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Industry practice application note

Asset replacement planning

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1 Overview

1.1 Purpose and objectives

The National Electricity Rules (NER) require Network Service Providers (NSP) to disclose information in their Annual Planning Reports (APRs) and Regulatory Investment Tests (RIT) relating to network asset retirement, renewal (that is, replacement or refurbishment), and de-rating. These requirements follow the Australian Energy Market Commission's (AEMC's) recent rule determination on changes proposed by the AER.[1]

We have developed this Application Note in response to NSP requests for clarity on how to apply the NER to replacement expenditure planning for network assets. In particular, we have been requested to clarify how NSPs can meet the NER requirements to demonstrate the prudency and efficiency of network asset investment on asset retirement and de-rating decisions.

We publish guidelines from time to time to assist NSPs in applying the NER to the aforementioned topics. This Application Note does not replace published guidelines. Rather, it supplements the guidelines by outlining principles and approaches that accord with good asset management and risk management practices.[2] The principles and approaches therein support sound asset retirement and de-rating decisions and subsequent capital or operating expenditure commitments (if any) within the context of the NER requirements and good electricity industry practice.[3]

In preparing this Application Note, we have sought to strike an appropriate balance between outlining the relevant principles to enable a consistent understanding and use of effective technical and economic practices amongst NSPs and specific methods or practices that can be applied by NSPs. We outline a framework with reference to a range of practices. In doing this, we preserve and promote the ability of NSPs to develop and continue to refine asset management and risk assessment practices, within the context of the NER's economic framework, that are appropriate to each NSP's circumstances.

We intend for this Application Note to continue developing as industry practices evolve, in Australia and internationally.

Reference to the NER and specific clauses is made with reference to the published version of the NER at the time of publication. As such this Application Note may not include changes related to replacement planning made since that time.

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1 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

2 Good asset management and risk management practices are often aligned with international standards of practice, such as ISO 55000 for asset management and ISO 31000 for risk management.

3 As defined in the NER.

1.2 Background

1.2.1 Rule change request

In response to our assessments of NSP capital expenditure (capex) proposals, and reviews of APRs, we submitted a rule change request to increase the transparency of planning decisions surrounding network asset replacement and de-rating. We proposed the rule change in the context of a changing electricity environment. Specifically, we observed that:[4]

> *there have been significant changes in the national electricity market and the broader energy industry that have spurred on a change in network planning and investment patterns, making replacement expenditure of greater relative importance than augmentation expenditure;*
>
> *technological changes have emerged such that non-network solutions are becoming more viable alternatives to replacement network investment; and*
>
> *there is now a greater focus on managing existing network assets in comparison to the historical focus on expanding networks due to the flattening of electricity demand growth.*

1.2.2 Final decision on rule change

The AEMC amended the NER to include requirements for replacement expenditure planning.[5] These amendments aim to increase the transparency of NSP plans for retiring or de-rating network assets.

Generally, the NER aligns the information reporting requirements for replacement projects with those that already exist for augmentation projects, and APRs must consider all capex investment needs regardless of the driver. Accordingly, APRs must report on network asset retirements and de-ratings that lead to network limitations or constraints and which may drive subsequent capex.

APRs must report the same information for augmentation and replacement investments, and must identify:

- all planned network asset retirements over the forward planning period (a minimum of five years for distribution networks and ten years for transmission networks);
- all planned asset de-ratings which result in a network constraint or system limitation over the forward planning period;
- a description of the asset and its location;

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4 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. i.

5 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. ii.

- the reasons, including methodologies and assumptions used for deciding that it is prudent for the network asset to be retired or de-rated, taking into account factors such as the condition of the asset;
- the date from which the asset will be retired or de-rated and, if this has changed from the previous APR, an explanation of why; and
- information on the asset management practices used, including the asset management strategy employed.

Provisions also exist for reporting retirement and de-rating information for multiple assets.[6] Reporting should be on an asset basis and not on a project basis or on an asset component or part basis.

NER Chapters 6 and 6A describe the procedures governing the economic regulation of networks, and the obligations of NSPs in preparing revenue proposals. Including asset retirement and de-rating decisions in APRs, and consulting with stakeholders earlier as defined in Chapter 5 should promote more efficient regulatory processes for reviews under NER Chapters 6 and 6A. Whilst obligations under Chapter 5 (Part D) are distinct from those under Chapters 6 and 6A, if NSPs justify their expenditure decisions under Chapter 5, by implication, they are more likely to meet their obligations under Chapters 6 and 6A.

Accordingly, NSPs should develop their asset management and risk management processes to undertake risk assessments as part of their APRs. Doing this will support their revenue proposals and assist in our reviews.

1.2.3 Changing operating environment

The environment in which NSPs now operate is significantly different since the introduction of the transmission and distribution network planning frameworks. As a result, changes to the planning framework are required to continue to promote efficient network development.

