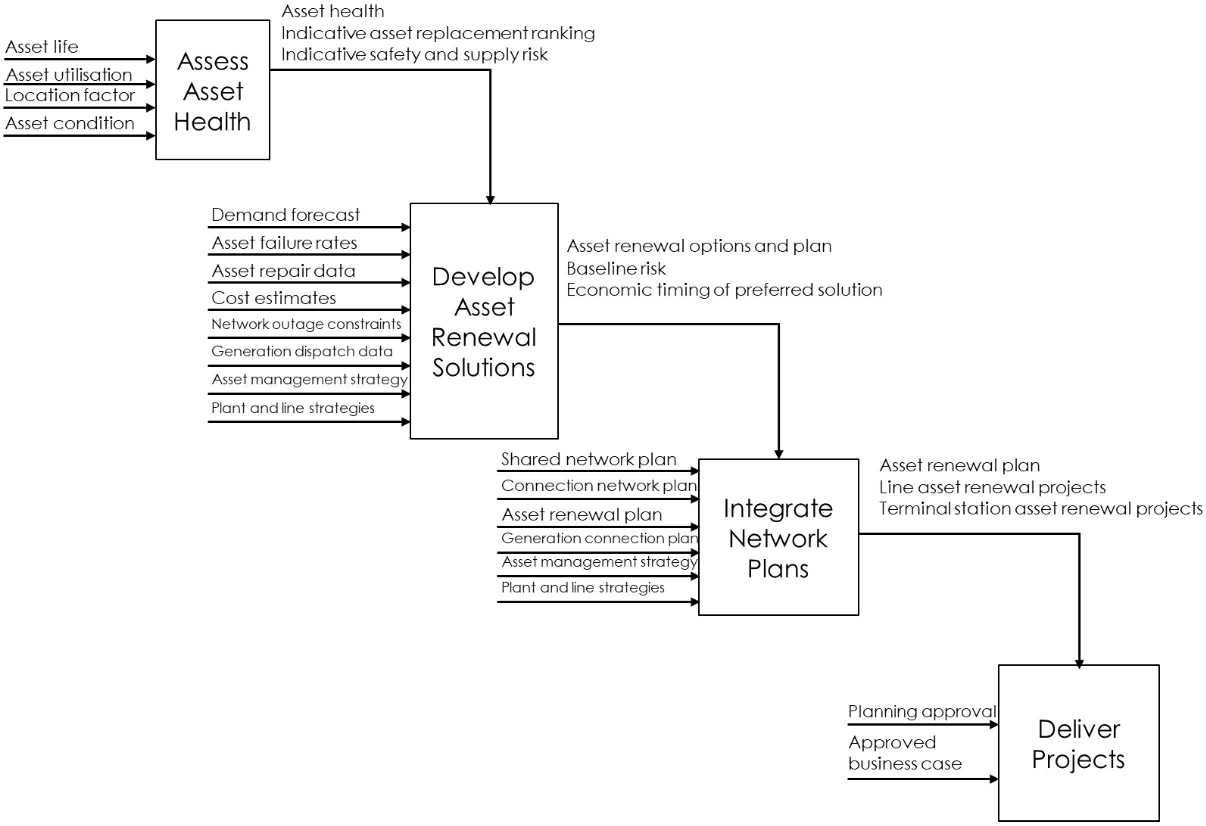



**Figure 8-1: Asset Renewal Planning Process**

# 9. Asset Renewal Options

# 9.1. Asset Refurbishment and Replacement

The asset renewal objectives described in Section 7.1 are met by either asset refurbishment or replacement, or a combination of refurbishment and replacement.

## 9.1.1. Asset Refurbishment

This asset management strategy involves refurbishing plant to extend its reliable service life. This is sometimes the most economic option and allows deferral of the more expensive asset replacement alternative, particularly when the future need for the asset is uncertain. However, in many cases, it is reliant on spare equipment being available while deteriorated plant is being refurbished. The economics of this option are predicated on the probability that known technical issues can be addressed.

In general, refurbishment addresses specific, known problems that would, if no remedial action were taken, lead to failure and shorten the service life of the asset. Generally, refurbishment improves the declining reliability of the plant but does not extend its useful service life. In most cases, refurbishment has only a minor impact on maintenance costs because refurbishment tends to stabilise rising future costs rather than dramatically reducing costs below historic levels.

This strategy requires careful analysis as benefits are unique to each refurbishment and are highly dependent on stabilizing or reducing a rising failure rate, with a secondary benefit of a small extension in reliable service life.

## 9.1.2. Asset Replacement

This asset management strategy involves replacing plant to support continued reliable service. While this strategy often has the highest up-front costs, it also tends to lead to the largest reductions in failure risk and maintenance costs. Replacement also presents an opportunity to modernise the plant which can avoid costs associated with obsolete equipment and may inherently improve the level of service.

Replacement is often the preferred option when the reliability of an asset is critical, when asset outages and spares are not available for refurbishment, or when refurbishment is simply an ineffective means for addressing poor reliability.

Plans for asset replacement look for efficiencies over the entire planning period, for example, by integrating the augmentation needs of VicGrid and those of distribution network service providers with AusNet Services' replacement plans. This approach optimises engineering and construction resources and minimises project risks and network outages for construction purposes.

The following options are considered in the asset renewal evaluation:

(1) **Replace-upon-Failure** is only employed in circumstances where the impact of asset failure on network performance, health, safety and the environment is insignificant or non-existent, and where the asset has a short procurement and replacement lead-time.

(2) **Renewal on Risk** optimises the asset's lifecycle cost with due consideration for health, safety and environmental factors, as well as community cost based on asset performance. This strategy requires sufficient asset condition and performance monitoring to predict deterioration of the respective plant with sufficient lead-time to enable renewal prior to failure.

(3) **Renewal by Asset Class** is employed when a class of asset has either a higher-than-acceptable failure rate or exhibits a greater degree of deterioration than other asset types. This approach avoids widespread deterioration in network performance due to multiple asset class-related failures.

(4) **Renewal on a Bay-by-bay (or Scheme/Network)** basis is employed when it is economic to replace all primary plant and equipment within a specific station switch bay or scheme. This strategy is often adopted for terminal station renewals where outage restrictions apply.

(5) **Replacement of Whole Station in Existing Location (Brownfield redevelopment)** is employed when it is economic to replace all assets in a single, coordinated project within the existing station or location. This is normally when station assets are approaching the end of their life and there are advantages in station reconfiguration.

(6) **Replacement of Whole Station in New Location (Greenfield redevelopment**) means constructing a replacement station on a new site. This is a more expensive strategy than undertaking works within an existing station as it requires procuring new land, establishing key infrastructure, and relocating associated transmission and distribution lines. It is usually only economic when the existing infrastructure is inadequate or in poor condition, or when replacement works cannot occur without sustained supply disruption due to limitations at the existing site.

## 9.2. Asset Renewal Programs and Projects

AusNet is focused on delivering optimal transmission network performance at efficient cost. To achieve the most efficient allocation of capital expenditure, asset renewal is either done at a project or program level depending on which approach would result in the most economic outcome.

### 9.2.1. Asset Renewal Programs

As described above, asset renewal can be conducted for a group of assets (e.g. a class of asset) installed throughout the Transmission network. This form of asset renewal is classified as an 'asset renewal program'.

### 9.2.2. Asset Renewal Projects

Renewal of assets of varying classes is often required at a single station or location. This is expected of stations at which assets were established at a similar period and thus exhibit similar levels of deterioration. Replacement of all assets at the station or location in a single coordinated project is often the most economic approach. This form of asset renewal is classified as an 'asset renewal project' and allows efficient allocation of expenditure by reducing internal labour, design and delivery costs by combining efforts into a single integrated project.

# 10. Economic Planning Criteria

AusNet Services undertakes economic appraisals of all asset renewal options and asset renewal investment decisions and the economic planning criteria are described in this section.

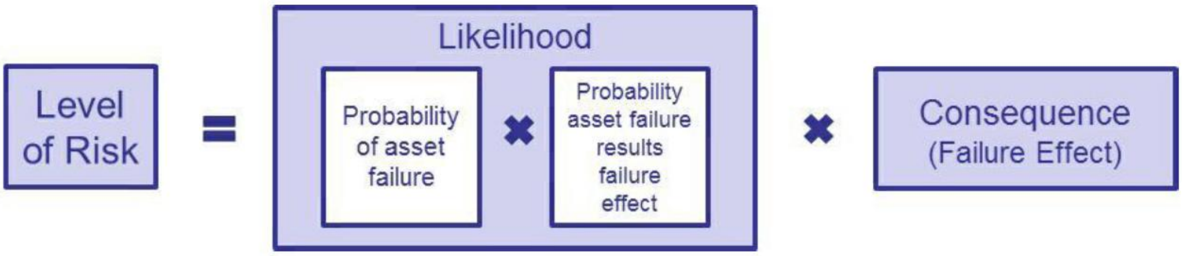
AusNet Services applies probabilistic planning methods to determine the economic viability of asset renewal. The baseline risk is first calculated to quantify the following hazards/risks:

- Health and safety risk presented by assets that could fail explosively or present a fire risk due to their design (e.g. porcelain bushings, oil used as an insulating medium, etc.)
- Market impact risk to consumers or the electricity market when asset failure could result in supply interruptions or network constraints and non-optimal generation dispatch.
- Financial Risk Cost. Upon failure of an asset, it is assumed that the asset is replaced and the financial consequence arising from the failure of the asset is calculated as per the Australian Energy Regulator (AER) Industry practice application note – Asset replacement planning, Section 5.1.2[13].
- Environmental risk, for example due to oil spillage
- Collateral plant damage risk for plant that could fail explosively, resulting in damage to adjacent plant and consequent costs for litigation, media liaison, emergency operational action and site clean-up

13 Australian Energy Regulator, "Industry practice application note for asset replacement planning," available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/industry-practice-application-note-for-asset-replacement-planning.

The monetised baseline risk is compared with the annualised cost of the asset renewal options to establish whether proactive asset renewal strategies are required to manage the asset failure risk, instead of continuing with reactive asset management strategies such as "Business as usual" or "Do nothing" approaches[14]. **Error! Reference source not found.** illustrates the methodology used to calculate the baseline risk, which is the probability weighted risk cost presented by asset failure.

**Figure 10-1: Baseline Risk Calculation**




# 10.1. Identifying the Assets at Risk

The need for asset renewal is identified by quantifying the asset failure risk (where expected cost is a function of consequence and probability) and by undertaking an economic evaluation of credible asset renewal options. The objective of the economic evaluation is to identify the option with the highest net present benefit or lowest expected present value (PV) cost, and the timing by when the asset renewal would be economical.

# 10.2. Asset Unavailability

Asset unavailability is calculated from the asset failure rate and Mean Time to Recovery information for the particular asset. Methodologies to calculate the asset probability of failure are detailed in AMS 01-09.

