AMS - Electricity Transmission Network

Asset Renewal Planning Guideline

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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 more than 2.4 million Victorian households and businesses with more than 6,500 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 demand of 10, 603 MW on 29 January 2009, which is the highest system demand recorded to date.

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

3.1 Victorian Planning Framework

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

- AEMO, which is the body solely responsible for planning the shared transmission network[1] and procuring network support and shared network augmentations;
- 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 industrial 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 1.

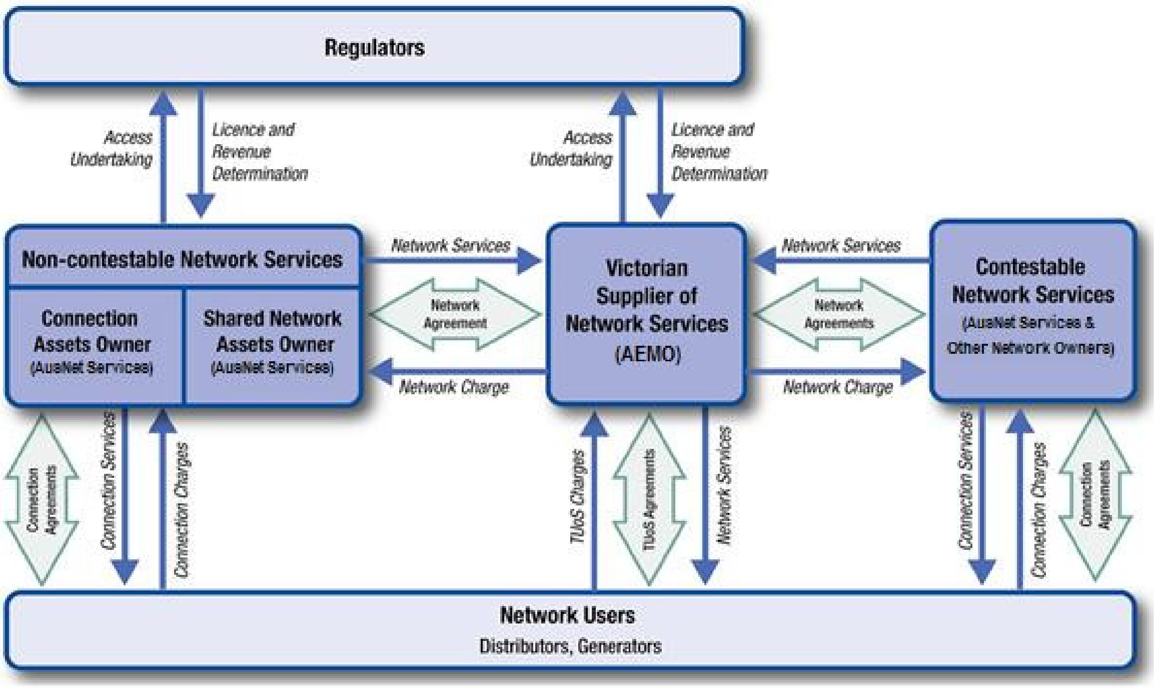


Figure 1: Regulatory and commercial relationships

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.

4 Economic and Technical Regulation

The National Electricity Law (NEL) contains two overarching principles that the AER applies when performing their 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 and repeated below:

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:

- price, quality, safety, reliability and security of supply of electricity; and
- the reliability, safety and security of the national electricity system.

The AER also takes into account the revenue and pricing principles of the NEL when making a transmission determination[2]. These principles require a TNSP to be provided with an opportunity to recover at least its efficient costs, and incentives to promote economic efficiency.

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”[3].

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”[4]

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

5 Asset Management Policy and Strategy

AusNet Services’ Asset Management Policy[5] directs the content and implementation of asset management strategies, objectives and plans for AusNet Services’ energy delivery networks. It

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 SP AusNet’s Asset Management Policy (April 2013)

guides employees, contractors, suppliers and delegates in each asset management decision to achieve AusNet Services' objective:

"Provide our customers with superior network and energy solutions".

The Asset Management Policy states that sound risk management and the continuous improvement practices of AusNet Services' integrated safety, health, environment, quality and asset management systems will manage the complete life cycle of network assets. The Asset Management Policy highlights the following focus areas:

- Hazards and risks to the safety of any person and their property will be minimised "so far as is practicable".
- Provide consumers with information, tools and service options to facilitate their energy choices.
- Effective consultation with stakeholders to comprehend and integrate their requirements in asset management decisions.
- The specification and application of assets will comply with legislation, regulation, Australian Standards and industry codes.
- The national energy laws, rules and their fundamental price, performance and security principles will guide service development in the interests of customers.
- Innovation and technology will be embraced to economically reduce service risks, increase service value and manage service performance commensurate with customer's emerging needs.
- Skilled people will be developed and deployed to sustainably manage risks, increase the value of services and improve the range of services.
- Energy network development will balance the environmental, economic, and social needs of today without sacrificing the interests of future generations
- Practices, systems and facilities will continuously improve commensurate with certification to a recognised asset management standard.

Asset Management Strategy AMS 10-01 documents AusNet Services' holistic approach to the management of the network assets, and establishes the linkages with and between 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.

The provision of a superior network requires the management of network assets over their lifecycle. This will be achieved by sound risk management and continuous improvement practices of our integrated safety, health, environment, quality and asset management systems[6].

6 Asset Renewal Strategy

AMS 10-11 Asset Replacement and Refurbishment describes AusNet Services' strategy and approach to asset renewal as summarised in this section[7].

6.1 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
- Quality, reliability and security of supply performance risks
- Minimising total life cycle costs through the consideration of capital costs, operational costs, retirement costs and operational risk costs
- Minimising the 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

6.2 Asset Renewal Criteria and Drivers

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

6.2.1 Compliance

AusNet Services' network and asset management practice must comply with all relevant electricity transmission codes, licences, contracts and prescribed industry standards to ensure that the rights and benefits of other National Electricity Market (NEM) participants are not compromised. Currently, these obligations include 22 regulatory instruments involving some 350 mandatory

6 AMS 10-01

7 In the context of this document, the term 'renewal' is used to mean refurbishment or replacement.

obligations and 260 event driven obligations relevant to the Victorian electricity transmission network.

Of particular significance are several legislative obligations relating to worker safety. Under the Occupational Health and Safety Act AusNet Services is required to so far as is reasonably practicable maintain for employees a working environment that is safe and without risks to health. The Electricity Safety Act requires AusNet Services to operate its electricity transmission network to minimise, so far as is practicable, hazards to the safety of any person.

These Acts require AusNet Services to have regard to the likelihood, harm and what is known or should be known about safety hazards. AusNet Services must also consider the availability and suitability of ways to eliminate or mitigate safety hazards. AusNet Services is then further obliged to have regard to the cost of removing or mitigating the safety hazard or risk.

6.2.2 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, 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 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 Weighted Average Remaining Life (WARL) 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.

The performance of connection assets of direct connected customers, such as steel and aluminium producers, and generators has to be at a high standard to minimise outages, interruptions or availability constraints. For example, generators who are unexpectedly constrained from the market are exposed to financial losses.

6.2.3 Asset Condition

AMS 10-13 Condition Monitoring describes AusNet Services’ strategy and approach to monitoring the condition of assets as summarised in this section.

Asset condition is measured with reference to an asset health index, on a scale of 1 to 5. The 1 to 5 condition range is consistent across asset types and relates to the expected remaining asset life. The table below provides a simple explanation of the asset condition scores.

Condition Score	Likert Scale	Condition Description	Recommended Action	Remaining Service Potential%
C1	Very Good	Initial Service Condition	No additional specific actions required, continue routine maintenance and condition monitoring	95
C2	Good	Better than normal for age or refurbished		70
C3	Average	Normal condition for age		45
C4	Poor	Advanced Deterioration	Remedial action/replacement within 2-10 years	25
C5	Very Poor	Extreme deterioration approaching end of life	Remedial action/replacement within 1-5 years	15

Table 1: Condition score definition and recommended action

Asset 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 network 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.