In its final decision, the AEMC acknowledged three key points:

- electricity demand growth has flattened across much of the NEM;
- in the current and expected environment, replacement capital expenditure has been a growing proportion of total capital expenditure; and
- technological changes are challenging the previous presumption of like-for-like replacement.

The combination of potentially credible alternative technologies and low (and uncertain) demand growth means that long term investments in network infrastructure with a 40 or 50 year plus technical life has heightened investment risk. Stranded or under-utilised network assets represent poor economic outcomes for utilities and consumers that are less likely to be reversed through natural growth than was previously the case. Any decision to retire an asset and replace it (typically the most capital-intensive approach) must therefore carefully

6 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. ii.

consider the long-term uncertainty in the demand for the service provided by network assets, and the increasing potential for credible alternatives to provide equivalent services.

1.3 Structure of this document

Section 2 describes principles relevant to understanding and applying this Application Note, and for meeting the replacement expenditure planning requirements of the NER.

The following sections describe how to address two related but separate decisions to:

- retire or de-rate an asset (Section 3); and
- invest or commit to an ongoing operational action after making an asset retirement or de-rating decision where a network or service constraint is exists (Section 4).

The decision to retire or de-rate an asset may not always create a subsequent investment or ongoing committed cost. However, typically, where retiring or de-rating an asset causes a service constraint, some form of network or non-network investment or operational action may be required.

It is important to at least conceptually separate these two decisions to ensure all options to maintain the service level are explored. Doing so will help achieve the most efficient long run service cost consistent with the National Electricity Objective (NEO).

Section 5 provides a methodology to estimate the expected total service cost.

Additional appendices compare a sample of approaches, input assumptions and provide examples.

1.4 Definitions

Table 1 sets out definitions that apply in this Application Note:

Table 1: Definitions

Term	Definition
asset risk-cost	the monetised total cost of risk developed on a per-year basis. Essentially, this is the expected total cost incurred as a consequence of the service level not being maintained due to the performance of the asset.[7]
annualised capital cost	the uniform capital cost of a project or program of work, expressed as an annual equivalent amount (taking account of a reasonable discount rate), used for comparative analysis.
asset de-rating	in respect of an NSP, the reduction in the service capability of a network element.

7 This may have many dimensions: for example, safety-related risk-cost through increased safety risk, reliability risk-cost through increasing probability of asset failure (where this leads to, or may lead to, supply failure, or safety consequences); also, risk-costs related to increasing environmental risk or bushfire-related risks.

asset failure	when asset can no longer perform its intended function. The asset may still be operating but may not be capable of delivering all of its required functionality. The asset may or may not be repairable.
asset maintenance	‘business as usual’ or routine preventative (e.g. inspection and testing) and corrective (e.g. minor repairs) activities to sustain the asset’s functionality and keep it in service to achieve its expected technical life.
asset refurbishment	expenditure to extend the engineering life expectancy of an asset (but not increase its functionality) by replacing or repairing parts of an asset rather than the whole. These activities are generally capex as they extend the productive life of an asset, but could also be opex depending on the work performed and relevant accounting practices
asset renewal	asset refurbishment or replacement.
asset replacement	an option that involves replacing an asset for which a retirement decision has previously been made. This will involve installing a new network asset with the modern equivalent and similar functionality to the asset being retired.
asset retirement	removing an asset or part of a fleet of assets from service.
cost threshold	the cost threshold specified in NER clause 5.15.3(b) or 5.15.3(d) (as relevant).
capacity stranding	a condition where the value of an asset(s) is diminished due to the expectation that the capacity of the asset(s) will be partially or fully underutilised for the remainder of its technical life.
capacity stranding cost	the cost (or expected cost) of an asset(s) diminished value that arises from capacity stranding.
credible option	has the meaning given to it in NER clause 5.15.2(a).
distribution asset	the apparatus, equipment and plant, including distribution lines, substations and sub-transmission lines, of a distribution system.
economic life	when the total cost of providing the required service from the asset no longer represents the lowest long run cost to consumers of providing that service (i.e. after considering alternatives).
electrically adjacent network elements	elements of the network that contribute, or can contribute, to the supply of electrical power (i.e. power flow) to the load and/or from the generation source(s) that is normally provided by the asset being assessed for retirement or de-rating. This may or may not require switching of one or more network elements.
firm delivery capacity	the maximum allowable output or load of a network or facility under contingency conditions, including any short-term overload capacity having regard to factors that may affect the capacity of the network or facility.
forward planning period	the period determined by a DNSP under NER clause 5.13.1(a)(1).