The following definitions are used to define asset unavailability:

- Failure Rate (λ(t)) is defined as the anticipated number of times an item will fail in a specified time period, t.
- Mean Time to Recovery (MTTR) is defined as the total amount of time spent performing corrective repairs, replacement or any other recovery option. It is the expected span of time from a failure (shut down) to the recovery completion.
- Unavailability (Pr(f)) is the probability that the component is in the failed state.

$$\mathbf{Pr}(\boldsymbol{f}) = \frac{\boldsymbol{MTTR}}{\boldsymbol{MTTR} + \frac{\mathbf{1}}{\boldsymbol{\lambda}}}$$

- A simplified version of the above formula, when the MTTR is small in comparison with the mean time to failure (MTTF), is as follows:

$$\mathbf{Pr}(\boldsymbol{f}) = \boldsymbol{MTTR} * \boldsymbol{\lambda}$$

AusNet only assess asset failure risk for the major asset classes such as power transformers, circuit breakers and instrument transformers, for Integrated Major Station projects. A "Plant Failure Factor" (PFF) is thus applied in risk assessments when appropriate to account for other assets such as isolators, earth switched, protection systems, control systems, busbars, interplant connections, surge arrestors, etc. that can also fail and impact transmission network users. A factor of 1.3 is normally used unless circumstances dictate a different factor to account for the failures of other assets that are not analysed on their own.

**Example:**

14 This approach is only used to provide a high level indication of whether investment may be economical as it assumes that the investment will mitigate all the base line risks identified.

A major transformer outage in a particular network's fleet is expected to occur once per 100 transformer-years. Therefore, in a population of 100 terminal station transformers, you would expect one major failure of any one transformer per year. The major outage rate for transformers (λ) = 1%.

On average, 2.6 months is required to repair the transformer and return it to service, during which time, the transformer is not in service. Mean time to recovery (MTTR) = 2.6 months.

On average, each transformer would be expected to be unavailable due to major outages for 0.217% of the time, or 19 hours in a year. The calculation of the transformer unavailability is as follows:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.2162\%$$

or

$$\Pr(f) = MTTR * \lambda = \frac{2.6}{12} * 0.01 = 0.2167\%$$

# 10.3. Consequence of Asset Failure

The key risks to be considered in the calculation of the monetised baseline risk are the following:

- **Market Impact Risk:** Load at risk that would not be supplied in the event of an asset failure is evaluated based on the jurisdictional planner or the distribution businesses' terminal station demand forecast and the latest value of customer reliability (VCR). Network constraints (generation constraints) that result in non-optimal generation dispatch in the National Electricity Market (NEM) are assessed through market simulations.
- **Health and Safety Risk:** Hazards to the safety of any person in an event of asset explosive failure or failure that involves fire, e.g. Human injury and fatality.
- **Financial Risk Cost** is calculated based on the following: The cost to reactively replace the failed asset and the asset failure rates
- **Environmental Risk:** Threat of adverse effects on the environment, e.g. environmental impacts due to oil leaks.
- **Plant Collateral Damage Risk:** Potential collateral damage of adjacent plants due to an asset explosive failure.

## 10.3.1. Supply Security Risk (involuntary load shedding)

An asset failure could result in involuntary load shedding, and the economic impact of such an event is assessed by undertaking network load flow and/or market studies. The requirement for network and/or market studies depends on the topology of the network, i.e. more detailed studies are required to quantify the supply security risk for asset failures that are part of a meshed network. The maximum supportable demand is calculated for all plausible network operating states when the asset failure risk is assessed for complex network configurations such as meshed networks.

Network and/or market studies may not be required when the network topology is simple, such as for radial networks or connection stations.

### 10.3.1.1. Demand Forecasts

AusNet Services uses the distribution businesses' terminal station demand forecast and AEMO's 2024 VAPR connection point forecast for asset replacement planning. These two demand forecasts provide the maximum active power and reactive power demands forecasted to occur (or be exceeded) in summer and winter, based on a one-in-two year (50% probability of exceedance, POE) and one-in-ten year (10% POE) likelihood for each financial year within the ten-year planning period.

The terminal station demand forecasts are used to assess the amount of load at risk under asset outage conditions, for single and multiple contingencies.

The Victorian demand forecasts are operational demand forecasts[15] that exclude rooftop solar generation and reflects grid-supplied electricity. However, the economic impact of an asset failure must also consider the impact on load normally supplied by rooftop solar generation to support that the risk is not understated. The methodology for integrating load that is normally supplied by rooftop solar PV into the forecast is explained in Section 10.3.1.3.

### 10.3.1.2. Value of Customer Reliability

The value of customer reliability (VCR) is the value that customers place on avoiding electricity service interruptions. The VCR varies widely between customer types, between countries and across time. In probabilistic transmission asset renewal planning, a VCR is used to value the economic benefits of a proposed asset renewal that is expected to reduce the unserved energy, so that this economic benefit can be compared with the cost of the asset renewal.

AusNet Services uses the latest VCR rates derived by AER[16] and as weighted by the distribution businesses based on the load composition for each individual terminal station. Table 10-1 shows the 2024 VCR values for residential and business customers. The average VCR across Victoria for 2024 is $35,780/MWh ($35.78/kWh).

**Table 10-1: Residential and Business VCR Values (AER Values of Customer Reliability 2024)**

**Residential customers**

**Table 1 Residential VCR values by jurisdiction**

| Jurisdiction | 2024 VCR ($/kWh) | 2019 VCR ($/kWh) | 2019 VCR, real* ($/kWh) |
|---|---|---|---|
| New South Wales (NSW) | 38.53 | 25.85 | 31.16 |
| Victoria | 49.23 | 21.43 | 25.84 |
| Queensland (Qld) | 36.09 | 23.76 | 28.64 |
| South Australia (SA) | 48.52 | 30.31 | 36.53 |
| Tasmania (Tas) | 35.69 | 16.96 | 20.45 |
| Australian Capital Territory (ACT) | 50.70 | 21.38 | 25.77 |
| Northern Territory | 30.69 | 18.31 | 22.07 |
| NEM | 41.48 | 24.08 | 29.02 |

Note: The 2019 VCR, real ($2024), have been calculated consistent with our annual adjustment mechanism (nominal 2019 VCR multiplied by a ratio of CPI for September 2024 and CPI for September 2019).

**Business customers**

**Table 2 Business VCR values**

| Customer segment | 2024 VCR ($/kWh) | 2019 VCR ($/kWh) | 2019 VCR, real* ($/kWh) |
|---|---|---|---|
| Agriculture | 22.25 | 37.87 | 45.65 |
| Commercial | 34.39 | 44.52 | 53.66 |
| Industrial | 33.49 | 63.79 | 76.89 |

Note: The 2019 VCR, real ($2024), have been calculated consistent with our annual adjustment mechanism (nominal 2019 VCR multiplied by a ratio of CPI for September 2024 and CPI for September 2019).

### 10.3.1.3. Energy at Risk

Energy at risk (EAR) can be defined as the amount of energy that would not be supplied during a component failure or system constraint.

The capacity of a terminal station with one transformer out of service is referred to as its "N-1" rating. The capability of the station with all transformers in service is referred to as its "N" rating.

[15] AEMO Transmission Connection Point Forecasting Methodology
[16] Australian Energy Regulator, Values of Customer Reliability 2024 – Final Report

Figure 10-2 below shows the annual load duration curve for the specific system under evaluation and the EAR for a N-1 contingency.

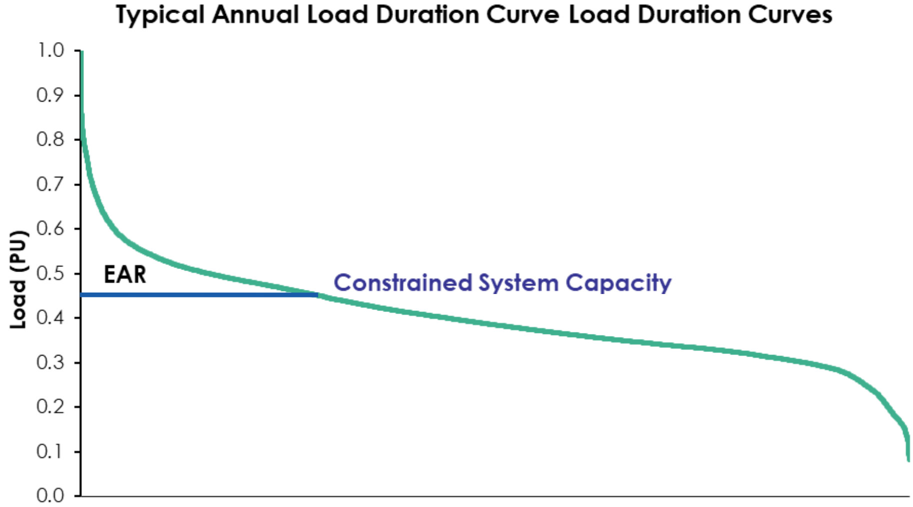



**Figure 10-2: Illustration of the calculation of the EAR**

AusNet assessed the average amount of energy supplied by rooftop solar generation for summer and winter in its distribution supply area during 2023 and used this information to include the economic impact of involuntary load shedding of customers that have rooftop solar generation.

On average, rooftop PV generation is contributing approximately 25% of the supplied energy in summer and 11% in winter. To add these amounts of energy back to the forecast and energy at risk calculations to account for the underlying demand a PV factor of 1.33 and 1.13 is used to scale the energy at risk up respectively based on the calculation below.

Average PV generation in summer = 25%

Average PV generation in winter = 11%

Summer rooftop PV factor = 1/(1-25%) = 1.33

Winter rooftop PV factor = 1/(1-11%) = 1.13

However, in certain cases, PV generation is accounted for by using a 5% contribution for winter and summer.

### 10.3.1.4. Expected Unserved Energy

The Expected Unserved Energy (EUE) is the product of the EAR and the probability of the network being in the constrained state.

The terminal station demand forecasts obtained from AEMO's *Victorian Connection Point Demand Forecasts* include both 50% probability exceedance (POE50) of the maximum demand and 10% probability exceedance (POE10) of the maximum demand. The following weightings are applied to determine the EUE:

10% POE weighting = 0.30

50% POE weighting = 0.70

$$\begin{aligned} EUE &= EAR \times PV_{factor} \times Pr\ (f) \\ &= [w_{10} \times EAR_{10} + w_{50} \times EAR_{D50}] \times PV_{factor} \times Pr\ (f) \\ &= [0.3 \times EAR_{D10} + 0.7 \times EAR_{D50}] \times PV_{factor} \times Pr\ (f) \end{aligned}$$

Where:

| | |
|---|---|
| Pr (f) | Probability of Failure |
| EAR | Energy at Risk |
| $PV_{factor}$ | Rooftop PV factor for summer/winter |

| | |
|---|---|
| $w_{10}$ | Weighting applied to 10%POE |
| $w_{50}$ | Weighting applied to 50%POE |
| $EAR_{D10}$ | Energy at Risk using 10%POE demand forecast |
| $EAR_{D50}$ | Energy at Risk using 50%POE demand forecast |

### 10.3.1.5. Monetised Supply Security Risk

The monetised supply security risk is equivalent to the expected cost to consumers of having their electricity supply interrupted for a certain period of time and is sometimes referred to as the community cost.

**Monetised Supply Security Risk = VCR x EUE**

In the economic analysis for a capital investment project (or program) that avoids or minimises the risk of supply interruptions, the community cost is treated as benefits. In other words, the benefit of an investment is the avoided community cost calculated as described above.

For asset renewal projects, the incremental benefit of an improvement in the asset failure risk usually equates to a reduction in the supply security risk and is calculated as the project supply benefits.

**Example:**

The following example illustrates the methodology to calculate "Expected Unserved Energy" for the summer season for a terminal station with two transformers with the annual load duration curve shown below. The methodology used to calculate the "Expected Unserved Energy for the winter season is calculated in the same manner.