Condition profiles for a fleet of assets, aid comprehension of the extent and the rate of deterioration. They also provide input to asset risk models used to compare future risk forecasts with historical and current risk positions.

Condition ranking each asset within a fleet of its peers, identifies individual assets having the greatest probability of failure and targets intensive inspection, testing and potentially, renewal activities.

6.2.4 Asset Criticality

The consequence of plant failures, including loss of service is established for each major asset and combined with the probability of such events to enable the evaluation of risk costs for individual assets. Asset condition and asset criticality are considered in 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 9.3 and includes loss of supply, health and safety impact, environmental impact and plant collateral damage.

Comparative assessments of asset fleet risk, based on individual asset probabilities and consequences of failure, are a valuable tool in determining the volume and timing of economic asset renewal activities.

Asset failure risk information flows from AusNet Services' condition based reliability centred maintenance (C-RCM) methodology to guide optimal replacement timing. This approach takes into account performance requirements and actual failure data to determine failure rates of individual network assets or classes of assets.

Failure Mode Effect Criticality Analysis (FMECA) based on historical asset performance data is undertaken to determine typical root causes of functional failures, and the resulting effects these causes have on key performance measures including network safety, reliability and availability. Asset condition data collected during scheduled maintenance tasks is used to determine dynamic time-based probability of failures and the remaining service potential of the asset in that lifecycle phase.

6.2.5 Life Cycle Costs

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

6.2.6 Future Customer Requirements

Asset renewal plans are integrated with the shared network augmentation plans developed by AEMO and the connection network augmentation plans developed by distribution network service providers to optimise economic benefits. The integration of these plans may advance or defer asset renewal plans or introduce new options to consider in the planning decision.

6.2.7 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 technical support and spares available from within AusNet Services and plant criticality to the network, this strategy may involve the replacement of one asset to generate spares for the maintenance of other assets in less critical areas of the network. This strategy generally results in an improvement in asset restoration time during a failure, but not to the overall network reliability and availability.

7 Asset Renewal Planning Process

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

1. Assess asset health and performance indices to calculate asset condition scores. Develop asset failure rate curves, establish assets remaining service potential and calibrate to history.

2. Quantify the base line risk based on the probability and consequence of asset failure and verify whether the base line risk has reached a level where a “Do nothing” asset management approach has become uneconomic. The main hazards or effects that should be included are safety, security of supply, environmental impact and collateral plant damage.

3. Develop asset replacement 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 outage requirements. Consider brownfield or greenfield type replacement, staged replacement, and refurbishment (opex) versus replacement (capex) trade-offs. Assess the need to undertake a regulatory investment test (RIT-T).

4. Develop scope of work and cost estimates for each credible option.

5. Select asset renewal solutions including deferred replacement when the base line risk is small and the asset can be managed without the need for refurbishment or replacement (“do nothing”). Run to failure should only be considered for assets that do not present significant safety or environmental hazards and whose failure can be rapidly and economically recovered.

6. Consult with AEMO and the respective Distribution Business regarding their long term augmentation plans and update ultimate planning requirements for terminal stations and transmission lines. Integrate asset renewal and augmentation projects and plans.

7. Select the most economical solution that complies with the asset management strategies and future augmentation planning requirements as well as network performance incentive schemes (Network Availability Incentive Scheme – AIS and Service Target Performance Incentive Scheme - STPIS). Ensure compliance with technical limits, planning philosophies, regulatory criteria and guidelines, reliability and quality of supply standards and asset management strategies.

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

9. Prepare an asset renewal planning report documenting all considerations and recommendations.

10. Prioritise the different transmission asset renewal projects based on the assessed failure risk, the company’s business strategy and regulatory funding decisions.

11. Integrated network plans and projects to ensure efficient project and program delivery

12. Document plan and initiate execution by recording the proposed projects in the Program/Project Life Cycle.

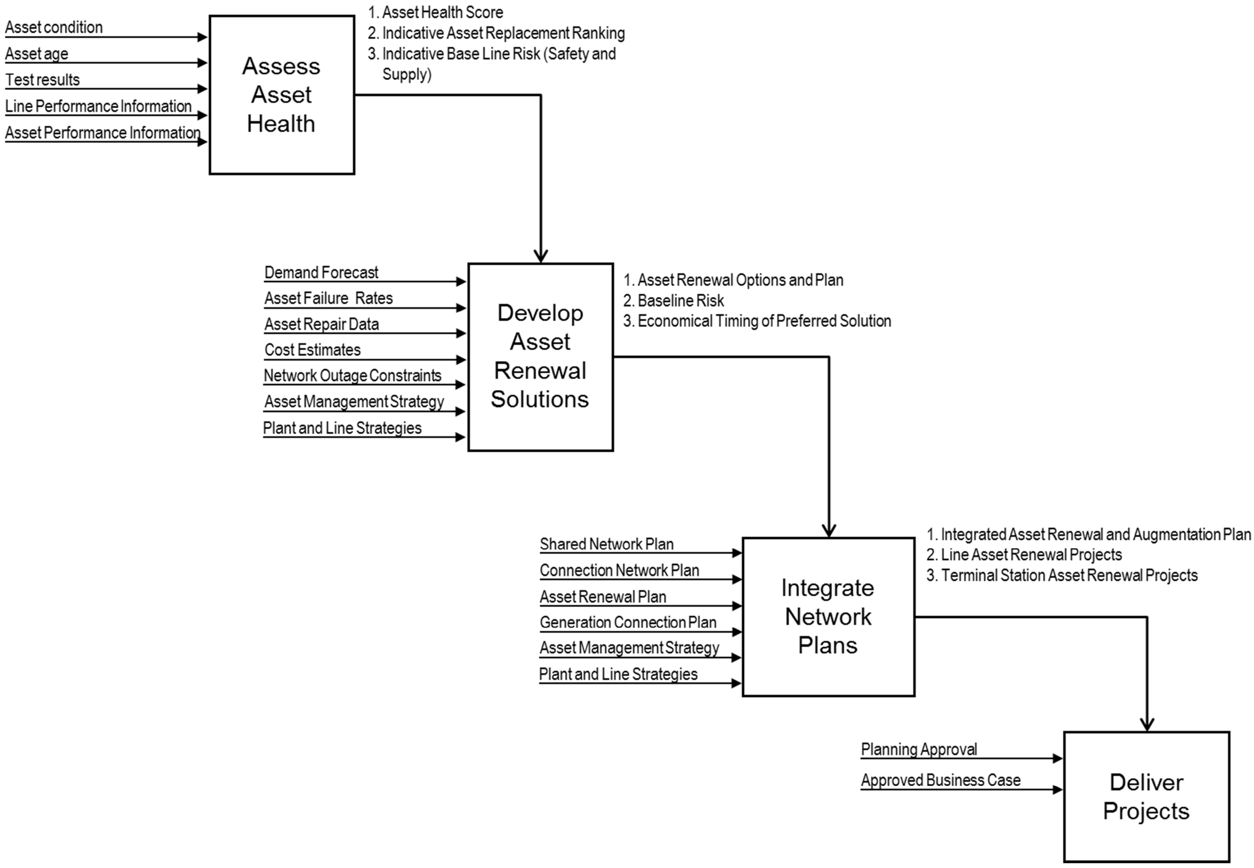


Figure 2: Asset Renewal Planning Process

8 Asset Renewal Options

AMS 10-11 Asset Replacement and Refurbishment describes AusNet Services' strategy and approach to asset renewal as summarised in this section. The asset renewal objectives described in Section 5.2 are met by either asset refurbishment or replacement, or a combination of refurbishment and replacement.

8.1 Refurbishment

This asset management strategy involves refurbishing plant to extend its reliable service life. This is sometimes the most economical option. However, in many cases it is reliant on spare equipment being available while deteriorated plant is being refurbished and 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.

8.2 Replacement

This asset management strategy involves replacing plant to ensure 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 plant which can avoid costs associated with obsolete equipment and 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 refurbishment is simply an ineffective means for addressing poor reliability.