	A period of at least 10 years for TNSPs as per NER 5.12.1(c).
good electricity industry practice	has the meaning given to it in NER Chapter 10.
identified need	the objective an NSP (or in the case of a need identified through joint planning under NER clause 5.14.1(d)(3) or clause 5.14.2(a), a group of NSPs) seeks to achieve by investing in the network. Reference should also be made to the AER's Regulatory Investment Test guidelines.
load transfer capacity	the capacity in all electrically adjacent network elements that may be available at each point in time to at least partially offload (de-load) the asset (or assets) being assessed for retirement or de-rating.
market benefit	has the meaning outlined in paragraph 4 of the RIT-T and RIT-D guidelines, for transmission and distribution, respectively.
non-network provider	a party who provides non-network options.
normal cyclic rating	the normal level of allowable loading on a facility, item of plant or network element having regard to external factors that may affect the rating, such as ambient temperature, wind speed, load cycle, etc..
O&M	the routine operational and maintenance activities associated with asset management
operational control	an operating measure intended to modify, or mitigate, risk (e.g. operational procedures)
potential credible option	an option which a RIT-D or RIT-T proponent (as the case may be) reasonably considers has the potential to be a credible option based on the proponent's initial assessment of the identified need
reconfiguration investment	has the meaning given to it in NER clause 5.16.3(a)(5)
reliability corrective action	has the meaning given to it in NER clause 5.10.2
risk cost	the quantified cost (typically expressed in dollars) of a particular risk or set of risks, accounted for on a probabilistic basis
service cost	the aggregate of 'business as usual' operations and maintenance cost (e.g. corrective and preventative maintenance) and the risk cost associated with a particular service
service level	the defined *service* quality for a particular activity or service parameter, against which performance may be measured. This typically encompasses safety, reliability, quality of supply, environmental and compliance parameters
service risk	the risk posed by an asset failing to meet the prescribed service level. The risk cost may include the quantification of the service risk
system limitation	a limitation identified by a DNSP under clause 5.13.1(d)(2).

system limitation template	a template developed and published by the AER under clause 5.13.3(a).
technical life	the typical expected life of an asset before it fails in service under normal operating conditions. The technical life may differ between businesses (due to different operation environment factors) and between asset classes. This should be referenced to typical industry values.
technical obsolescence	the asset technology is no longer capable of fulfilling its function (e.g. due to lack of support, or inadequate design, etc).

2 Principles

This section covers principles relevant to understanding and applying the practices addressed in this Application Note and in complying with the requirements of the NER for replacement expenditure planning. These principles are:[8]

1. alignment with the National Electricity Objective (NEO), the NER, and good industry practice;
2. service requirements vary over time and cannot be known with certainty;
3. the asset's service cost varies over time;
4. technical end-of-life is a trigger for assessing the prudent response;
5. economic end-of-life should be demonstrated for asset retirement;
6. the need to de-rate an asset may arise from technical and economic sources;
7. options analysis should be comprehensive and robust; and
8. flexibility, small scale actions, and deferral have economic 'option' value (see section 4.4.3 for a discussion on option value).

Principle 1. Alignment with the NEO, the NER, and good industry practice

To align with the NEO and to satisfy the requirements of the NER, asset management practices should enable demonstrably prudent and efficient expenditure decisions that accord with good electricity industry practice. This should, among other things, provide transparency of key information so key stakeholders are sufficiently informed about NSP's planning and decision making processes. These key stakeholders include, but are not limited to, non-network service providers, users of the network, and the AER.[9]

We have sought to align this Application Note with the precepts in the ISO55000 (asset management) and ISO 31000 (risk management) document sets, including reference to data driven and evidence-based approaches that employ quantified variables and parameters. Other international frameworks, such as the IEC 60300 suite, may also provide valuable sources of relevant good industry practices.

Principle 2. Service requirements vary over time and cannot be known with certainty

The service levels an asset must provide are typically defined in terms of supply reliability, safety, environmental impacts, etc.. Service level requirements may change due to external factors such as changing stakeholder preferences, which may be reflected in the NER and/or other legislative instruments.

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8 Australian Energy Market Commission*, Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017.

9 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. i.

The advent of distributed generation, intermittent asynchronous generation, and energy storage options (among other things) are fundamentally impacting on service requirements and hence the functionality expected of network assets. These changes will undoubtedly continue, although the opportunities they present and their impact on existing network assets cannot be predicted with anything close to certainty at this time.

Retirement and de-rating decisions, and decisions about the least-cost approach to providing the level of any subsequent ongoing service, must consider the likelihood of change and the challenges in predicting the nature and extent of those changes.

Principle 3. The asset's service cost varies over time

The asset's service cost (or total cost of service) includes all costs that the consumer ultimately incurs to maintain the service level over time. It is derived from the sum of ongoing costs, including the cost of risk. The asset service cost will typically increase over time if there is no intervention, particularly where an asset's condition follows a wear-out characteristic. For example, the costs associated with an asset failing in service such as unserved energy costs, repair costs, the cost of losses due to fire or incidents of a safety or environmental nature will typically increase as the probability of the asset failure increases. All such relevant costs should be considered when demonstrating prudent and efficient asset management decisions including asset retirement decisions.