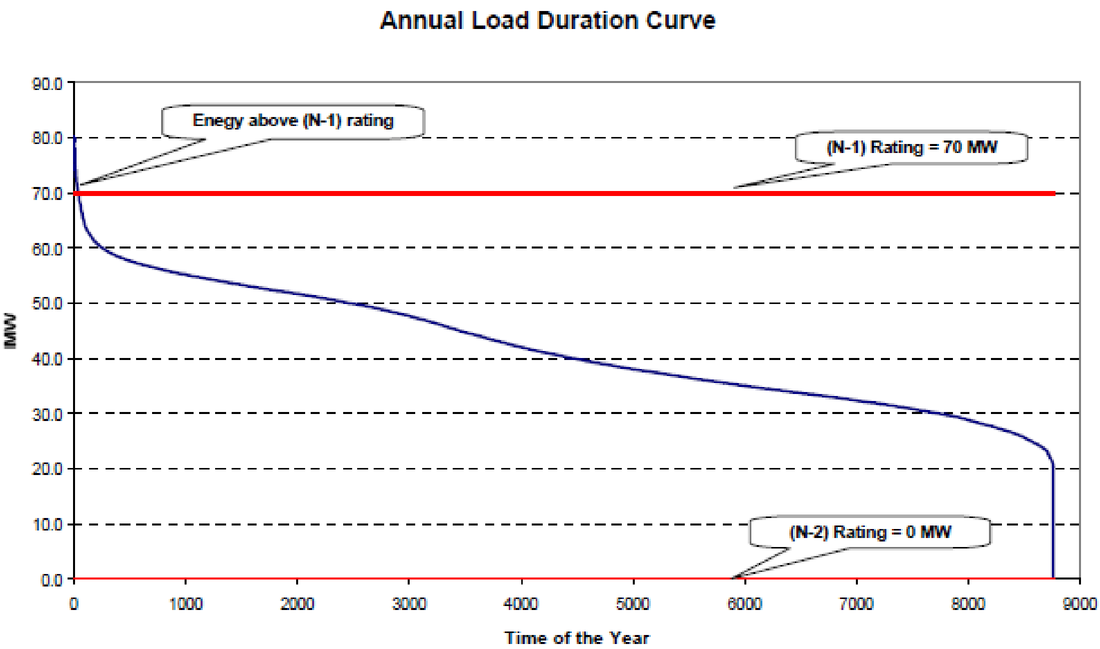



**Figure 10-3: Annual Load Duration Curve Example**

Where:

Energy above N-1 rating = 132 MWh

Energy above N-2 rating = 367, 877 MWh

Summer rooftop PV factor = 1.33

Unavailability Pr (f) of transformer A = 0.216%

Unavailability Pr (f) of transformer B = 0.216%

VCR = $30,000 per MWh

*Risk assessment calculation:*

First Order Contingency (N-1):

$EUE_{N-1}$ = $EAR_{N-1}$ x $PV_{factor}$ x [Pr (f) of transformer A or Pr (f) of transformer B]

= 132 MWh x 1.33 x [0.216% + 0.216%]

= 0.76 MWh

Second Order Contingency (N-2):

$EUE_{N-1}$ = $EAR_{N-2}$ x $PV_{factor}$ x [Pr (f) of transformer A and Pr (f) of transformer B]

= 367, 877 MWh x 1.33 x [0.216% x 0.216%]

= 2.28 MWh

Monetised Supply Security Risk = VCR x EUE

= $30,000 per MWh x [0.76MWh + 2.28 MWh]

= $91,000

### 10.3.2. Market Impact Cost (Generation constraint cost)

There are instances where a network outage at, for example, a switching station or generator connection point, would result in a generation constraint. Market dispatch modelling should be used to calculate the market impact cost (generation constraint cost) and the Supply Security Risk (involuntary load shedding) for these types of network constraints.

#### 10.3.2.1. Market Dispatch Modelling

Market dispatch modelling is used to assess the economic impact of generation constraints (and involuntary load shedding) when assets are unavailable for service due to an asset failure.

The incremental benefit of asset replacement investments is calculated by firstly calculating the market cost for an unconstrained network (base case or counterfactual). This is then compared with a study with the identified asset removed from service. The avoided market impact cost is the difference between these two studies and is used to justify asset replacement investment.

The classes of market benefits considered in an economic cost benefit analysis or RIT-T are defined in Paragraph 5 of the RIT-T Application Guide and include changes in generation fuel consumption, changes in voluntary and involuntary load curtailment, changes in network losses, changes in ancillary service costs, etc.

Several reasonable scenarios are considered to support a robust investment decision. These scenarios may be weighted in terms of their likelihood of occurrence and may include different future generation development scenarios; generator retirements; future transmission expansion plans (lines and transformers); different demand growth scenarios; changing fuel prices; technology efficiencies; and future demand management opportunities.

As guided by the RIT-T process:

In estimating the magnitude of market benefits, a market dispatch modelling methodology must be used and must incorporate:

- a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and
- a realistic treatment of the network constraints and losses,

The market modelling includes a period of ten years or more into the future and has to be of sufficient length to support all investment options are assessed on a level basis.

### 10.3.2.2. Market Impact Cost Example

The marginal market cost derived from the market modelling studies are multiplied by the asset's unavailability prior and post replacement to calculate the incremental project benefits and to ascertain whether the project benefits outweigh the project cost in the economic cost-benefits tests. (See section 10.2).

**Example:**

A market study is required to assess the market impact cost of a Hazelwood Terminal Station (HWTS) 500/220 kV transformer failure because generation rescheduling may be required following an unplanned outage of a HWTS 500/220 kV transformer. The most likely result would be a thermal constraint being invoked, resulting in generation being scheduled out of merit to support the remaining three 500/220 kV transformers are not overloaded.

*Assumptions:*

The Mean time to recovery (MTTR) is assumed to be 2.6 months in this example. (A 500/220 kV transformer would usually have a longer MTTR, but a spare phase for the three banks of 500/220 kV transformers is available on site at HWTS).

*Risk assessment calculation*

The transformer unavailability is:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.216\%$$

An example of the marginal market cost (MMC) provided by AEMO is shown in Table 10-2 Table 10-2.

**Table 10-2: Marginal market cost (MMC) associated with the HWTS A4 transformer**

| Year | 2013-14 | 2014-15 | 2015-16 | 2016-17 | 2017-18 | 2018-19 | 2019-20 | 2020-21 | 2021-22 |
|---|---|---|---|---|---|---|---|---|---|
| Marginal Market Cost ($,000) | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] |

Monetised Market Risk Cost (2013-14) = MMC (2013-14) x Pr(f)
= $1,220,000 x 0.216%
= $2,638

## 10.3.3. Safety, Plant Collateral Damage and Environmental Risks

The Electricity Safety Act requires AusNet Services to "*design, construct, operate, maintain and decommission its supply network to minimise, as far as practicable, the hazards and risks to the safety of any person arising from the supply network.*[17]

What is considered "practicable" is determined by having regard to:

- the severity of the hazard or risk in question; and
- state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and
- the availability and suitability of ways to remove or mitigate the hazard or risk; and
- the cost of removing or mitigating the hazard or risk.[18]

The Occupational Health and Safety Act requires AusNet Services to:

> *"so far as is reasonably practicable, provide and maintain for employees of the employer a working environment that is safe and without risks to health".*[19]

When determining what is (or what was, at a particular time), reasonably practicable in ensuring health and safety, the OHSA requires that regard be had to the following matters:

[17] Electricity Safety Act 1998 (Vic), section 98(a).
[18] Electricity Safety Act 1998 (Vic), section 3.
[19] Occupational Health and Safety Act 2004 (Vic), Section 21(1).

- the likelihood of the hazard or risk concerned eventuating;
- the degree of harm that would result if the hazard or risk eventuated;
- what the person concerned knows, or ought reasonably to know, about the hazard or risk and any ways of eliminating or reducing the hazard or risk;
- the availability and suitability of ways to eliminate or reduce the hazard or risk;
- the cost of eliminating or reducing the hazard or risk.[20]

In practice this means safety risk should be proactively managed until the cost becomes grossly disproportionate to the benefits[21].

The failure effect cost for safety is the product of:

- Likelihood of consequence
- Value of statistical life
- Value of Lost Time Injury
- Disproportionality factor

The likelihood of consequence is sourced from the DNO Common Network Asset Indices Methodology (Table 215). The value of statistical life is sourced from the Australia Government Best Practice Regulation Guidance Note Value of statistical life, escalated to current year dollars.

The value of a lost time injury is source from Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13) (November 2015), Table 2.3b Electricity, Gas, Water and Waste Services.

The disproportionality factors provide guidance on the reasonableness of costs associated with safety risk mitigation measures to meet the requirements of the Electricity Safety Act 1998. They are a measure of society's expectation of how much should be spent to prevent a fatality. Higher values of disproportionality are justified when the consequences or likelihood are higher. They may also be higher when there is a low level of trust that a risk is being adequately managed.

**Table 10-3** gives safety effect costs in 2014 dollars[22] using the following inputs:

- The reference safety probabilities given in the DNO Common Network Asset Indices Methodology
- The value of statistical life of $5.7m in 2024 dollars, as per the Value of Statistical Life guidance note[23]
- The value of lost time accident of $162,780 per event for Electricity, Gas, Water and Waste Services, as per Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13), Table 2.3b
- A disproportionality factor of 3 for a single fatality of either a member of the public or a worker

| Asset Type | Lost Time Accident[24] | Death or Serious Injury to Public[25] | Death or Serious Injury to Staff[26] | Safety Effects Cost (in 2014 dollars) |
|---|---|---|---|---|
| Circuit Breaker (≥132 kV) | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] |
| Transformer (≥132 kV) | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] | [ C.I.C ] |

**Table 10-3: Safety Effects Cost**

The following assumptions are used to monetise plant collateral damage and environmental hazards presented by plant in AusNet Services' cost-benefit studies to establish the scope and timing of remedial projects:

- Plant that contains large volumes of oil poses an environmental risk with an average consequence cost of $30K

[20] Occupational Health and Safety Act 2004 (Vic), Section 20(2).
[21] Practical application of SFAIP in project specification 2012
[22] The safety effect cost is then escalated with CPI to present the cost in the year of the assessment
[23] Value of Statistical Life Guidance Note, The Office of Impact Analysis, 26 November 2024
[24] From Table 215 of *DNO Common Network Indices Methodology*, Health and Criticality Version 1.1, 30 January 2017
[25] From Table 215 of DNO Common Network Indices Methodology, Health and Criticality Version 1.1, 30 January 2017
[26] From Table 215 of DNO Common Network Indices Methodology, Health and Criticality Version 1.1, 30 January 2017

- Transformer with oil that contains poly-chlorinated biphenyls (PCB) poses an environmental risk with an average consequence cost of $100k per event
- Plant collateral damage, including consequent supply outages, is on average [ C.I.C ]

The method of calculations and the assumptions applied in monetising the risks above are further discussed in the example below.

## 10.3.4. Network Performance Incentive Schemes

The transmission network has a performance incentive scheme the Service Target Performance Incentive Scheme (STPIS).

The STPIS[27] has been developed by the Australian Energy Regulator (AER) in accordance with clause 6A.7.4 of the National Electricity Rules (NER). This scheme presently consists of the following three components:

- Service Component – provides an incentive to reduce the occurrence of unplanned outages and to return the network to service promptly after unplanned outages that lead to a supply interruption.
- Market Impact Component – provides an incentive to reduce the impact of planned and unplanned outages on wholesale market outcomes. This component has been suspended in latest STPIS guidelines (Version 6, 17 Aprile 2025) and will not be applicable in the next TRR.
- Network Capability Component – provides an incentive to deliver benefits through increased network capability, availability or reliability through minor capex or opex projects.