A primary requirement for asset replacement planning is knowledge of asset condition and other factors that will affect the remaining technical life of the assets. This technical life assessment is undertaken in accordance with AMS 10-101 Asset Life Evaluation Strategy.

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

The following options are considered in the asset renewal evaluation:

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.

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.

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.

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.

Replacement of Whole Station in Existing Location (Brownfield redevelopment) is employed when it is economic to replace all assets as part of 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.

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 Economic Planning Criteria

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.)
- Security of supply risk to consumers or the electricity market when asset failure could result in supply interruptions or network constraints
- 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 supply interruptions

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. Figure 3 illustrates the methodology used to calculate the baseline risk, which is the probability weighted risk cost presented by asset failure.

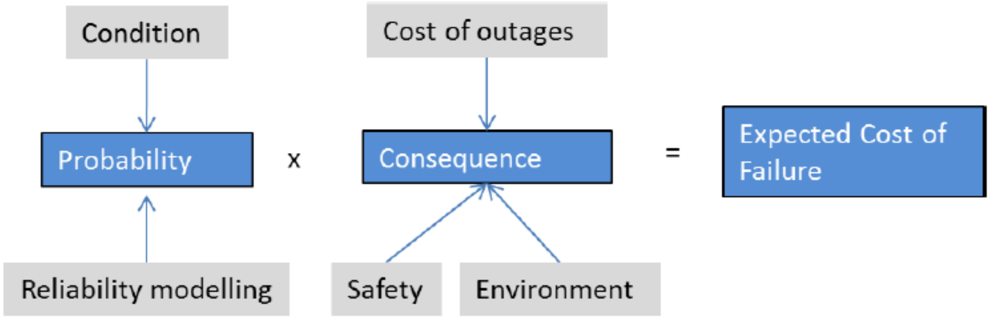


Figure 3: Baseline Risk Calculation

9.1 Identifying the assets at risk

Asset health index scores and asset failure rate curves are assigned to key assets, such as power transformers, circuit breakers and instrument transformers and documented in the risk models for these major assets.

The asset health index score provides an indication of asset health and candidates for replacement are first identified by ranking the assets with the highest condition scores (i.e. C4 and C5). The initial high level baseline risk calculation of an asset or group of assets provides evidence of the need for a more rigorous assessment.

Consultation with the asset management team and referring to the relevant AusNet Services Asset Management Strategy documents facilitates the process of pinpointing the assets at risk.

AusNet Services is obligated to consider the suitability of different options to mitigate safety hazards in switchyards and terminal stations; identifying the assets with explosive failure risks.

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 lowest expected present value (PV) cost and the timing by when the asset renewal would be economical.

9.2 Asset Unavailability

Asset unavailability is calculated from the asset failure rate and mean time to repair information for the particular asset. The asset failure rate information for transformer, circuit breakers and instrument transformers are described in the failure rate curves in the risk models for these assets.

The following definitions are used to define asset unavailability:

- Failure Rate ($\lambda(t)$) is defined as the anticipated number of times an item will fail in a specified time period, t.

- Mean time to Repair (MTTR) is defined as the total amount of time spent performing corrective repairs. It is the expected span of time from a failure (shut down) to the repair completion.
- Unavailability (Pr(f)) is the probability that the component is in the failed state.

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

Example:

A major outage 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 repair (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:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.217\%$$

9.3 Consequence of asset failure

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

- **Supply Security Risk:** Load at risk that would not be supplied in the event of an asset failure, evaluated based on AEMO’s terminal station demand forecast and the latest value of customer reliability (VCR). Network constraints (generation constraints) that also impact on the National Electricity Market (NEM) are assessed by AEMO through market simulations.
- **Health and Safety Risk:** Hazards to the safety of any person in an event of asset explosive failure, e.g. Human injury and fatality.
- **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.

9.3.1 Supply Security Risk

9.3.1.1. Demand Forecasts

AusNet Services uses the distribution businesses' terminal station demand forecast and AEMO's connection point forecast for asset replacement planning. These two demand forecasts provide the maximum active power and reactive power demands forecast to occur for summer and winter on average one year in two (50% probability of exceedance (POE)) and one year in ten (10% POE) for each of the financial years in the ten year planning period.

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

9.3.1.2. 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 benefit can be compared with the cost of the asset renewal.

AusNet Services uses the latest VCR rates derived by AEMO and as weighted by the DBs based on the load composition for each individual terminal station. The average VCR across Victoria for 2014 is $39 500/MWh[8] ($39.50/kWh).

Sector	**VCR for 2014 ($/kWh)** (Source: AEMO, VCR Review Final Report, September 2014)
Residential (Victoria)	24.76
Commercial (NEM)	44.72
Agricultural (NEM)	47.67
Industrial (NEM)	44.06[17]
Composite- all sectors	**39.50**

Table 2: 2014 Victorian VCR estimates by sector

9.3.1.3. Energy at Risk

Energy at risk (EAR) can be defined as the estimate of 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.

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

8 2014 Transmission Connection Planning Report

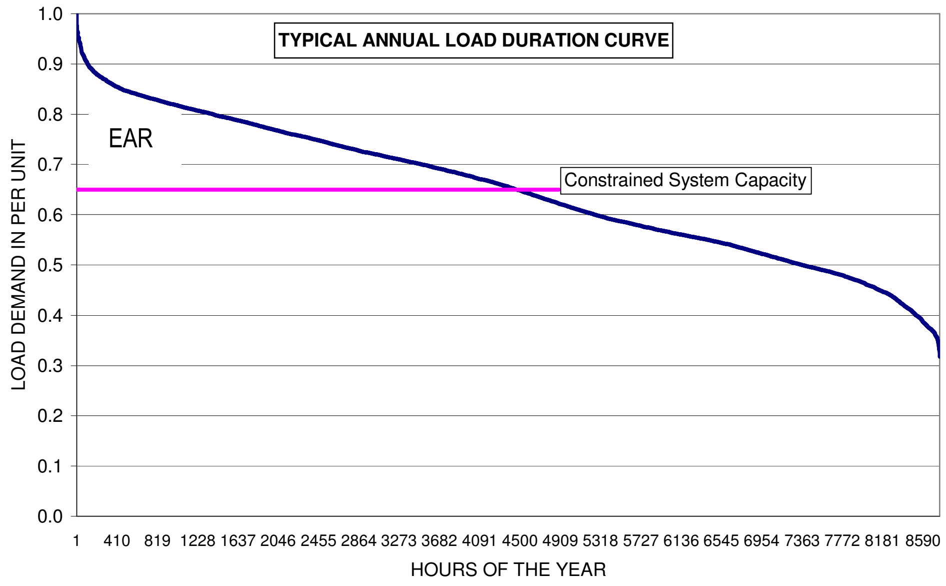


Figure 4: Illustration of the calculation of the EAR

9.3.1.4. 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 Terminal Station Demand Forecasts* include both 50% probability exceedence (POE50) of the maximum demand and 10% probability exceedence (POE10) of the maximum demand. The following weightings are applied to determine the EUE:

10%POE weighting = 0.30

50%POE weighting = 0.70

$$\mathbf{EUE} = \mathbf{EAR \times Pr\ (f)}$$

$$= [\mathbf{w_{10} x EAR_{D10} + w_{50} x EAR_{D50}}] \mathbf{\ x\ Pr\ (f)}$$

$$= [\mathbf{0.3x\ EAR_{D10} + 0.7x\ EAR_{D50}}] \mathbf{\ x\ Pr\ (f)}$$

Notations:

Pr (f) Probability of Failure

EAR Energy at Risk

w_{10} Weighting apply to 10%POE

w_{50} Weighting apply to 50%POE

EAR_{D10} Energy at Risk using 10%POE demand forecast

EAR_{D50} Energy at Risk using 50%POE demand forecast

9.3.1.5. Monetised Supply Security Risk

Unserved energy is valued using VCR, which is an estimation of the value that customers place on a reliable electricity supply or the value that customers place on avoiding electricity service interruptions.