Principle 4. Technical end-of-life is a trigger for assessing the prudent response

An asset is at the end of its technical life when its assessed condition suggests a reduction in its ongoing ability to maintain the required service levels, and intervention beyond 'business as usual' operational maintenance is indicated.

A change (or expected change) to the operating environment may also trigger reconsideration of the asset's technical capability to meet expected service level requirements. Whilst otherwise functional, the change in the operating environment may result in the asset no longer being fit for future purpose despite being functional for meeting current service level requirements.

Where the asset's condition suggests it is approaching the end of its technical life, this should trigger an assessment of the prudent response which may include life extension, acceptance of the service risk, non-network options, asset retirement or de-rating.10

Principle 5. Economic end-of-life must be demonstrated for asset retirement

The end of economic life of an asset is reached when the total cost of providing the service provided by the asset no longer represents the lowest long run cost to consumers, considering alternatives.

An important trigger for assessing whether an asset is at the end of its economic life is an assessment that the asset is at or near the end of its technical life. However, asset

10 Cases may also exist where an asset is assessed to have no enduring purpose because of changes to the operating environment and required service levels such that the asset is rendered obsolete.

retirement may be triggered by economically preferable alternatives to retaining the current asset in service. New or emerging technologies and innovative alternatives may render it economically preferable to retire an existing asset before its technical end-of-life or before a more traditional assessment would have deemed the asset to be at economic end-of-life.

A decision to retire or de-rate an asset (or part of an asset fleet) creates options for how to meet any existing or future service demands associated with that asset post its retirement or de-rating. An efficient asset retirement or de-rating decision will minimise the expected total cost of providing the service to the consumer at the required service levels. Consequently, a retirement or de-rating decision must have regard to the relative service costs expected if the asset is not retired or de-rated. This decision should also consider the service costs expected if the service level is met from implementing an alternative option. These concepts underpin the definition of the counterfactual and factual scenarios in the relevant decision analysis.

Factors such as the ongoing demand for the service, the service levels required, the asset's condition, and the state of the operating environment are variable and may be uncertain across the service life. Accordingly, for an economic analysis to reasonably arrive at a demonstrably efficient retirement or de-rating decision, it must consider and account for uncertainty and for the value of deferral and optionality (see Principle 8).

Principle 6. The need to de-rate an asset may arise from technical and economic sources

De-rating an asset means that it is assigned a lower capability to function than its original or initial capability that is typically measured in terms of its continuous operating rating.[11] The decision to de-rate or lower the assessed functional capability of an asset is typically a technical decision. However, it is also an economic decision as de-rating may result in a network constraint at some time in the foreseeable future, or may take into account the likely increase in an asset's service cost (i.e. where the asset is de-rated to reduce the likely increase in the service cost). Hence a de-rating decision that leads to a network constraint or a change in service costs should be based in economic analysis that determines the lowest long run cost to consumer.

[11] The continuous rating is determined by considering typical operating parameters (e.g. temperature range) and it represents loss of life equivalent to one year of the asset class' technical life for each year of operation (i.e. no accelerated aging).

BOX 1 – Asset de-rating as a response to increasing cost of service

An asset manager's assessment that an asset's expected service cost will increase if business-as-usual practices are maintained, *may* lead to the decision to de-rate the asset.

For example: condition data for a cable shows that the cable's insulation is degrading. The probability of failure of the cable is increasing (failure is more likely, or the service life is reduced) and hence the asset's expected service cost is increasing. Possible management actions would include running the cable to failure (i.e. accept the increased service cost), replace the cable like-for-like when the asset's expected service cost equals the replacement cost, or de-rating the cable now and hence reduce the asset's expected service cost by reducing the in-service failure probability. Other benefits would then include the real option value associated with future alternatives that may better fit the service needs at that time. So, in the case of de-rating, the point at which management action is indicated depends upon the same considerations as an asset retirement decision but can be considered in the framework of the options available to address the likely increase in the asset's service cost.

Principle 7. Options analysis should be comprehensive and robust

Deciding whether to retire or de-rate an asset (as the prudent first step) requires considering credible options (including risk treatments) to meet any ongoing or future service level requirements[12] arising from the retirement or de-rating decision. An essential requirement of NER Chapter 5 is that the options analysis is comprehensive and robust and provides evidence that retiring or de-rating[13] the asset is part of an overall solution that represents the maximum long run net benefit across the NEM.

Principle 8. Flexibility, small scale actions, and deferral have economic 'option' value

As discussed above, the future operational environment is characterised by uncertainty. Greater levels of uncertainty require a greater focus on preserving optionality as some uncertainties may resolve over time, and with more time, a greater range of options may become available.