Outages on assets that are not providing prescribed transmission services are excluded from these two incentive schemes, but may have contracted performance standards.

### 10.3.4.1. STPIS – Service Component

The Service Component of the STPIS consists of four parameters, which measure different aspects of service performance. These parameters measure network reliability by focusing on unplanned outages (ability to minimise the number of events and to quickly rectify them when they occur) and by providing an incentive for TNSPs to improve their performance. The parameters are:

- Average Circuit Outage Rate – measures the frequency of unplanned (forced and fault) outages on lines, transformers and reactive plant
- Loss of Supply Event Frequency – measures the frequency of outages which cause a loss of supply to customers
- Average Outage Duration – measures the duration of unplanned outages with a loss of supply
- Proper Operation of Equipment – requires TNSPs to report on near miss events such as failures of protection systems, material failure of the Supervisory Control and Data Acquisition (SCADA) system and incorrect operational isolation of primary and secondary equipment. No financial incentive is associated with this parameter.

The weightings applied to each parameter and sub-parameter of the Service Component are specified in Table 10-4Table 10-4, where MAR is the maximum allowed revenue for the relevant calendar year[28].

27 Australian Energy Regulator, Final: Electricity transmission network service providers: Service target performance incentive scheme, Version 04, 20 December 2012, AER reference 45236-D12/137417.

28 AusNet Services' regulatory year runs from 1 April to 31 March in the following year. To account for this, there is a three-month lag between when AusNet Services' performance is measured, and when the financial incentive adjustment is made to AusNet Services' MAR.

**Table 10-4: Weightings for each parameter/sub-parameter**

| Parameter | Weighting (MAR %) |
|---|---|
| **Unplanned outage circuit event rate:** | **0.75** |
| Lines event rate – fault | 0.20 |
| Transformer event rate – fault | 0.20 |
| Reactive plant event rate – fault | 0.10 |
| Lines event rate – forced | 0.10 |
| Transformer event rate – forced | 0.10 |
| Reactive plant event rate – forced | 0.05 |
| **Loss of supply event frequency:** | **0.30** |
| > (x) system minutes | 0.15 |
| > (y) system minutes | 0.15 |
| **Average outage duration** | **0.20** |
| **Proper operation of equipment** | **0.00** |

*(Source: Australian Energy Regulator, Final: Electricity transmission network service providers: Service target performance incentive scheme, Version 06, 17 April 2025*

Table **10-5**Table **10-5** shows the caps, floors and targets which are defined as:

- **Cap** – the level of performance that results in a TNSP receiving the maximum financial reward attributed to a parameter.
- **Floor** – the level of performance that results in a TNSP receiving the maximum financial penalty attributed to a parameter.
- **Target** – the historical average performance attributed to a parameter for which a TNSP would not receive a reward or penalty.

**Table 10-5: Values for service component caps, floors and targets for 2022–27**

| Parameter | Distribution | Cap (5th percentile) | Target | Floor (95th percentile) |
|---|---|---|---|---|
| **Average circuit outage rate** | | | | |
| Line event rate – fault | Gamma | 12.43% | 17.09% | 22.37% |
| Transformer event rate - fault | Erlang | 6.49% | 11.97% | 18.80% |
| Reactive plant event rate - fault | Dagum | 14.90% | 20.67% | 30.43% |
| Line event rate – forced | FatigueLife | 3.82% | 10.14% | 20.74$ |
| Transformer event rate - forced | Burr12 | 7.54% | 11.97% | 15.88% |
| Reactive plant event rate - forced | Burr12 | 19.65% | 27.78% | 34.66% |
| Loss of Supply Event Frequency | | | | |
| Number of events greater than 0.05 system minutes per annum | Poisson | 0 | 1 | 4 |
| Number of events greater than 0.30 system minutes per annum | Poisson | 0 | 1 | 2 |
| | | | | |
| Average Outage Duration | Triang | 10.2 | 45.6 | 87.2 |
| Proper operation of equipment (number of events): | | | | |
| Failure of protection system | Poisson | 22 | 31 | 40 |
| Material failure of SCADA | Geometric | 0 | 1 | 3 |
| Incorrect operational isolation of primary or secondary equipment | Poisson | 3 | 6 | 11 |

### 10.3.4.2. STPIS – Market Impact Component

In monitoring market outcomes following the introduction of service standard incentives, it was observed that planned outages scheduled during peak periods (for example, in summer) could constrain off generators, forcing AEMO to dispatch more expensive alternatives. The market impact was often substantial, and increases in spot market prices could flow through to contract prices and ultimately retail prices paid by households and businesses.

In response, metrics of the market impact of transmission congestion were analysed, leading to the development of the MIC. However, the increasing volumes of renewables connecting at diverse and decentralised locations, combined with increasing exposure to weather-driven supply availability risks and an already constrained network, has contributed to a significant increase in the number of MIC events over the past five years. TNSPs now often face maximum penalties regardless of their actions.

Through industry consultation conducted over the last two years, the AER has suspended this STPIS component on the basis that the mechanism, as designed, is no longer fit for purpose, as part of the latest AER's STPIS Guidelines (Version 6) released in April 2025.

This suspension will be effective from the start of AusNet's next TRR period, 1 April 2027. The AER will initiate a technical working group this year to develop alternatives to the MIC.

### 10.3.4.3. STPIS – Network Capability Component

The Network Capability Component has been introduced to encourage projects that offer incremental or small improvements to the capability of existing transmission network, particularly those parts that are most important to determining spot prices and at times when network users place greatest value on the reliability of the transmission system.

From 1 April 2027, under the latest AER STPIS Guidelines, AusNet will identify these projects annually, rather than for the whole revenue period under the previous guidelines. AusNet will work with VicGrid, the new Victorian Planner from 1 Nov 2025, to publish the proposed projects, as required by Guidelines, within the Victorian Annual Planning report (VAPR).

# 10.4. Option and Project Selection Methodology

By aggregating all the asset failure risk costs, the baseline risk for the terminal station is valued. The baseline risk increases over time due to both the deterioration in condition of the assets and demand growth. It presents the risk cost for the "Business as Usual" (counter factual) option, which is used to define the avoided cost or benefits of the investment options .

The process chart in Figure 10-4 below shows how individual asset replacement projects are being assessed by quantifying the asset failure risk (where expected cost is a function of consequence and probability) and by undertaking an economic evaluation of credible options. The objective of the economic evaluation is to identify the option with the lowest present value (PV) cost.

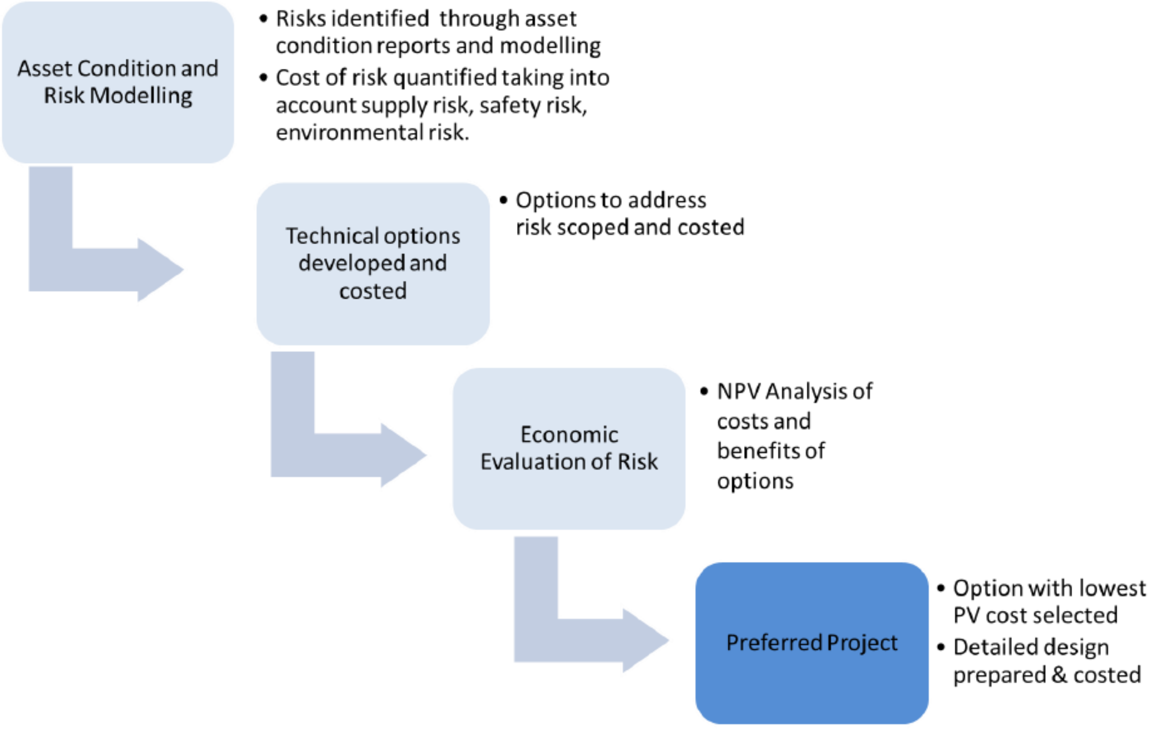



**Figure 10-4: Project Selection Method**

Different technically credible and feasible options to address the identified risk, ranging from refurbishment to asset replacement, are identified and scoped in the option and project selection stage of the asset renewal planning process.

Analysis is also undertaken across projects to identify potential efficiencies of coordination of project scope and timing. For example, some minor replacement work may be included in a major replacement or augmentation project to attain synergies in project design, project management and project establishment costs. This reduces the cost of minor replacement work and supports that new assets are configured to function reliably with other assets, as an integrated system. The shared network augmentation needs of AEMO and the connection asset augmentation needs of the distribution businesses are considered in the scoping and scheduling of all asset replacement work.

Initial project cost estimates are used in the economic evaluation to ascertain which option maximises the net present benefits. The Net Present Value (NPV) study analyses the costs and benefits of each option, with the aim of identifying the most economical option (the preferred option) for a range of planning scenarios and input assumption sensitivities.

# 10.5. Scenario Planning and Sensitivity Studies

Scenario planning and sensitivity studies around demand growth, discount rate, VCR rate and asset failure rate are conducted for new investments to test the robustness of the economic evaluation and option selection. This is a crucial step in ensuring replacement investment is economic under a range of reasonable scenarios[29].

Figure 10-5 shows how the following two credible options have been evaluated to ascertain which option delivers the highest net present value (NPV) benefits for a range of planning scenarios and input assumptions (demand growth, discount rate, VCR rate and asset failure rate):

- Option 4 – In Situ Replacement
- Option 6 – Replace in new location

The most economical option is the option that maximises the NPV benefits for most of the planning scenarios or input assumptions. In this example it is Option 4 - In situ replacement by a small margin.

[ C.I.C ]

**Figure 10-5: Economic option selection methodology**

Option 4: In Situ Replacement is considered a robust solution[30] as it delivers NPV benefits for all twelve scenarios, i.e. the expected outcome has been tested taking into account its variability and the NPV benefits ranges from $10.7 M

[29] The Transmission Planning Assumptions are detailed in Appendix A
[30] A robust solution is a solution for which the objective value for any realised scenario remains within the expected objective value for all possible scenarios.

to $30.6 M compared with the "Business as Usual" (counter factual) option. It also delivers the highest NPV benefits of the two options (Option 4 and 6) for all scenarios except the "High demand growth" scenario.