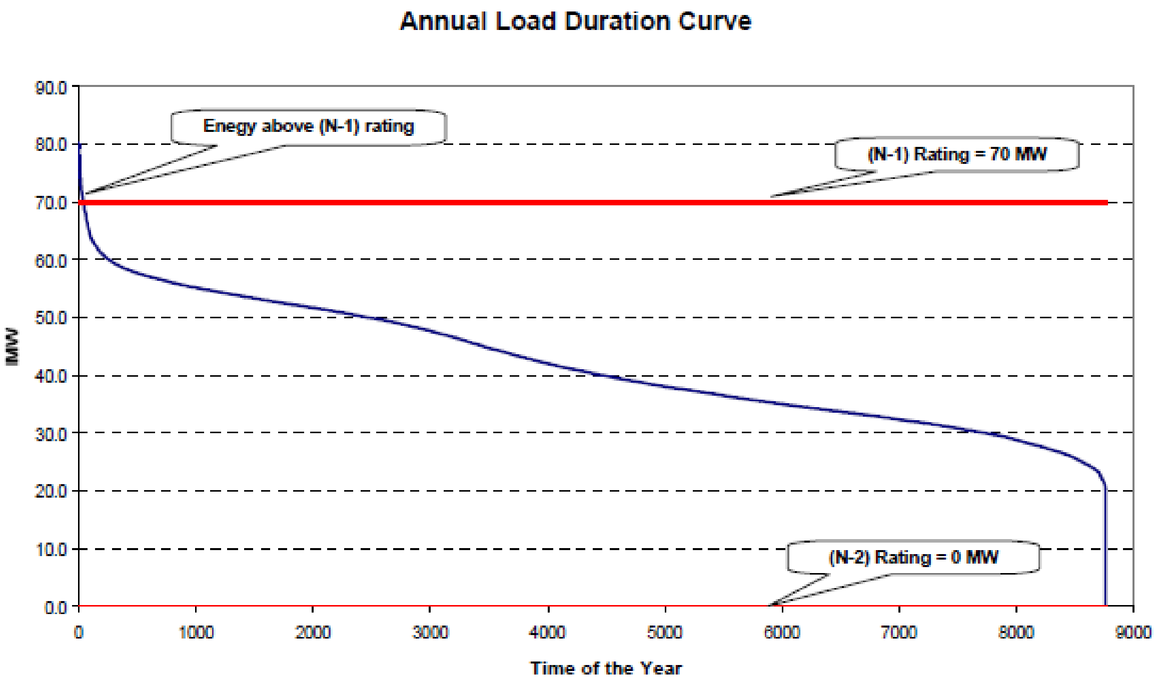
The monetised supply security risk is equivalent to the expected cost to consumers of having their electricity supply interrupted for a certain period of time and is sometimes referred to as the community cost.

Monetised Supply Security Risk = VCR x EUE

In the economic analysis for a particular 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.

Example:

The following example illustrates the methodology to calculate "Expected Unserved Energy" for a terminal station with two transformers with the annual load duration curve shown below:



Energy above N-1 rating = 132 MWh

Energy above N-2 rating = 367, 877 MWh

Unavailability Pr (f) of transformer A = 0.217%

Unavailability Pr (f) of transformer B = 0.217%

VCR = $30,000 per MWh

Risk assessment calculation:

First Order Contingency (N-1):

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

= 132 MWh x [0.217% + 0.217%]

= 0.6 MWh

Second Order Contingency (N-2):

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

= 367, 877 MWh x [0.217% x 0.217%]

= 1.7 MWh

Monetised Supply Security Risk = VCR x EUE

= $30,000 per MWh x [0.6MWh + 1.7 MWh]

= $69,000

9.3.2 Market Impact Cost

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

9.3.2.1. Market Dispatch Modelling

Market dispatch modelling has to be undertaken for the Regulatory Investment Tests for Transmission (RIT-T) to calculate the magnitude of market benefits, unless the transmission network service provider (TNSP) can demonstrate that generation dispatch and investments in the wholesale market are not a material factor in the ranking of options under the RIT-T[9].

The market dispatch modelling methodology requires calculation of the incremental market benefits by comparing the "state of the world" in the base case (the addition of no new or more restrictive constraints) with a state of the world for each of the credible options. The classes of market benefits considered in the 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.

The incremental market benefits for asset replacement involves comparing the market impact cost of the base case, with a particular part of the network out of service (OOS), with the market impact cost with all assets in service.

Several reasonable scenarios are considered to ensure 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) a realistic treatment of plant characteristics, including for example minimum generation levels and variable operation costs; and
>
> (b) a realistic treatment of the network constraints and losses,

The market modelling typically covers a period of ten years into the future. This is considered a period of sufficient length to cover the impact of changes in generation in Victoria (increase in wind and gas and reduction in traditional coal generators) yet short enough to minimise uncertainty around demand forecasts, new transmission augmentation projects, and new technologies such as solar photovoltaic cells, electric vehicles, and embedded storage that could otherwise skew market modelling results.

If the modelling needs to be extended beyond the ten year window, the market benefits calculated for the final year are held constant and applied as the assumed annual market benefit that would continue under the option in the future.

Models assume load and wind behaviour from a particular year and an assumption of the Short Run Marginal Cost (SRMC) bidding behaviour of generators. In addition to generator and load behaviour, the models include a set of National Electricity Market Dispatch Engine (NEMDE) pre-dispatch system normal constraints. New constraints are developed and modelled for the impact of the asset failure (for example, thermal, transient stability, or voltage collapse constraints for the loss of a line or transformation capacity).

AusNet Services does not have the resources and data to perform this modelling and rely on AEMO to perform these modelling studies. AEMO supplies AusNet Services with the market impact cost for up to ten years for both the 'System Normal Secure' and 'N-1 Secure' scenarios, which are then used to calculate the marginal market cost.

9 AER. Final Regulatory Investment Test for Transmission. June 2010, version 1, paragraph 11, p.6

Prophet by Intelligent Energy Systems[10] (IES) and PLEXOS® by Energy Exemplar[11] are the two models that are used for market modelling studies.

9.3.2.2. Market Impact Cost Example

The marginal market cost provided by AEMO is 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 9.2).

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 and for generation to be scheduled out of merit to ensure the remaining three 500/220 kV transformers are not overloaded.

Assumptions:
The mean time to repair (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:

$$\Pr(f) = \frac{MTTR}{MTTR + \frac{1}{\lambda}} = \frac{\frac{2.6}{12}}{\frac{2.6}{12} + \frac{1}{1\%}} = 0.217\%$$

An example of the marginal market cost (MMC) provided by AEMO is shown in **Table 3**.

Year	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
Marginal Market Cost ($,000)	1,220	1,111	902	2,284	4,553	9,708	12,226	10,882	19,746

Table 4: Marginal market cost (MMC) associated with the HWTS A4 transformer

Monetised Market Risk Cost (2013-14) = MMC (2013-14) x Pr(f)

10 Intelligent Energy Systems, http://www.iesys.com/ies/, accessed 23rd January, 2014.

11 Energy Exemplar, http://energyexemplar.com/, accessed 23rd January, 2014.

= $1,220,000 x 0.217%

= $2,647

9.3.3 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*.[12] What is considered "practicable" is determined by having regard to:

a) the severity of the hazard or risk in question; and

b) state of knowledge about the hazard or risk and any ways of removing or mitigating the hazard or risk; and

c) the availability and suitability of ways to remove or mitigate the hazard or risk; and

d) the cost of removing or mitigating the hazard or risk.[13]

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".*[14]

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:

a) the likelihood of the hazard or risk concerned eventuating;

b) the degree of harm that would result if the hazard or risk eventuated;

c) 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;

d) the availability and suitability of ways to eliminate or reduce the hazard or risk;

e) the cost of eliminating or reducing the hazard or risk.[15]

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12 Electricity Safety Act 1998 (Vic), section 98(a).

13 Electricity Safety Act 1998 (Vic), section 3.

14 Occupational Health and Safety Act 2004 (Vic), Section 21(1).

15 Occupational Health and Safety Act 2004 (Vic), Section 20(2).

The National Electricity Law requires that AusNet Services be permitted a reasonable opportunity to recover at least the efficient costs it incurs in complying with a regulatory obligation or requirement.[16] The efficient costs of minimising hazards and risks to workers in accordance with the requirements of the ESA and the OHSA are likely to be recoverable.