Small scale actions taken now, or deferral, provide option value by reducing the potential for future regret from locking into a large-scale investment that later turns out not to have been needed or not well suited to future service level needs. The greater economic value to consumers that is realised through optionality should be recognised in comprehensive and robust options analysis.

12 Even if an asset is being retired and no further options to meet service levels are being proposed, there may be necessary in consider some form of risk treatment in addition to or instead of routine operations and maintenance activity.

13 In addition to the need to de-rate an asset due to its inability to provide the design capacity, asset de-rating can be considered as a life extension option.

In addition, options such as risk avoidance, risk reduction, and risk sharing are particularly attractive shorter-term mitigation strategies in response to technical end-of-life challenges, and further preserve the flexibility for better-informed investment in the face of uncertainty.

BOX 2 – Importance of holistic review of credible options

In our proposal to the AEMC to introduce replacement expenditure reporting and planning arrangements to the Chapter 5 planning framework we emphasised the need to ensure that the Chapter 5 framework adapts to the changing network environment – particularly the uncertainty in which networks will evolve – and continues to promote efficient network investment.

The proposed amendments will ensure that:

- *there is a consistent, clear, transparent and timely planning process for network replacement decisions*
- *there is an adequate consideration of alternative investment options, including non-network options, and like-for-like replacement*
- *network users have an understanding of changes to the network as a result of network replacement decisions and how this may affect connection plans*
- *there is greater transparency to both policymakers and the AER on network replacement expenditure*

Source: Australian Energy Regulator, RC0209-Replacement-Expenditure-Panning-Arrangements-Rule-change-request, June 2016, pages 12-13

Furthermore, we sought to extend the existing and familiar reporting arrangements that already existed for augmentation projects to replacement projects to promote a more expansive list of credible options.

The proposed amendments seek to require network businesses to report in the APR on forecast network limitations which are expected to arise as a result of planned retirement and de-rating decisions and provide information on proposed options to address these limitations. This would flag potential investment opportunities in the network for non-network proponents and other stakeholders. Third party proposals could then assist NSPs in determining viable options and help prepare for future RIT consultation processes. Additionally, focusing on network limitations rather than individual assets ensures that network projects are considered holistically, rather than artificially divided into smaller projects. Lastly, this information would also make connection applicants aware of changes to the network which may impact locational decisions.

Source: Australian Energy Regulator, RC0209-Replacement-Expenditure-Panning-Arrangements-Rule-change-request, June 2016, pages 15

3 Making an asset retirement or de-rating decision

This section sets out an approach and supporting process for identifying the need to retire or de-rate an asset (or fleet of assets) because the asset's condition suggests it is may be at or near the point where it is no longer capable of efficiently providing the required level of service. This would be reflected as an expectation of increasing service cost.[14]The subsequent section (section 4) describes the identification and analysis of options to respond to the identified need to retire or de-rate the asset(s). The option (or combination of options) is selected which provides the least cost approach to satisfy the required service level. That is, provides the required service level at the minimum service cost.

3.1 Summary of current issues

Through our assessments of NSP capex proposals, and our review of APRs, we have observed several issues surrounding the treatment of network asset retirement and de-rating decisions. The amended requirements in the NER, when considered along with the RIT application guidelines are intended to provide greater clarity to NSPs, and help improve the transparency and consistency of capex proposals.

The issues we observe, which are likely to lead to capital and operating expenditure inefficiencies include:

- inadequate analysis of possible and imminent changes to the operating environment and how they may present opportunities and risks to identifying the best treatment for a particular asset;
- failure to define the identified need in terms of the objective the NSP seeks to achieve by investing in the network, and particularly in terms of the capital expenditure objectives and the NEO;
- inadequate identification of potential credible options, including life extension options, but particularly non-network solutions, to treat the risks and opportunities inherent in the identified need;
- failure to clearly define and reasonably assess a credible counterfactual based on and relevant to the identified need;
- poor specification of credible options relative to the counterfactual; and
- failure to select the option or combination of options that represent the lowest service cost in the long run, including by demonstrating that the timing of retirement and the subsequent investment (capex and/or opex) is prudent and efficient.

The decision-making process followed by many NSPs has traditionally been asset centric, with an orientation towards asset replacement. This contrasts to processes centred around service levels with an orientation to the lowest long run cost to meet the required service levels.

14 As we described in the previous section, this may be due to the assets condition, but may also be due to changes to the required service level or to the availability of alternative options that were not previously available or economic.

Long run costs are estimates made in the context of uncertainty about key factors such as actual asset life, demand characteristics and technology. Prudent investment decisions therefore need to consider option value as means of enabling investment paths of 'least regret' to be taken, including:

- scenario analysis – considering several possible futures, to help identify options and maintain option availability before committing to major capex; and
- the value of small scale actions and deferral – to help minimise capex commitments to assets or groups of assets with high capital cost and very long lives, which can provide flexibility for as long as it is prudent to do so.