Scenario analysis, with the scenarios used by AEMO in their most recent Integrated System Plan (ISP), is also used to support the investment option that maximises the net present benefit for the chosen scenarios is selected as the preferred option. The following three scenarios are used Slow Change (weighting of 25%), Central Scenario (50% weighting) and Fast Change (25% weighting). This is consistent with the RIT-T requirements and practice notes on risk-cost assessment methodology.[31]

**Table 10-6: Scenario Analysis**

| Parameter | Slow Change Scenario | Central Scenario | Fast Change Scenario |
|---|---|---|---|
| Description | a slow-down of the energy transition, characterised by slower changes in technology costs, and low political, commercial, and consumer motivation | the pace of transition is determined by market forces under current federal and state government policies | a more rapid technology-led transition, its costs reduced by advancements in grid-scale technology and targeted policy support |
| Weighting | 25% | 50% | 25% |
| Demand forecast | AEMO 2024 VAPR Connection Point Forecasts - 15% | AEMO 2024 VAPR Connection Point Forecasts | AEMO 2024 VAPR Connection Point Forecasts + 15% |
| Value of customer reliability[32] | Latest AER VCR figures – 30% | Latest AER VCR figures | Latest AER VCR figures + 30% |
| Network option capital cost | AusNet Services assessment - 15% | AusNet Services assessment | AusNet Services assessment + 15% |
| Discount rate | 3% - the WACC rate of a network business | 7% - the latest commercial discount rate from IASR | 10% - a symmetrical adjustment upwards |

It is also important to consider irreversibility and uncertainty in investment decisions, where asset renewal investments are normally undertaken for asset with very long asset lives (45 years on average). Breakeven analysis provides an indication of how long (number of years) it will take before the present value benefits exceed the present value cost for the particular investment.

The proposed investment for the example shown in Figure 10-6 delivers NPV benefits after year 8. Due consideration of uncertainty in all planning assumptions must be considered in the planning decision; particularly for investments that have a breakeven point after more than ten years, has considerable uncertainty in planning assumptions such as future demand growth and where the economic investment decision is sensitive to changes in the assumptions.

[31] Australian Energy Regulator, *"Industry practice application note for asset replacement planning,"* available at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/industry-practice-application-note-for-asset-replacement-planning, viewed on 7 November 2019.

[32] The range of values used for the Value of Customer Reliability (VCR) is 'consistent with the confidence interval ranges applied to VCR estimates.' Australian Energy Regulator, *"Values of Customer Reliability, Final report on VCR values,"* page 84, available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf, viewed on 12 February 2020.

[ C.I.C ]

**Figure 10-6: Investment Breakeven Analysis**

A Regret function can be used to assess, which option minimises the maximum loss which could result from selecting a particular option. This methodology compares the NPV for each option across different scenarios with the NPV which could have been achieved if the outcome had been known in advance and the most appropriate option chosen. The investment decision can also be based on the expected net present value (ENPV) where probabilities can be ascribed to particular outcomes.

Selective asset replacement options often result in residual risk, which need to be quantified and tested to ascertain whether it is within the corporate accepted risk profile, particularly where residual safety risk results from selective or staged asset renewal options.

Investment decisions are characterised not only by irreversibility and uncertainty, but also by flexibility in the timing of the investment. The methodology to calculate the economic timing of a new investment is discussed in the next section.

# 10.6. Economic Project Timing

Efficient network investments proceed once the annual service quality improvement exceeds the annual cost of the investment. The economic timing of an asset replacement is thus determined based on a comparison of the annual cost and benefits provided by the replacement. Under this evaluation approach, the economic timing is identified as the point in time at which the annual incremental benefits exceed the annualised cost.

The economic benefits considered in the evaluation include savings achieved by lowering network losses and operating and maintenance cost, reduction in safety, plant collateral damage, financial and environmental risk costs, and reducing market impact risk (generation constraint cost and customer load at risk). The reduction in customer load at risk, expressed as the Energy at Risk (EAR), is valued at the VCR.

The annualised capital cost of the asset replacement is used in the economic cost-benefit evaluation, representing the cost of the asset replacement. The methodology used to assess the economic time for the preferred option to proceed is described next.

# 10.7. Annual Levelised Capital Cost

The incremental capital cost or annual levelised capital cost (ALCC) of the capital investment (P) is calculated by applying the capital recovery factor (CRF) and the present value factor (PVF) to the initial capital amount as illustrated in the figure and formulas below.

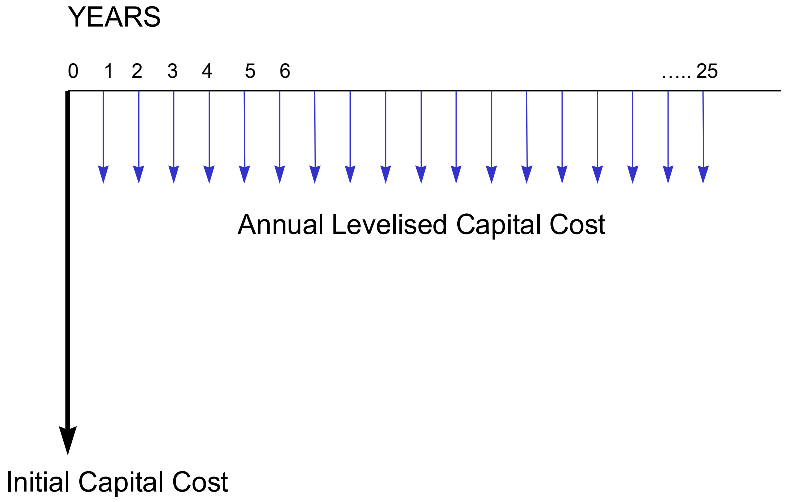



**Figure 10-7: Illustration of the calculation of the ALCC**

The annual levelised capital cost series starts in year 1. To obtain the annual levelised capital cost (annuity), which is equivalent to the investment made in year 0, the PVF is calculated with n = 1 (Equation 2) and multiplied with the CRF (Equation 1) to obtain Equation 3.

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$ Equation 1

$$PVF = \frac{1}{(1+i)^n}$$ Equation 2

$$ALCC_{Year0} = P\frac{i(1+i)^{(n-1)}}{(1+i)^n - 1}$$ Equation 3

The regulatory investment test specifies that present value calculations must use a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The weighted-average cost of capital for regulated electricity infrastructure ought to provide the lower bounds of the discount rate used in any sensitivity analysis.

# 10.8. Economic Cost-Benefit Evaluation

Once the economic costs and benefits of the replacement have been calculated a decision is made regarding the timing of the replacement. A replacement is justified economically in the year that the benefits exceed the cost of the replacement.

This test relies on the assumption that an adequate level of service quality and network reliability would be provided to network users, when using the VCR in the calculation of the incremental worth of service quality improvement, once it exceeds the incremental cost to provide that improvement.

# 10.9. Economic Investment Year Sensitivity Studies

Sensitivity studies around the discount rate, VCR rate, asset failure rate, project capital cost and demand growth scenarios are conducted to test the robustness of the proposed economical investment year of the selected option. Figure 10-8 shows how sensitive the project economical investment year is to changes in asset failure rate.

[ C.I.C ]

**Figure 10-8: Project Economical Timing Sensitivity Study**

# 10.10. Preferred Option

A detailed project scope and cost estimate is prepared for the most economic option. AusNet Services does this using a detailed technical scope of works and current unit costs for installing assets. This resulting cost estimate is the most likely cost of the project. The estimate does not capture possible changes in unit costs but does account for the expected cost of various project contingencies (estimated using Monte Carlo analysis).

AusNet Services also explores the potential for efficiencies to be derived by staging the delivery of large complex projects. Under this approach, AusNet Services identifies the highest asset failure risks so that these can be addressed in a timely fashion, while lower-risk project components may be deferred.

Overall, AusNet Services' approach is consistent with the annual Victorian transmission plans published by AEMO (Victorian Annual Planning Report), VicGrid's Victorian Transmission Plan and the distribution businesses' Transmission Connection Planning Report. It is also consistent with the principles underpinning the Regulatory Investment Test for Transmission (RIT-T).

# 11. Technical Planning Criteria and Planning Standards

AusNet Services' Stations Design Manual describes AusNet Services' standards, policies and processes required for the design of all stations including terminal stations, power station switchyards and transmission lines.

## 11.1. Ratings

Plant and network elements are designed for a maximum operating temperature and this limits their capability to a maximum load. Plant and equipment ratings depend on ambient temperature and both summer and winter ratings are defined, but it is the summer limitation that usually is the most critical.

All items of plant in a terminal station will have defined maximum current carrying capacities. Transformers, circuit breakers, droppers, inter plant connections, isolators etc. will all have maximum capabilities defined in various ways. The plant data sheets for each station will define most of these ratings and in many cases, it will simply be the continuous current rating.

Ratings for overhead lines are based on maximum operating temperatures and minimum clearances as specified in the Electricity Safety (Network Assets) Regulations 1999, ENA C(b)1 – 2006 "Guidelines for design and maintenance of overhead distribution and transmission lines" and the Overhead Line Design manuals.

Ratings for underground cables are based on maximum operating temperatures and are specified in the Underground Cable Design Manual.

Ratings for transformers are based on maximum operating temperature and the manufacturer's continuous rating. Cyclic ratings, which recognise varying load and ambient temperature cycles are calculated for cables and transformers.

Ratings for other equipment are defined by manufacturers' specifications.

### 11.1.1. Power Transformers

For more complex items of plant such as transformers a range of ratings are defined that may include the following:

- Continuous rating. This is the load that can be carried on a continuous basis as the name suggests. This will result in the transformer having a winding temperature of typically 130 degrees Celsius.
- Summer and winter cyclic ratings. This is the highest point of a cyclic load curve for the relevant season that the transformer can carry and is typically around 130% of the continuous rating. The transformer can carry this cyclic load for any number of consecutive days.
- The summer and winter limited cyclic rating allows a single day of higher loading than the cyclic rating. It is typically 5% to 10% higher than the cyclic rating.
- It allows for a higher transformer loading on this day and would be used to provide operators time to transfer load away from the station.
- The limited cyclic rating is only available where a station operates with more than one transformer in parallel, sharing the load between the transformers. An outage that results in increased loading through the remaining transformer/s will be preceded by lower loading on each transformer. It is important to note that the full limited cyclic rating is only available where a station has operated at or below the N – 1 rating.
- N – 1 station rating. The N – 1 rating refers to the rating of the station with one transformer out of service. The N – 1 rating is also often referred to as the "firm rating". In cases where a station has only a single transformer there is strictly speaking no firm rating, but usually the load transfer capability will be quoted. Shunt capacitor banks are included in the station rating calculation.

## 11.2. Fault Levels

Fault levels in the network must be maintained within the ratings of switchgear, plant and lines and within requirements of the Distribution Code, Station Design Manual and AEMO's Victorian Transmission System Overview – Technical Standard.

Most augmentations including new transformers and upgraded or new lines will result in an increase in fault levels and requirements to address this issue must be included in augmentation plans.