In practice this means safety risk should be proactively managed until the cost becomes grossly disproportionate to the benefits[17]. With respect to the management of safety risks which may cause a single fatality to a worker; application of the principle of "as low as reasonably practicable" indicates costs in excess of $ [C-I-C] may be disproportionate.

This estimate has been calculated by AusNet Services based on a methodology established in several government studies including by the UK's Health and Safety Executive and the New Zealand Government. The methodology estimates direct safety benefits and escalates this by a disproportionality factor of three to form an appropriate "cost of preventing a fatality" (CPF).

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

- An explosive failure could injure or kill contractors or staff on site with a consequence cost of $ [C-I-C][18]
- Plant that contains large volumes of oil poses an environmental risk with an average consequence cost of $30 K
- 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 $1 M per event

The likelihood of the above hazards are based on the major failure rates defined in the RCM models and the CIGRE research[19] into the probability of explosion and fire associated with major plant failures, which presents the probability of a major failure with safety, collateral plant damage or environmental consequences.

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

Example:

16 National Electricity Law, section 7A(2)(b).

17 Practical application of SFAIP in project specification 2012

18 Practical application of SFAIP in project specification SPI PowerNet 2012

19 Cigre Final Report of the 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment.

As described in AMS 10-64 Instrument Transformers, several explosive failures have confirmed that single-phase, porcelain clad, oil insulated current transformers present an unacceptable risk. This risk includes supply outages, collateral plant damage, environment damage and possible injury to staff. Twelve 66 kV current transformers at Fishermans Bend Terminal Station are targeted for replacement.

Assumptions:

Annual risk for twelve Current Transformers with a failure rate of 0.025 = 12 X 0.025 = 0.3

It is assumed that 1 in 10 major failures of the 66 kV Tyree current transformer will present a safety, environmental and collateral plant damage risk[20]. Probability of explosive failure = 0.1.

A site specific factor that reflects the proximity and likelihood that adjacent plant may be damaged of between 1 and 0 is used in the calculation; assume = 0.5.

Probability of environmental impact = 0.1.

Risk assessment calculation:

Safety Risk Cost	=	0.3 x 0.1 x $ [C-I-C]
Plant Damage Risk Cost	=	0.3 x 0.1 x 0.5 x $1M = $15K
Environmental Risk Cost	=	0.3 x 0.1 x $30 K = $0.9K

9.3.4 Network Performance Incentive Schemes

The transmission network has two performance incentive schemes, the Availability Incentive Scheme (AIS) and the Service Target Performance Incentive Scheme (STPIS). The Availability Incentive Scheme[21], is defined in the Network Agreement and is administered by AEMO.

The STPIS[22] 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.
- Network Capability Component ‐ provides an incentive to deliver benefits through increased network capability, availability or reliability through minor capex or opex projects.

20 Cigre Final Report of the 2004 – 2007 International Enquiry on Reliability of High Voltage Equipment; Part 4 – Instrument Transformers; October 2012. Two out of 15 instrument transformer major failures involved fire and explosion for oil/paper insulated instrument transformers.

21 Amendment Agreement to the Network Agreement with VENCorp 23 December 2002.

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

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

9.3.4.1. AEMO Availability Incentive Scheme

In 2002, AusNet Services and AEMO (then VENCorp) entered into an agreement (details are in the Network Agreement) forming the current Availability Incentive Scheme (AIS). The AIS is a Victorian jurisdictional scheme focussed on securing Victorian load and therefore AusNet Services is currently the only TNSP in the NEM subject to its application. This incentive scheme will, however terminate during the present regulatory control period.

AusNet Services receives revenue through its revenue determinations to fund its participation in the AIS. The scheme operates through AusNet Services paying AEMO a rebate each month which is based on prescribed outages that have occurred (both planned and unplanned). The rebate reflects the potential impact faced by network users whenever AusNet Services removes a prescribed network asset from service for maintenance or due to a forced outage.

The total rebate amount is calculated using specified hourly outage rates assigned to individual network elements or assets. Annual increases (z(t)) in hourly outage rebates are calculated from the Australian Consumer Price Index (CPI).

$$z(t) = \frac{CPI_t}{CPI_b}$$

CPI_t is the CPI for the calendar quarter ending 31 December immediately preceding the commencement of the Scheme Year. For example, Dec 2012 CPI was 102 and Dec 2013 CPI was 104.8. CPI_b is the CPI for the calendar quarter ending 31 December 2002, 77.6.

Hourly rates differ for specified peak, intermediate and off-peak periods.

- Period 1, being the Peak period, applies from the first Monday in November immediately preceding the 20th day of November, through to the first Friday in March immediately after the 11th of March. The Peak period applies on weekdays between 1100 and 2200. Public holidays, weekends and any time between 2201 and 1059 will be considered Off Peak (11% of the year).

- Period 2, being the Intermediate period is from the 1st of June through to the 31st of August inclusive, between the hours of 0700 and 2200. All weekends, public holidays and any time between 2201 and 0659 will be considered Off Peak (11% of the year).

- Period 3, being the off Peak period is all other times. This includes all weekends, public holidays and all days from the last weekday before Christmas Day to the first weekday after New Year's Day (78% of the year).

Hourly rates are calculated by AEMO based on the cost of an outage to network users in the event of a second contingency event occurring. The rebate reflects the potential impact faced by network users whenever AusNet Services removes a network element from service, and accounts for the following potential impacts:

- Loss of load to customers (costed at the value of loss of load - VCR); and

- Loss of generator access to market (costed at marginal cost of generator rescheduling).

Example:

One example of an outage is a failure resulting in an APD-HYTS No. 1 500 kV line outage. In the example the following definitions are made:

- Failure Rate ($\lambda(t)$) is defined as the anticipated number of times an item will fail in a specified time period, t.
- The mean time to repair (MTTR) is the time it takes to return the prescribed asset to service.

Assumptions:
Failure will result in a prescribed asset being out of service. Failure Rate ($\lambda(t)$) in a particular year is 5%. MTTR is 10 hours.

Incentive calculation:

Incentive Risk Cost = $\lambda(t)$ x MTTR x [(11% x Period1)+(11% x Period2)+(78% x Period3)]
= 5% x 10hrs x [(11%x$3309/hr)+(11%x$3191/hr)+(78%x$3124/hr)]
= 5% x 10hrs x [$3151/hr]
= $1.575k

Note 1: a single event outage rebate is limited.
Maximum Incentive Risk Cost =$1.2M x z(t)
(Single Outage 2013-14) = $1.2M x (102/77.6)
= $1,577.3k

Note 2: the maximum rebate is limited.
Maximum Incentive Risk Cost = $12M x z(t)
(Annual Rebate 2013-14) = $12M x (102/77.6)
= $15,773k

9.3.4.2. 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 5, where MAR is the maximum allowed revenue for the relevant calendar year[23].

Parameter	Weighting (MAR %)
Average circuit outage rate:	**0.50**
Line outage - fault	0.20
Transformer outage – fault	0.20
Reactive plant – fault	0.10
Line outage – forced outage	0.00
Transformer outage – forced outage	0.00
Reactive plant – forced outage	0.00
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 04, 20 December 2012, AER reference 45236-D12/137417)

Table 5: Weightings for each parameter/sub-parameter

Table 6 shows the caps, collars 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.
- Collar - 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.

23 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.

Parameter	Sub-parameters	Collar	Target	Cap
Average circuit outage rate	Line outage - fault	42.0%	25.9%	14.8%
	Transformer outage - fault	31.7%	16.1%	7.4%
	Reactive plant - fault	46.4%	35.1%	2.5%
Loss of supply event frequency	No. of events > 0.05 system mins	6	2	0
	No. of events > 0.30 system mins	2	1	0
Average outage duration	Average outage duration (mins)	293.5	98	5

Table 6: Caps Collars and Targets for service component (2014 to 2017)

Assuming an approximate MAR of $500M, the caps, collars and targets convert to a $ per incident shown in Table 7, Table 8, and Table 9. The $ per incident will be revised annually due to a variation in the MAR and the number of defined assets, so new figures should be obtained before they are included in the model.