When looking from a consumer perspective, the objective for NSPs is one of maintaining service levels, whilst providing the service at an efficient cost. This may require a range of options that continue or extend the operating life of an asset, substitute non-network options for the service provided by the asset (in whole or in part) or, as a final option, replacing the asset to maintain the required service level.

BOX 3 – Maintaining service levels

As nominated in NER 6.5.7 the capital expenditure objectives require that the service levels are maintained.

(a) A building block proposal must include the total forecast capital expenditure for the relevant regulatory control period which the Distribution Network Service Provider considers is required in order to achieve each of the following (the capital expenditure objectives):

(1) meet or manage the expected demand for standard control services over that period;

(2) comply with all applicable regulatory obligations or requirements associated with the provision of standard control services;

(3) to the extent that there is no applicable regulatory obligation or requirement in relation to:

(i) the quality, reliability or security of supply of standard control services; or

(ii) the reliability or security of the distribution system through the supply of standard control services,

to the relevant extent:

(iii) maintain the quality, reliability and security of supply of standard control services; and

(iv) maintain the reliability and security of the distribution system through the supply of standard control services; and

(4) maintain the safety of the distribution system through the supply of standard control services.

Source: National Electricity Rules v111

3.2 Good electricity industry practice

The state of electricity network assets varies across Australia. A range of variables including past purchasing decisions, local environment factors and operating practices vary across NSPs as ownership, investment levels and service level outcomes have changed over time.

This presents each NSP with a set of challenges to manage its fleet of assets with reference to good electricity industry practice.

Amidst these challenges, there has been variation in how each NSP manages its asset fleet. Increasingly, NSPs are claiming alignment with international standards and/or seeking certification provided by an independent verifier. While this has assisted in moving the industry towards common standards, the international standards themselves set out principles and provide guidance, but do not specify particular practices specific to good industry practice in the electricity supply industry. However, under the regulatory framework, and through the regulatory review process, publication of RIT guidelines, APRs, and RITs, a greater definition is emerging of good electricity industry practice surrounding asset replacement planning decisions. International standards will however continue to provide a key reference for good practice asset management and risk management (amongst other things).

Importantly, in making the replacement planning rule change, the AEMC saw the APRs and RITs as having an important role in supporting network planning and investment decisions by:

- creating incentives for NSPs to consider potential non-network solutions to network constraints or limitations;
- establishing clearly defined planning and decision-making processes to assist NSPs in identifying the solutions to network issues in a timely manner; and
- providing transparency on network planning activities to enable stakeholder engagement with those activities to support efficient investment in the network.[15]

The AEMC's final decision stated that the purpose of the planning framework is not to regulate or to direct which plans or decisions should be made, nor to determine what investment costs should be recoverable from regulated prices and revenues. However, the planning and investment framework operates within an incentive-based economic regulatory framework that advances the NEO.

The NER does not require the NSP to adopt or apply a specific planning framework, nor does it specifically require compliance with international standards. Rather the onus is on each NSP to demonstrate it has made prudent and efficient decisions to ensure it meets the required service level outcomes and to provide evidence of the efficient level of expenditure required to achieve the capital expenditure objectives. In doing so, it should make reference to good electricity industry practice.

3.3 Identification of the need

For an NSP to invest in the network, it must confirm the objective it seeks to achieve – this is the 'identified need' defined in clause 5.10.2 of the NER. For asset renewal, the identified need would typically consist of meeting the NSP's defined service levels. These service levels would be linked to the capital expenditure objective, the technical requirements of

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15 Australian Energy Market Commission, *Rule Determination, National Electricity Amendment (Replacement expenditure planning arrangements) Rule 2017*, 18 July 2017, p. i.

schedule 5.1 of the NER, to jurisdictional instruments, to considerations such as consumer expectations.

The description of the identified need generally comprises two parts:

- definition of the service level, and
- assessing the capability to meet service level requirements.

These are discussed in the following sections.

An identified need may also involve an increase in consumer and producer surplus, although this is more often associated with network augmentation or extension than with asset retirement planning.

3.3.1 Defining the service level

NSPs establish the specific measurable parameters underpinning the service levels provided by its assets. NSPs establish this with regards to consumer preferences and regulatory/compliance obligations within the context of the relevant NER requirements. Whilst the definition of specific service levels may change across jurisdictions, the nature of the assessment should be similar across NSPs.

Consumer service preferences, regulatory and other legislative obligations are relatively stable in the electricity industry compared with other industries. However these can, and have changed with significant impacts on NSP's business models, expenditure forecasts, and activities.

Compliance obligations may not be hard obligations, but recognise a best endeavours approach (for example, exceeding voltage standards). Service levels should recognise the varying nature of network services and allow for reasonable variation to maintain efficient service costs outcomes.