# 12. Asset Renewal Planning Report

A detailed planning report is required for each major asset renewal project. The report provides an analysis of all viable options and selects the best economic option to address the identified risks and to maintain the efficient delivery of electrical energy consistent with the National Electricity Rules (NER), stakeholder's requirements and AusNet Services' asset management strategies. The planning report covers the following areas:

- Asset condition – Provides a summary description of the condition of key primary and secondary equipment, asset condition rankings and references to condition assessment reports and/or asset management strategies (where applicable).
- Future Planning Requirements – Any significant asset replacement works must consider the long term shared network and connection network development plans of AEMO, VicGrid and the distribution businesses respectively to support individual decisions will not impede efficient future augmentation or compromise security of supply. Consultations with AEMO, VicGrid and distribution businesses in relation to their future plans are recorded.
- Emerging Constraints – Identify the risks presented by the deteriorated assets, which are typically security of supply risks, health and safety risks, environmental hazards, financial risks and plant collateral damage risk. Transmission planning assumptions (refer Appendix A) are used to quantify the risks, establish the baseline risk and define the residual risk after the implementation of the remedial actions.
- Technical Analysis of Options – Identify a range of possible solutions; describe the works involved, project advantages/limitations (if any) and the estimated cost for delivering each individual solution.
- Economic Analysis – The present value (PV) cost (considering the total project capital cost, operating and maintenance cost and expected risk costs) for all credible options is calculated. The discount rate used is a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector. The approach is outlined in the Energy Networks Australia RIT-T Economic Assessment Handbook[33], applying contemporary parameter values. Sensitivity testing on the discount rate is also undertaken. This allows for all the viable options to be ranked based on their economic merits. The option with the lowest PV cost is the most economic option. Sensitivity and scenario planning studies are conducted to assess project risk and uncertainty.
- Scenario Analysis - Scenario analysis is used to select the investment option that maximises the net present economic benefit across selected scenarios.
- Recommended Option and Timing – Specify the preferred option to address the emerging network constraints and its economical timing.
- Sensitivity Analysis – Sensitivity analysis is applied to test the robustness of the preferred solution. Typically, sensitivity testing is conducted on changes in input costs, forecast plant failure rates, demand growth scenarios, discount rates, project capital cost, and value of customer reliability.
- Scope of Work - Provide a summary of the high level scope of work for the preferred solution.

[33] Energy Networks Australia, RIT-T Economic Assessment Handbook, March 2019, page 46

# 13. Schedule of Revisions

| ISSUE | DATE | AUTHOR | DETAILS OF CHANGE | APPROVED |
|---|---|---|---|---|
| 1 | 12/02/2014 | [ C.I.C ] | Draft guideline for comment | [ C.I.C ] |
| 2 | 21/03/2014 | [ C.I.C ] | Final | [ C.I.C ] |
| 3 | July 2014 | [ C.I.C ] | Update | [ C.I.C ] |
| 4 | October 2015 | [ C.I.C ] | Update of guideline | [ C.I.C ] |
| 5 | March 2016 | [ C.I.C ] | Update of guideline to include consideration of asset stranding risk in option analysis | [ C.I.C ] |
| 6 | April 2020 | [ C.I.C ] | Revised safety risk, VCR, economic planning criteria and general update | [ C.I.C ] |
| 7 | October 2020 | [ C.I.C ] | General update | [ C.I.C ] |
| 8 | 30/10/2025 | [ C.I.C ] | General update | [ C.I.C ] |

# A. Regulated Investment Test for Transmission

## A.1. Introduction

On 18 July 2017, the AEMC made the National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017 No 5 (Repex Rule). The Repex Rule made a number of amendments to the existing planning and investment framework with the aim of creating a set of requirements that will apply to both replacement and augmentation investments.

In Victoria, from 1 November 2025, VicGrid is responsible for the augmentation of the transmission network. AusNet Services and other transmission asset owners are responsible for the replacement of transmission assets they own. The RIT-T for transmission network augmentation has been in effect for many years. With this rule change, the RIT-T framework was extended to include transmission asset replacements.

The process to be followed in undertaking the RIT-T is prescribed in the NER, AER RIT-T Guidelines and Industry practice application note (Asset replacement planning).

## A.2. RIT-T Requirement

The purpose of the regulatory investment test for transmission is to identify the credible option that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the market (the preferred option)[34]. AusNet Services must apply the RIT-T for all transmission asset replacement projects except in the circumstances where;

- The asset replacement is required to address an urgent and unforeseen network issue[35]
- The estimated capital cost of the most expensive technically and economically feasible option is less than $8 million[36]
- The proposed expenditure relates to maintenance and is not intended to augment the transmission network or replace network assets

## A.3. Need Identification

The starting point is a clearly identified need for action to be taken. An identified need is to be expressed as the achievement of a desired objective or end, and not simply the means to achieve a desired objective or end. A description of an identified need does not mention or explain a particular method, mechanism or approach to achieving a desired outcome. In describing an identified need it is useful to explain what may happen if AusNet Services fails to take any action.

[34] NER - Clause 5.16.1 (b)
[35] NER – Clause 5.16.3 (b)
[36] RIT-T thresholds are effective as at 1 Jan 2025, thresholds reviewed by the AER every 3 years – Clause 5.15.3 (a) of the NER

# A.4. Credible Options

The options that may be available to respond to the identified need must be assessed and compared to determine which achieves the test criterion.

Clause 5.15.2 (a) of the NER defines a credible option as an option (or group of options) that;

- addresses the identified need;
- is (or are) commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need

Clause 5.15.2 (b) of the NER requires AusNet Services to consider all options that could reasonably be classified as credible options. Clause 5.15.2 (d) states that the absence of a proponent does not exclude an option from being considered a credible option.

The AER RIT-T application guidelines states that "The AER is of the view that a TNSP has to consider a sufficient number and range of credible options, where the number of credible options being assessed regarding a particular identified need is proportionate to the magnitude of the likely costs of any credible option".

# A.5. Project Specification Consultation Report (PSCR)

Consultation with stakeholders is a key focus of the RIT-T, particularly to support that proponents of non-network solutions have the opportunity to contribute to the development and assessment of options.

If a transmission asset replacement project is subjected to a RIT-T, AusNet Services must consult all Registered Participants, AEMO, VicGrid and interested parties on the RIT-T project[37]. AusNet Services must prepare a Project Specification Consultation Report (PSCR) containing all the information required under clause 5.16.4 (b) of the NER.

The PSCR must be made available to all registered Participants, AEMO, VicGrid and other interested parties. AusNet Services must also provide a summary of the PSCR to AEMO within 5 business days of its release, and AEMO must publish the summary on its website within 3 working days. Upon request by an interested party, AusNet Services must provide a copy of the PSCR to that person within 3 business days of the request.

The consultation period on the PSCR must be not less than 12 weeks from the date AEMO publishes the summary of the PSCR on its website[38].

# A.6. Project Assessment Draft Report (PADR)

AusNet Services assessments on how the consultation has affected its initial assessment of the options is then reported back to stakeholders in a Project Assessment Draft Report (PADR).

Within 12 months of the end date of the PSCR consultation period, AusNet Services must prepare and publish a PADR having regard to the submissions received and meeting the information requirements specified in the clause 5.16.4

[37] NER – Clause 5.16.4
[38] NER – Clause 5.16.4 (g)

(k) of the NER. The PADR must be made available to all Registered Participants, AEMO, VicGrid and other interested parties.

AusNet Services must also provide a summary of the PADR to AEMO within 5 business days of its release, AEMO must publish the summary on its website within 3 working days. Upon request by an interested party, AusNet Services must provide a copy of the PADR to that person within 3 business days of the request.

The consultation period on the PADR must be no less than 6 weeks from the date AEMO publishes the summary of the PADR on its website[39].

Within 4 weeks after the end of the consultation period, at the request of an interested party, a Registered Participant or AEMO, AusNet Services must meet with the relevant party if a meeting is requested by two or more relevant parties and may meet with a relevant party if, after having considered all submissions, AusNet Services, acting reasonably, considers that the meeting is necessary[9].

### A.6.1. Exception from PADR

AusNet Services does not have to prepare a PADR if;

1. The estimated capital cost of the preferred option is less than $54 million; and

2. The preferred option and any other credible option have no material market benefit; and

3. AusNet Services has identified its preferred option in the PSCR and is still the preferred

option; and

4. Submissions on the PSCR did not identify any additional credible options which could deliver a material market benefit.

Under these circumstances AusNet Services could skip the preparation of the PADR and could prepare the PACR directly.

# A.7. Project Assessment Conclusion report (PACR)

After the end of the consultation on the PADR, and as soon as practical, AusNet Services must prepare and publish a Project Assessment Consultation Report (PACR), having regard to the submissions received and the matters discussed at any meetings held, and make this available to all Registered Participants, AEMO, VicGrid and interested parties.

AusNet Services must provide a summary of the PACR to AEMO within 5 business days of its release, and AEMO must publish the summary on its website within 3 working days of receipt.  Upon request by an interested party, AusNet Services must provide a copy of the PACR to that person within 3 business days of the request.

After 30 days of the date of publication of the PACR, AusNet Services may request, in writing to the AER, that the AER make a determination as to whether the preferred option satisfies the RIT-T. The AER must, publish a determination within 120 business days of receipt of the request. (The relevant period of time in which the AER must make a determination is automatically extended by the period of time taken by AusNet Services to provide any additional information requested by the AER).

[39] NER – Clause 5.16.4 (r)

# A.8. Reapplication of the RIT-T

Subsequent to completing the test, circumstances may arise which affect the 'preferred' status of the preferred option.

The NER requires that AusNet Services must reapply the RIT-T for a project if there has been a material change in circumstances resulting in the preferred option identified in the PACR being no longer the preferred option, unless otherwise determined by the AER.

# A.9. Dispute Process

The RIT-T process supports accountability of AusNet Services by providing for stakeholders to dispute its conclusions on the preferred option.

Within 30 days of the date of publication of the PSCR, Registered Participants, the AEMC, Connection Applicants, Intending Participants, AEMO, VicGrid and interested parties may, by notice to the AER, dispute conclusions made in the PACR[40].