Average Circuit Outage Rate	Defined Assets	Actual Incidents			$ per incident	
		Collar	Target	Cap	Exceede d target	Not yet hit target
Line outage - fault	120	50	31	18	51,760	75,075
Transformer outage - fault	119	38	19	9	53,868	96,590
Reactive plant - fault	70	32	25	2	63,211	21,911

Table 7: Parameter 1 average circuit outage rate (example)

Loss of supply event frequency	$ per incident	
	Exceeded target	Not yet hit target
No. of events > 0.05 system mins	187,500	375,000
No. of events > 0.30 system mins	375,000	750,000

Table 8: Parameter 2 loss of supply event frequency (example)

	$ per minute	
	Exceeded target	**Not yet hit target**
Average outage duration	5,115	10,753

Table 9: Parameter 3 average outage duration (example)

Example – Parameter 1:

One example of an outage is a circuit breaker failure resulting in a line outage. In the example the following definitions are made:

Failure Rate (λ(t)) is defined as the anticipated number of times an item will fail in a specified time period, t.

Assumptions:
A failure will result in a defined asset being out of service. Without this failure, AusNet Services will achieve its target performance. As a result, the 'exceeded target' column should be used. Failure Rate (λ(t)) in a particular year is 1%.

Parameter 1 incentive calculation:

Incentive Risk Cost	=	λ(t) x $ per incident
	=	1% x $51,760
	=	$0.517k

Note: the collar should not be exceeded (for line outages, 50). In numerical terms:

Maximum Incentive Risk Cost	=	(Collar – Target) x $ per Incident
(Parameter 1: Line outage)	=	(50 – 31) x $51,760
	=	$983.44k

Example – Parameter 2:

Another outage example is a "B" transformer failure. In the example the following definitions are made:

- Failure Rate (λ(t)) is defined as the anticipated number of times an item will fail in a specified time period, t.
- Average Loss of Supply is annual average load on a station minus its 'N-1' capacity. Often this would be zero or less due to times of low demand.
- System Minute Thresholds for AusNet Services are 0.05 system minutes and 0.3 system minutes.
- The mean time to repair (MTTR) is the time it takes to return the failed asset to service.

Assumptions:
Failure Rate, $\lambda(t)$, in a particular year is 1%. A failure will result in a defined asset being out of service. Without this failure, AusNet Services will achieve its target performance. As a result, the 'exceeded target' column should be used. The Victorian maximum demand is 10,000 MW. Average Loss of Supply is 1 MW. The MTTR is equivalent to the transformer average of 2.6 months (or 113,880 minutes).

Parameter 2 incentive calculation:

Incentive Risk Cost (0.05)	=	If ($\lambda(t)$ x 'Average Loss of Supply' x 'MTTR' > 'System Minute Threshold' x 'Victorian Maximum Demand', '$ per incident', $0)
	=	If (1% x 1MW x 113,880 minutes > 0.05 minutes x 10,000MW, $187,500, $0)
	=	If (1,138.8 MWmins > 500 MWmins, $187,500, $0)
	=	If (TRUE, $187,500, $0)
	=	$187.5k
Incentive Risk Cost (0.3)	=	If ($\lambda(t)$ x 'Average Loss of Supply' x 'MTTR' > 'System Minute Threshold' x 'Victorian Maximum Demand', '$ per incident' , $0)
	=	If (1% x 1MW x 113,880 minutes > 0.3 minutes x 10,000MW, $187,500, $0)
	=	If (1,138.8 MWmins > 3000 MWmins, $187,500, $0)
	=	If (FALSE, $187,500, $0)
	=	$0k

Note 1: a 0.3 interruption also registers as a 0.05 interruption. Penalties are added.
Note 2: the collar should not be exceeded. This is two incidents of 0.3 system minutes and six incidents of 0.05 system minutes.

Example – Parameter 3:

Parameter 3 is the average outage duration. It is the aggregate duration in minutes of all unplanned outages with loss of supply events divided by the number of events. The historical average is 98 minutes. This is determined by taking the average outage duration from 2008-2012 and finding the average of these. It is not advised to use parameter 3 in business cases as it is dependent on the amount and length of unknown outages.

9.3.4.3. STPIS – Market Impact Component

The Market Impact Component (MIC) of the STPIS incentivises TNSPs to minimise transmission outages that can affect the economic dispatch of generation in the NEM. This is measured by the number of five minute Dispatch Intervals (DIs) where an outage on the transmission network results in a network outage constraint[24] with a marginal value greater than $10/MWh. This measure is known as the market impact parameter (MIP).

Where there is more than one network outage constraint with a marginal value greater than $10/MWh in one dispatch interval, the MIP counts the dispatch interval for each network outage constraint (that is, the same dispatch interval may be counted more than once).

Clause 4.2(a) of the current STPIS requires TNSPs to submit MIC performance data in accordance with Appendix C of the STPIS Guidelines for the preceding two calendar years. This is provided in Table 6.5 below. The target for the forthcoming regulatory control period will be determined by a rolling average of the previous three years performance. Therefore from April 2014, the target will be an average of performance in 2011, 2012 and 2013. Performance will be measured as a two year rolling average which in 2014 will be 2013 and 2014.

The maximum revenue increment that a TNSP may earn against its parameter and values under this market impact component is 2 per cent of the TNSP's maximum allowed revenue for the relevant calendar year. Assuming an approximate MAR of $500M, the maximum incentive is $10M. Assuming the three year rolling average provides a market impact parameter of 2,000 dispatch intervals, each market impact constraint dispatch interval is worth $5k. Outages on the network have been studied and the typical expected revenue reduction has been estimated[25]. These are done by asset and include three failure event types: during optimum outage conditions (M1); over a typical 24 hour period (M2); and during peak periods, overnight during independencies or other non-optimum periods (M3).

Example:

One example of an outage is the loss of an 'A' transformer at HWTS. In the example the following definitions are made:

- Failure Rate ($\lambda(t)$) is defined as the anticipated number of times an item will fail in a specified time period, t.
- The mean time to repair (MTTR) is the time it takes to return the failed asset to service.

Assumptions:

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24 Details can be found at AEMO's website www.aemo.com.au. Useful documents include:

AEMO, Constraint Naming Guidelines, Ref: SC_CM_04, Version 8, 3 May 2013

AEMO, Constraint Formulation Guidelines, Ref: 170-0040, Version 10, 6 July 2010

AEMO, Operating Procedure: Generic Constraints due to Network Limitations, Ref: SO_OP3709, Version 30, 9 November 2010

25 Andrew Maticka, Market Impact Parameter (MIP) Incentive Scheme Guide, 29 November 2012.

Failure will result in a defined asset being out of service. Failure Rate ($\lambda(t)$) in a particular year is 1%. Typical MIP $k/hr is over a typical 24hr period (M2). For an 'A' transformer at HWTS, M2 is $60/hr. MTTR is equivalent to the transformer average of 2.6 months or 1,898 hours (an 'A' transformer would usually have a longer MTTR).

Parameter 1 incentive calculation:

Incentive Reduction in Revenue Cost = $\lambda(t)$ x MTTR x M2
= 1% x 1,898hrs x $60k/hr
= $1,138.8k

Note: the maximum incentive ($10M) should not be exceeded.

9.3.4.4. STPIS – Network Capability Component

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

Participation in this component requires TNSPs to submit a Network Capability Incentive Parameter Action Plan (NCIPAP) which contains:

- A list of every transmission circuit and injection point on the network, and the reason for the limit for each.
- A list of priority projects to be undertaken during the forthcoming regulatory control period to improve the limit of the transmission circuits and injection points listed above.

AEMO plans the transmission network in Victoria. Therefore, the NCIPAP has been prepared jointly with AEMO. The incentive of this component is not for asset renewal projects, but constraint removal projects identified by AEMO.

9.4 Option and Project Selection Methodology

By aggregating all the risk costs of the assets, the baseline risk for the terminal station is valued. Generally 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 “Do Nothing” option, which is used to justify further investigation when the monetised risk is material.