Typically, organisations will seek to define acceptable minimum service levels, with the incentive to economically outperform the cost of providing them inherent in the NER. NSPs develop these service levels cognisant of their business strategy, investment planning framework and asset management strategy (amongst other things). Consequently there should be a clear linkage between the NSP's strategies employed in managing its assets and the service levels delivered by those assets. Accordingly, there should be a clear linkage between the investment decisions of the NSP and the impact on service level outcomes.

3.3.2 Assessing the capability to meet service level requirements

The investment need is typically based on an assessment of the asset's ability or inability to continue to meet or contribute to meeting required service levels, having determined the service level requirements.

Actual or potential issues with the capability of an asset to efficiently meet the service level requirements may be identified through one or more of the following:

- changes in the operating environment, including changes to one or more of: electricity demand (level, location, and other characteristics), generation (levels, location, and other characteristics), regulations, or standards;
- understanding the modes and rates of deterioration of assets through methods such as Failure Modes Effects Analysis (FMEA);
- assessing the asset's condition, and the ability of the asset to deliver its design functions, which is usually determined from a combination of sources, such as: inspection and test result trends, historical defect trends, and asset performance trends (e.g. outage duration and frequency and failure trends);
- changes in consumer preferences or requirements, including system performance trends (e.g. impacts on service level standards, including reliability, environmental compliance, and safety); or
- information about the service level performance of a particular asset type from industry-wide experience.

Establishing that there is a case to retire or de-rate an asset, or portion of an asset fleet, requires the NSP to provide evidence to support its conclusion about the asset's capability to provide the required service levels at an efficient cost.

If the assessment is applied to an asset 'fleet', or portion of an asset fleet, then there should be sufficient evidence that it is applicable to the fleet and is sufficient to reflect the performance of the fleet rather than behaviour of an individual asset.

BOX 4 – Understanding service levels

Industry practice includes reference to, or alignment with, contemporary asset management standards such as ISO 55000. The degree of alignment will vary by business and is often linked to obligations set out in jurisdictional planning standards, and/or licence conditions.

For example, the ISO 5000 suite of standards is predicated on realising value from assets. This balances financial, environmental, and social costs, with risk, quality of service and performance of the related assets.

In ISO 55000, the level of service is defined as

> *Parameters, or combination of parameters, which reflect social, political, environmental and economic outcomes that the organisation delivers.*

Whilst the levels of service, as they apply to an organisation, are typically reflected in the asset management strategy and objectives, they are also ultimately reflected in the level of service delivered by the network and by each element. Accordingly, the asset management system should include methods for monitoring, measurement, analysis and evaluation of asset performance and the effectiveness of its assessment management system to deliver these services.

Service levels therefore should be understood to account for the value provided by an asset or network element to its customers.

Considering asset condition and performance in the context of the asset’s operating environment leads to an assessment of the remaining technical life of the asset. Whilst an assessment that an asset is at or near its end of technical life typically means that some form of intervention in the service provision is likely required to sustain service levels at the minimum long-run cost, assessment of remaining technical life is not sufficient reason of itself within an economic framework to retire and replace the asset.

Assessment of an asset’s technical end-of-life may be a trigger for establishing its economic end-of-life. However economic life may differ from technical life. Determining the economic life of an asset requires life cycle cost analysis to establish that retiring or de-rating the asset is the prudent first step. This analysis takes into account the impact on the cost of service of any remedial action(s) which would otherwise allow the service level to be maintained at the minimum long run cost of service.

BOX 5 – Determining technical end of life

There are a number of approaches to estimating the remaining technical life of an asset when accounting for asset condition, which may include:

- converting condition assessment and inspection information into an Asset Health Index, score or similar indicator. This indicator can be monitored over time, compared and correlated with other assets and other industry metrics, and should be the outcome of a consistent, repeatable, and well evidenced method;
- establishing a relationship between an asset health index (or similar) and the predicted end of life (or functional failure) of assets using probability theory and statistical methods to establish and evidence the relationship; and
- estimating the remaining life of the asset, asset fleet, or portion of the asset fleet, to establish a candidate list of assets for considering remedial action within a finite planning period.

3.4 Deciding to retire or de-rate an asset or asset fleet

3.4.1 Asset retirement

Deciding whether to retire an asset on an economic basis requires comparing the total expected service costs (i.e. the cost of providing the service) of continuing to operate the asset (i.e. not retire the asset) with the cost of alternative options to provide the service(s). As the service cost of the asset (or portion of a fleet of assets) typically increases with time, the service cost will eventually exceed the long run service cost of an alternative option or combination of options.

Sections 4 and 5 discuss the approach to determining the service cost for ‘business as usual’ operation of the asset and the service cost for different options.