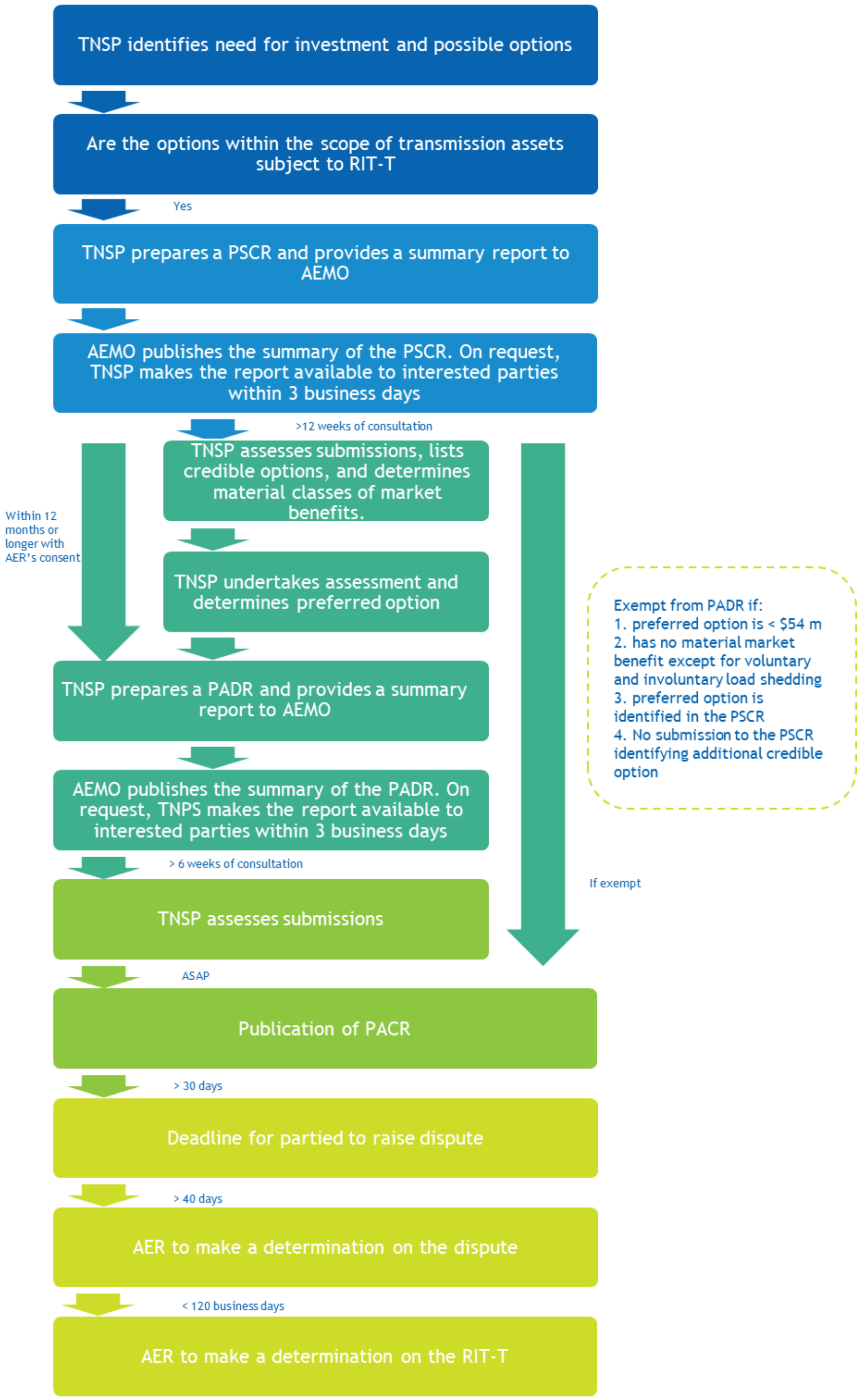
Within 40 days of receipt of the dispute notice or within an additional period of up to 60 days where the AER notifies interested parties that the additional time is required to make a determination because of the complexity or difficulty of the issues involved, the AER must either; reject any dispute and notify the person initiated dispute and AusNet Services or make and publish a determination directing AusNet Services to amend the matters set out in the PACR.

AusNet Services must comply with an AER determination within a timeframe specified by the AER in its determination.

[40] NER – Clause 5.16.5 (a)

# A.10. RIT-T Process

The following figure demonstrates the RIT-T assessment and consultation process that applies to transmission asset replacements.



# A.11. Valuing emissions reduction

## A.11.1. Methodology

Valuing greenhouse gas (GHG) emissions is a critical step in asset design, option analysis and climate target planning. The methodology involves estimating the greenhouse gas impact of an asset over the project life and multiplying this with carbon prices, as outlined by the Australian Energy Regulator (AER) who has prescribed a formal methodology for valuing greenhouse gas emissions reductions in its May 2024 Final Guidance. This methodology is now embedded in regulatory processes under the National Electricity Law, following amendments to include emissions reduction as part of the national energy objectives.

The AER uses interim Value of Emissions Reduction (VER) derived from a method agreed upon by Energy Ministers (outlined in the MCE Statement). These values are expressed in real 2023 AUD per tonne of $CO_2e$ and apply on a calendar year basis. VERs are to be used in financial models and cost-benefit analyses for regulatory investment tests (RITs).

The value of greenhouse gas emissions reduction is the 2022-2023 average of the generic Australian Carbon Credit unit spot price (AUD$33/tonne CO2-e) with a growth rate of 10% p.a. averaged with a linear interpolation of:

(1) From 2024-2029: the IPCC Fifth Assessment Report Representative Concentration Pathway 2.6 (commonly referred to as RCP2.6) scenario, median marginal cost of abatement figures, converted into 2023 AUD dollars.

(2) From 2030-2050: the IPCC Sixth Assessment Report Category 2 (commonly referred to as C2) emissions scenario median marginal cost of abatement figures, converted into 2023 AUD dollars.

For years included in assessment beyond 2050, the 2050 value should apply[41].

| Year | Average IPCC & ACCU (using official IPCC) AUD 2023 |
|---|---|
| 2023 | 66 |
| 2024 | 70 |
| 2025 | 75 |
| 2026 | 80 |
| 2027 | 84 |
| 2028 | 89 |
| 2029 | 95 |
| 2030 | 105 |
| 2031 | 114 |
| 2032 | 124 |
| 2033 | 135 |
| 2034 | 146 |
| 2035 | 157 |
| 2036 | 169 |
| 2037 | 181 |
| 2038 | 194 |
| 2039 | 207 |
| 2040 | 221 |
| 2041 | 236 |

[41] Valuing emissions reduction – AER guidance and explanatory statement May 2024

| | |
|---|---|
| 2042 | 252 |
| 2043 | 268 |
| 2044 | 286 |
| 2045 | 305 |
| 2046 | 325 |
| 2047 | 346 |
| 2048 | 369 |
| 2049 | 393 |
| 2050 | 420 |

# B. Abbreviations

| | |
|---|---|
| AEMO | Australian Energy Market Operator |
| AIS | Availability Incentive Scheme |
| ALCC | Annual Levelised Capital Cost |
| CRF | Capital Recovery Factor |
| EAR | Energy at Risk |
| ENPV | Expected Net Present Value |
| EUE | Expected Unserved Energy |
| MTTF | Mean Time To Failure |
| MTTR | Mean Time To Recovery |
| NPV | Net Present Value |
| POE | Probability of Exceedance |
| PVF | Present Value Factor |
| STPIS | Service Target Performance Incentive Scheme |
| TNSP | Transmission Network Service Provider |
| VCR | Value of Customer Reliability |

# C. Transmission Network Planning Assumptions

| Parameter | Value |
|---|---|
| VCR | Use latest rates for each terminal station. |
| Expected Unserved Energy (EUE) and Energy at Risk (EAR) and Market impact cost | EUE = EAR x P(down state)<br>Market impact cost to include impact on wholesale market, i.e. incremental fuel cost when generation is constraint off and the cost of ancillary services such as voltage control, system strength, inertia, etc. |
| Summer and Winter periods and Load Profiles | Summer Period is defined from 1 October to 31 March and Winter Period from 1 April to 30 September. The following periods are used for the respective profiles to account for the change in load patterns.<br>• Summer profile of 2023/24 for Summer POE50<br>• Summer profile of 2019/20 for Summer POE10<br>• Winter Profile of 2023 (Winter POE50 and POE10) |
| POE10 and POE50 Weighting | 30% of POE10 EUE and 70% of POE50 EUE |
| Transformer failure rates and MTTR P(Transformer down) | Failure rates as per the Transformer Risk Model<br>• B Transformers: MTTR as per Transformer MTTR_Final Spreadsheet.<br>• A, H and M Transformers:<br>  o MTTR when a spare is available = 3 months<br>  o MTTR when no spare is available = 18 to 24 months<br>(KTS A transformer took 12 months and we had a spare winding available; replacement with spare single phase on site at KTS took one month)<br>P(down) = R/(T+R) = λ/(r+λ) |
| Circuit Breaker failure rates and MTTR P(CB down) | Failure rates as per the CB Risk Model<br>• 220kV CB Major Outage: 168 hrs<br>• 66kV CB Major Outage: 96 hrs (SPIE example)<br>• Minor Outage (isolate CB): 2 hrs<br>P(down) = R/(T+R) = λ/(r+λ)<br>Consider multiplying the CB failure rate with a 1.3 factor to reflect that a circuit outage can be caused by other systems (protection, CT, isolators, etc.). |
| Switching Supply Risk (Community Impact for 66 kV CB outages) | Bustie CB major failure will result in a 2 hour outage of two busses until supply can be restored. The 66 kV network is usually configured such that this will only result in 1/3 of total load being shed (rings supplied from different busbars). Calculation: 1/3 x MD x LF. |
| Environmental Risk | LG4C CBs or plant that contains large volumes of oil and which could pose an environmental risk. Environmental risk cost of $30 K for non PCB and smaller oil spills and $500K for major oil spills and oil containing PCB.<br>Major failure rate as per Asset Risk Model x Probability of environmental impact. Assume all explosive failures will result in an average environmental impact of between $30K and $100 K. Failure rate x $30 K to $100 K. |

<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>Health and Safety Risk</td><td>
The reference safety probabilities given in the DNO Common Network Asset Indices Methodology<br><br>
The value of statistical life of $5.3m in 2022 dollars ($5.9 M escalated to 2024 dollars) , as per the Best Practice Regulation Guidance Note Value of Statistical Life Best Practice Regulation Guidnace Note Value of statistical life (pmc.gov.au)<br><br>
The value of lost time accident of $219,186 (escalated to March 24) per event for Electricity, Gas, Water and Waste Services, as per Safe Work Australia's The Cost of Work-related Injury and Illness for Australian Employers, Workers and the Community (2012-13), Table 2.3b.  CPI escalation from Dec 2008 to March 2024 = 137.4/ 92.4= 1.49
<table>
<tr><th rowspan="2">Industry division</th><th colspan="3">Total Cost ($ million)</th><th colspan="3">Distribution (%)</th><th>Unit Cost</th></tr>
<tr><th>Injury</th><th>Disease</th><th>Total</th><th>Costs</th><th>Cases</th><th>Workforce</th><th>$/case</th></tr>
<tr><td>Manufacturing</td><td>4 400</td><td>4 200</td><td>8 600</td><td>14</td><td>16</td><td>9</td><td>85,900</td></tr>
<tr><td>Health and Community Services</td><td>3 300</td><td>3 700</td><td>7 000</td><td>11</td><td>12</td><td>11</td><td>97,700</td></tr>
<tr><td>Construction</td><td>3 400</td><td>3 000</td><td>6 400</td><td>11</td><td>9</td><td>9</td><td>110,600</td></tr>
<tr><td>Retail Trade</td><td>2 200</td><td>3 100</td><td>5 300</td><td>9</td><td>8</td><td>11</td><td>115,200</td></tr>
<tr><td>Transport and Storage</td><td>2 500</td><td>2 200</td><td>4 700</td><td>8</td><td>7</td><td>5</td><td>105,800</td></tr>
<tr><td>Property and Business Services</td><td>2 400</td><td>2 300</td><td>4 700</td><td>8</td><td>11</td><td>9</td><td>71,700</td></tr>
<tr><td>Education</td><td>1 700</td><td>2 400</td><td>4 100</td><td>7</td><td>6</td><td>8</td><td>103,700</td></tr>
<tr><td>Government Administration and Defence</td><td>1 600</td><td>1 700</td><td>3 300</td><td>6</td><td>7</td><td>10</td><td>78,000</td></tr>
<tr><td>Personal and Other Services</td><td>1 400</td><td>1 500</td><td>2 900</td><td>5</td><td>5</td><td>4</td><td>104,600</td></tr>
<tr><td>Wholesale Trade</td><td>1 700</td><td>900</td><td>2 600</td><td>4</td><td>5</td><td>4</td><td>93,600</td></tr>
<tr><td>Accommodation, Cafes and Restaurants</td><td>1 300</td><td>1 000</td><td>2 300</td><td>4</td><td>4</td><td>7</td><td>94,500</td></tr>
<tr><td>Agriculture, Forestry and Fishing</td><td>1 200</td><td>900</td><td>2 100</td><td>3</td><td>3</td><td>3</td><td>126,100</td></tr>
<tr><td>Mining</td><td>1 100</td><td>700</td><td>1 800</td><td>3</td><td>2</td><td>2</td><td>170,000</td></tr>
<tr><td>Cultural and Recreational Services</td><td>800</td><td>600</td><td>1 400</td><td>2</td><td>2</td><td>2</td><td>106,100</td></tr>
<tr><td>Finance and Insurance</td><td>600</td><td>700</td><td>1 300</td><td>2</td><td>1</td><td>4</td><td>157,100</td></tr>
<tr><td>Communication Services</td><td>500</td><td>600</td><td>1 100</td><td>2</td><td>1</td><td>2</td><td>175 200</td></tr>
<tr><td>Electricity, Gas and Water Supply</td><td>600</td><td>400</td><td>1 000</td><td>2</td><td>1</td><td>1</td><td>147,400</td></tr>
<tr><td>Australia</td><td>30 700</td><td>29 900</td><td>60 600</td><td>100</td><td>100</td><td>100</td><td>99,100</td></tr>
</table>
[a] Units are rounded to the nearest $100 million<br>
A disproportionality factor of 3 for a single fatality of either a member of the public or a worker<br>
• Power Transformer Bushings: 5%;<br>
• Instrument Transformers: 10% for 220 kV ITs and 5% for 66 kV ITs<br>
• Circuit Breakers[42]: 5% 220 kV CBs and 5% for 66 kV CBs
</td></tr>
<tr><td>Plant Collateral Damage Risk and Financial Risk (clean up, media liaison, litigation, operational action (RTS), etc.)</td><td>
Average of [  C.I.C  ] per event<br>
Major failure rate as per Risk Model x Probability of an explosive failure as per following explosive failure probabilities<br>
<u>Explosive failure probabilities for plant where failure could involve fire and explosion (porcelain bushings and oil):</u><br>
Power Transformer Bushings: 5%; Instrument Transformers: 5% for 220 kV ITs and 5% for 66 kV Its; Circuit Breakers[43]: 5% 220 kV CBs and 5% for 66 kV CBs
</td></tr>
<tr><td>Reactive Asset Replacement Financial Risk</td><td>Major asset failure rate x Emergency Replacement cost of asset</td></tr>
<tr><td>New Plant Failure Rates</td><td>New technology switchgear does not exhibit explosive failure characteristic.</td></tr>
</table>