The process chart in Figure 6 below shows how individual asset replacement projects are being selected 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.

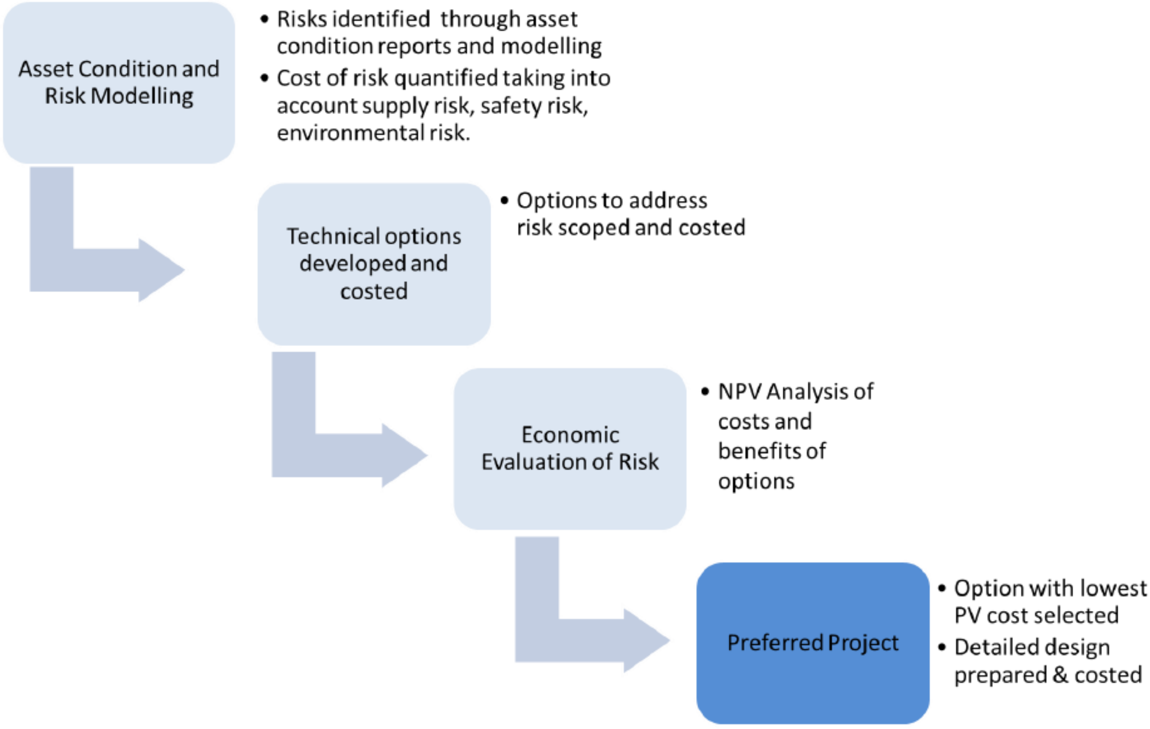


Figure 5: Project Selection Method

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 ensures 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 taken into account 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).

9.5 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 and environmental risk costs, and reducing 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.

9.5.1 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.

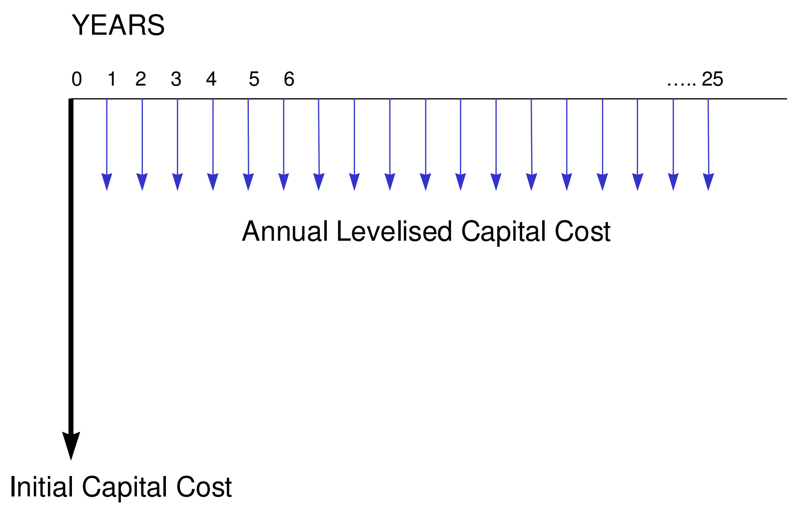


Figure 6: Illustration of the calculation of the ALCC

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.

The AER final decision regarding AusNet Services' Transmission Revenue Reset (TRR) for 2014/15 to 2016/17 allowed for a Weighted Average Cost of Capital (WACC) of 7.87% (nominal after tax). The real pre-tax WACC is calculated as 5.62% for a nominal after tax WACC rate of 7.87%.

Consistent with the AER's guideline for the Regulatory Investment Test for Transmission of June 2010, it is recommended to undertake economic analysis with a real discount rate of 7.5% for the base case and real discount rates of 6% and 9% for sensitivity studies.

9.5.2 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.

9.5.3 Sensitivity Studies

Sensitivity studies around the discount rate, VCR rate, asset failure rate and demand growth scenarios are conducted to test the robustness of the economic evaluation. The sensitivity studies are used to test the robustness of the selected option and the proposed economic timing for the preferred option to proceed for changes in the input assumptions. This is a crucial step in ensuring replacement investment is economic under a range of reasonable scenarios[26].

26 The Transmission Planning Assumptions are detailed in Appendix A

9.6 Preferred Option

A detailed project scope and cost estimate is prepared for the most economic. 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 timing 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) and the Distribution Businesses (Transmission Connection Planning Report). It is also consistent with the principles underpinning the regulatory investment test for transmission (RIT-T).

10 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.

10.1 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.

10.1.1 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.
- Emergency rating. In some cases an emergency 2 hour rating will be noted and this will often bring the transformer to a higher winding temperature of typically 140 degrees Celsius.
- 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.

10.2 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.

11 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 and the distribution businesses respectively to ensure individual decisions will not impede efficient future augmentation or compromise security of supply. Consultations with AEMO 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 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 (taking into account the total project capital cost, operating and maintenance cost and expected risk costs) for all credible options is calculated. A real discount rate consistent with AusNet Services' weighted average cost of capital (WACC) is applied in the analysis. 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.

- 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, and value of customer reliability.

- Scope of Work - Provide a summary of the high level scope of work for the preferred solution.

12 Program/Project Life Cycle

The Business Case Development Guide (AMS 02-02, available in ECM) provides a detailed description of the process that needs to be followed to seek approval for a new project or to revise an existing business case. It steps through the key stages of the project life cycle, including Idea, Plan, Build and Close.

To formally raise a project, access to SAP – PPM module is required. This can be secured by raising a request (Service Portal on Intranet).

To activate a project, it must be selected into the pipeline of active projects at Gate 2. Once a project is selected into the pipeline, the business case development process automatically starts. The Business Case Development Guide[27] provides more detailed Asset Management requirements for each step of the business case development process.

Once a project business case is approved (at Gate 3), the project is formally released to Service Delivery for design, construction and close-out.

As Asset Owner, project Initiators are required to endorse project close-out in the business transition process.

The Program/Project life cycle is illustrated in Figure 7 below.