[42]Bulk oil and minimum oil CBs could pose safety, environmental and plant collateral damage risks; SF6 type CBs could pose environmental risk (safety and collateral damage risks are negligible), all safety, environmental and plant collateral damage risks are negligible for vacuum type CBs.

[43]Bulk oil and minimum oil CBs could pose safety, environmental and plant collateral damage risks; SF6 type CBs could pose environmental risk (safety and collateral damage risks are negligible), all safety, environmental and plant collateral damage risks are negligible for vacuum type CBs.

<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>Operation and Maintenance Cost</td><td>220 kV CB: Existing = [ C.I.C ]; New = [ C.I.C ]<br>66 kV CB: Existing = [ C.I.C ]; New = [ C.I.C ]<br>22 kV CB: Existing = [ C.I.C ]; New = [ C.I.C ]<br>220/66 kV Transformer: Existing = [ C.I.C ]; New = [ C.I.C ]<br>Use the incremental benefits in the economic evaluation, i.e. Existing O&M cost – new O&M cost.<br>Existing assets include assets currently in service while new assets include assets being put into service.</td></tr>
<tr><td>Sensitivity Studies</td><td>Test sensitivity of economic timing for input assumptions such as plant failure rates (0.75 and 1.25 times base case), VCR (0.75 and 1.25 times base case), Demand Growth, Discount Rate, etc.</td></tr>
<tr><td>Real Discount Rate</td><td>Uses the pre-tax real discount rates provided in AEMO's 2025 IASR.<br><br>Table 24 Pre-tax real discount rates<br><table><tr><th></th><th>Lower bound</th><th>Central estimate</th><th>Upper bound</th></tr><tr><td>2024 ISP</td><td>3.0%</td><td>7.0%</td><td>10.5%</td></tr><tr><td>Draft 2025 IASR</td><td>3.0%</td><td>7.0%</td><td>10.0%</td></tr></table><br>7% for the Base Case – commercial rate. Sensitivity studies at 3% and 10%.</td></tr>
<tr><td>Converting PV to annualized cost</td><td>PMT (payment for a loan based on constant payments and a constant interest rate). Assume 45 Years for the asset life</td></tr>
<tr><td>Converting PMT to PV cost</td><td>PV function. Assume 45 Years for the asset life</td></tr>
<tr><td>Emergency circuit breaker and Transformer replacements for the "Run to Failure" Option</td><td>Unplanned and emergency replacement will have a higher cost than planned replacements as resources need to be mobilised and work need to be reprioritised to deal with the emergency. It is prudent to allow for an increase in cost in the order of 20% to 30%. This is factored in as the emergency asset replacement<br>Also the country and metro spare transformers are "special" transformers to allow for their deployment at any site. This can b yeahe accounted for by allowing an additional [ C.I.C ] in the economic evaluation, because it has been proven that it is more economical to retain them at the terminal station after the emergency replacement.</td></tr>
</table>

# D. Connection Network Economic Evaluation

This appendix provides details of the calculation of expected unserved energy benefits associated with replacement of 66kV circuit breakers at terminal stations and station black scenarios.

## D.1. Circuit Breakers

The net benefits (calculated both before and after replacement) associated with replacement of transformer circuit breakers can be calculated as follows (it is assumed that a circuit breaker can be replaced in 96 hours following a major failure):

Annual EUE = Circuit breaker failure rate x 96 hours/8760 hours X N – 1 energy at risk.

**Example:**

A circuit breaker with a 5% probability of a major failure in a station where the N – 1 energy at risk is 1000 MWh has an expected un-served energy of 0.55 MWh (0.05 x 96/8760 x 1000 = 0.55)

Once the circuit breaker is replaced the major failure probability drops to 0.1% so the residual EUE is 0.01 MWh (0.001 x 96/8760 x 1000 = 0.01).

The net benefit is 0.54 MWh. This can be valued at VCR for that station.

## D.2. Feeder Circuit Breakers

Significant benefits are only evident for loops with only two 66kV circuit breakers. Generally, loops with three or more 66 kV circuit breakers will be able to supply most if not all load under N – 2 for most of the time so the expected unserved energy will be small and not worth including.

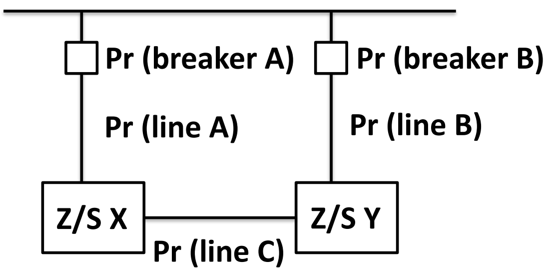
The net benefits (calculated both before and after replacement) associated with replacement of feeder circuit breakers for two line loops can be calculated as follows (It is assumed that a circuit breaker can be replaced in 96 hours following a major failure):

Annual EUE =

[Pr (circuit breaker A) + Pr (line A)] x [Pr (circuit breaker B) + Pr (line B)] x annual loop energy

+ [Pr (circuit breaker A) + Pr (line A)] x Pr (line C) x annual Z/S X energy

+ [Pr (circuit breaker B) + Pr (line B)] x Pr (line C) x annual Z/S Y energy




Where:

Pr(circuit breaker A) = unavailability of circuit breaker A = Failure rate x 96/8760, Pr (line A) = unavailability for line A = Urban 66kV lines are on average un-available for 2 hours per annum and rural 66kV lines are unavailable for 4 hours per annum (source 2012-2016 Distribution System Planning Report (DSPR) page 25). i.e. 2/8760 for urban lines and 4/8760 for rural lines.

**Example:**

Two circuit breakers (A and B) are being replaced which supply an urban loop where A has a probability of a major failure of 3% and B at 6%. The total loop load is on average 60 MW for this loop with average load of 20 MW at Z/S X and 40 MW at Z/S Y. Average loop/zone sub load can be calculated as 60% of maximum demand forecast. Maximum demand forecasts are available for all 66kV loops from the DAPR for the relevant Distributor and is available on the internet.

Annual EUE =

(0.03 x 96/8760 + 2/8760) x (0.06 x 96/8760 + 2/8760) x 60 x 8760 = 0.000557 x 0.000886 x 60 x 8760= **0.259 MWh**

+ (0.03 x 96/8760 + 2/8760) x (2/8760) x 20 x 8760 = 0.000557 x 0.000228 x 20 x 8760 = **0.022 MWh**

+ (0.06 x 96/8760 + 2/8760) x (2/8760) x 40 x 8760 = 0.000886 x 0.000228 x 40 x 8760 = **0.071 MWh**

Total Expected Unserved Energy = 0.259 + 0.022 + 0.071 = **0.352 MWh**

After replacement with circuit breakers with a 0.1% probability of failure this drops to 0.059 MWh so the net benefit is 0.293 MWh which can be valued at VCR.

# D.3. Bus tie Circuit Breakers

The calculation of benefits for bus tie circuit breakers depends on whether the bus tie is in a two or three tied buses arrangement. For normally open bus tie circuit breakers no expected un-served energy benefit is available as no load would normally be lost for failure of that circuit breaker.

For bus tie circuit breakers that tie two buses arranged as a group of just two buses a major failure of that circuit breaker is expected to result in all load being lost for both buses. It is expected that the load can be recovered in 2 hours by cutting away connections to the failed circuit breaker to allow buses to be restored to supply.

Annual EUE = Circuit breaker failure rate x 2hours/8760hours x annual bus energy.

**Example:**

For a normally closed bus tie circuit breaker connecting two buses that has a failure probability of 3% and average load of 150 MW the EUE is:-

Annual EUE = 0.03 x 2/8760 x 150 MW x 8760 = 9 MWh.

After the bus tie is replaced with a circuit breaker with a 0.1% probability of failure this drops to 0.3 MWh so the net benefit is 8.7 MWh which can be valued at VCR.

For a normally closed bus tie circuit breaker that connects buses arranged with three tied buses the load connected only to those two buses would be lost. 66kV loops connecting to the remaining bus would remain on load although lines connecting to the two lost buses would be disconnected.

The calculation is similar except only the lost load is considered rather than the whole bus load. (If the individual bus bar loads are not known, it can be assumed that 1/3 of the total station load will be lost for a three busbar station).

**Example:**

For a normally closed bus tie circuit breaker connecting two buses that has a failure probability of 3% and average load of 60 MW in only those loops connecting to the two lost buses the EUE is:

Annual EUE = 0.03 x 2/8760 x 60 MW x 8760 = 3.6 MWh.

After the bus tie is replaced with a circuit breaker with a 0.1% probability of failure this drops to 0.12 MWh so the net benefit is 3.48 MWh which can be valued at VCR.

# D.4. Station Black Calculation

The calculation of benefits for station black scenarios wherein all the transformers in the station fail utilised the Summer Probability of Exceedance 50 (POE50) demand and a load factor of 0.65.

**Example:**

For a three-transformer station with a failure probability of 3% each and a summer POE50 of 250MW and a MTTR (Mean Time To Repair) of 12 months, the EUE is:

Annual EUE = (0.03*0.03*0.03) x 0.65 x 12/12 x 250 MW x 8760 = 38.4 MWh.

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