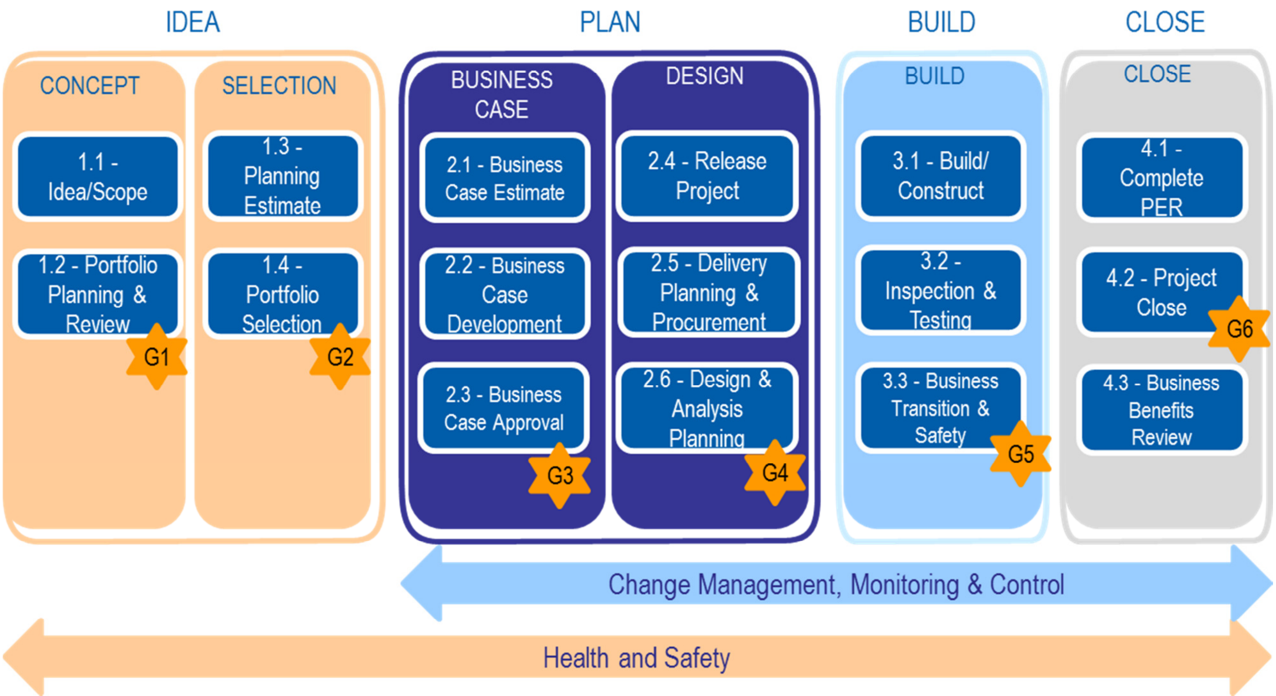


Figure 7: Program/Project Life Cycle

27 AMS 02-02 Business Case Development Guide

13 Abbreviations

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

14 Appendix A: Transmission Network Planning Assumptions

Parameter	Value
Discount Rate	Real discount rate of 7.5% and sensitivity studies with 6% and 9%.
Load profiles to use for supply risk assessments: Summer POE10 and POE 50 Winter POE10 and POE50	Summer Period is defined from 1 October to 31 March and Winter Period is defined from 1 April to 30 September. Summer POE50 Profile: Summer 2012/13 profile Summer POE10 Profile: Summer 2013/14 profile Winter POE10 and POE50: Winter 2013 profile
POE10 and POE50 Weighting	30% of POE10 EUE and 70% of POE50 EUE
Formula for probability of asset being out of service.	P(down) = MTTR/(MTTF+MTTR) = $\lambda/(r+\lambda)$. Failure rates as per Risk Models
Transformer MTTR	**B Transformers** : MTTR = 2.6 months, reflecting that it is a major transformer failure that would require off site repairs, but that the metro or country spare transformers could be used when available to cover this risk. MTTR for the second and third transformer outages = 2.6 months. **A, H and M Transformers:** MTTR when a spare is available = 1 to 2 months. MTTR when no spare is available = 18 to 24 months. (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)
Circuit Breaker MTTR	220kV CB Major Outage MTTR: 168 hrs 66kV CB Major Outage MTTR: 96 hrs (SPIE example) Minor Outage (isolate CB) MTTR: 2 hrs Consider multiplying the CB failure rate with a 1.3 factor to reflect that a circuit outage can be caused by other systems and plant (protection, CT, isolators, etc.).
Community Impact for 66 kV network (CB outage)	A major failure of a bus tie CB 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. Use methodology shown in Appendix B
VCR	Use latest TCPR VCR Rates for each terminal station

<table>
<tr><th>Parameter</th><th>Value</th></tr>
<tr><td>Market Benefits</td><td>AEMO's market impact / benefits study results</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>Expected Unserved Energy (EUE). Energy at Risk (EAR)</td><td>EUE = EAR x P(down state)</td></tr>
<tr><td>Health and Safety Risk</td><td>Plant explosive failure consequence $[C-I-C]. Health and Safety Risk for economic evaluation = P(explosive failure) x P(plant major failure) x $[C-I-C]. Safety risk should be based on the total risk for the old plant and not the incremental risk reduction as new technology switchgear does not exhibit explosive failure characteristic.

<u>CTs</u>
Major failure rate as per CT Risk Model x Probability of explosive failure (0.15 to 0.05 for 220kV CTs and 0.1 to 0.05 for 66kV CTs).

<u>ASEA Transformers and transformers with oil impregnated paper bushings</u>
Transformer Risk Model failure rate x Probability of explosive failure (5%)

<u>LG4C CBs</u>
Major failure rate as per CB Risk Model x Probability of explosive failure (0.05).

<u>HKEYC 66 kV CBs</u>

Major failure rate as per CB Risk Model x Probability of explosive failure (0.05).

(Apply the same methodology for other type of CBs if they also pose an explosive failure risk, i.e. major failure rate as per CB Risk Model x Probability of explosive failure (0.05))</td></tr>
<tr><td>Plant Collateral Damage Risk</td><td>Average of $1 000 K per event. Major failure rate as per Risk Model x Probability of an explosive failure (10%) x factor that reflects the proximity and likelihood that adjacent plant may be damaged. The factor should be between 1 and 0 and will be site and location specific.</td></tr>
</table>

Parameter	Value
Environmental Risk	LG4C CBs or plant that contains large volumes of oil and which could pose an environmental risk = $30K. $100K for transformers with PCB in oil Major failure rate as per CB Risk Model x Probability of environmental impact (5%).
Network Losses and Carbon Cost	Ignore unless significant
O&M Cost	220 kV CB: old = $1 850 pa; New = $550 pa 66 kV CB: Old = $800 pa; New = $340 pa 22 kV CB: Old = $435 pa; New = $90 pa 220/66 kV Transformer: Old = $2 175 pa; New = $375 pa Use the incremental benefits in the economic evaluation, i.e. old O&M cost – new O&M cost. Assume a 3% pa escalation in O&M cost
Emergency CB and Transformer Replacements for the “Replace on Failure” Option	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% - 30%. Also the country and metro spare transformers are “special” transformers to allow for their deployment at any site. This can be accounted for by allowing an additional $0.5 M 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.

15 Appendix B: Transmission Connection Network Economic Evaluation

Calculation of expected unserved energy benefits associated with replacement of 66kV circuit breakers at terminal stations:-

1. Transformer 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 * 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 * 96/8760 * 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 * 96/8760 * 1000 = 0.01).

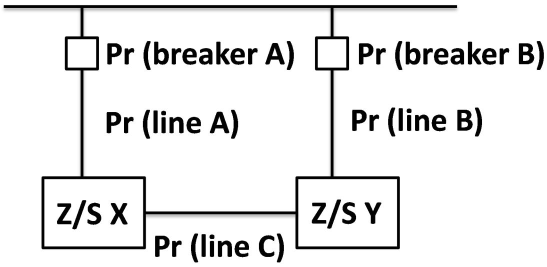
The net benefit is 0.54 MWh. This can be valued at VCR for that station.

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)) * (Pr (circuit breaker B) + Pr (line B)) * Annual loop energy + (Pr (circuit breaker A) + Pr (line A)) * Pr (line C) * annual Z/S X energy + (Pr (circuit breaker B) + Pr (line B)) * Pr (line C) * 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 & 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) * (0.06 X 96/8760 + 2/8760) * 60 * 8760 = 0.000557 * 0.000886 * 60 * 8760 = 0.259 MWh

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

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

Total Expected Unserved Energy = 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.

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 * 2hours/8760hours * 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 * 2/8760 * 150 MW * 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 * 2/8760 * 60 MW * 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.