If indicates that an asset(s) is reaching the end of its technical life or its economic life, the asset manager, acting in the long-term interests of the consumer, would consider when is the optimal time to:

- retire the existing asset (or portion of a fleet of assets); and then
- (to the extent that it is required) implement the option(s)[16] with the lowest long-run service cost that can meet the required service level(s).

This represents two distinct decisions:

- recognising that the existing asset is (or will soon be) no longer efficiently meeting its required service levels at an efficient cost, and may need to be retired, and
- confirming the best option (or combination of options) that provides the required service levels at a lower service cost.

The objective of these decisions is to maintain the required service levels at the most efficient life cycle cost.

The approach of the asset's end of economic life may be identified by considering:

- expected material changes to the total service cost;
- material changes to the relevant conditions such as service levels; and/or
- opportunities presented by a lower cost solutions (which may occur in advance of the asset reaching the end of its technical life).

> ***BOX 6 – End of life considerations***
>
> It is useful to consider the end of life criteria that may apply to assets. The end of life decision is often associated with the time at which:
>
> - an asset is no longer capable of fulfilling its intended function;
> - continued operation of the asset results in a level of risk cost (reliability, safety, compliance, etc.) that exceeds levels such as those determined by reference to licence conditions, risk management principles like 'ALARP,' or the application of an appropriate risk framework; or
> - continued operation of the asset, as opposed to the implementation of other credible options to deliver the required levels of service, no longer represents the most efficient long-run cost to consumers.

The net benefits associated with the selected remedial action(s) will vary:

- with time, where the asset is characterised by an increasing risk of failure with time (i.e. it follows a wear-out characteristic), and/or where the input assumptions about service demands vary with time (for example, with changes in the demand forecast used for calculating the load at risk and expected unserved energy);
- depending on the strategy being considered, as they are likely to reflect different risk mitigation benefits and costs; and

16 In the case of a staged or multi-option solution, the combination of solutions with the lowest long-run service cost would be progressively implemented. Prior to committing to subsequent stages, reassessment should be undertaken as updated/new information progressively becomes available.

- due to the uncertainty of the cost of the options being considered.

Asset retirement decisions may not be solely in response to a change in the asset's capability to achieve the required service levels or actual or forecast changes to the service cost. Where opportunities to lower service cost while maintaining the required service levels are identified, the economic value of these options should be determined by the NSP.

The NER requires that annual planning reviews consider non-network options in response to decisions for asset retirement, and these are to be reported in the APRs. This includes details of the NSP's methodologies and assumptions for deciding that it is necessary or prudent to retire the network asset, taking into account factors such as asset condition.

The information required to be published, and which is required for assessing capex projects, includes other reasonable network and non-network options considered to address the actual or potential constraint or inability to meet the network performance requirements.

> ***BOX 7 – Benefits associated with the investment need***
>
> The benefits from taking some form of intervention may include:
>
> - a reduction in the expected risk costs, that may include obsolescence costs;
> - realisable efficiencies in operations;
> - realisable capital salvage value (if any); and
> - minimising costs associated with non-compliance.
>
> These benefits reduce the expected service costs for the given service level.

In summary, quantifying the service costs associated with an asset retirement decision and comparing the monetised benefit from implementing an alternate solution with a lower service cost is the basis for economic decision-making. Justification for retiring individual assets or portions of asset fleets therefore requires demonstrating that:

- there is an identified need that consideration of asset retirement (e.g. due to the assets assessed condition, performance or operation);
- the prudent and efficient action (i.e. in terms of scope, cost, and timing) has been selected through comprehensive and robust options analysis that considers and accounts for uncertainty[17]; and
- the proposed action (in terms of scope, cost, and timing) is justified considering broader network plans, and the capability to deliver any outcomes efficiently.

3.4.2 Asset de-rating

The decision to de-rate an asset is similar to the decision to retire an asset.

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17 The efficient option may be no further action subsequent to retirement of the asset if it has or is forecast to have no enduring purpose (e.g. because of changes to the operating environment).

The trigger for deciding that an asset should be de-rated may arise from a change in the operational environment, or due to the assets condition, performance or operation. The outcome is that the asset is assessed as no longer being capable of efficiently fulfilling its design capability and capacity at its current rating. In absence of the de-rating decision, the likely risk is premature asset failure (i.e. failure before the assets technical life) due to accelerated physical deterioration. This may or may not be associated with a heightened risk of a current consequence (e.g. reliability, safety, etc.) and associated risk cost.

Conversely, the revised rating of an asset is likely based on consideration of what would prolong the asset's continuing function without accelerated physical deterioration, and/or without heightened likelihood of failure.

Like asset retirement, the decision to de-rate an asset is therefore also a technical and economic decision.

The decision to de-rate an asset may not give rise to an identified need for any subsequent investments, for example in cases where:

- de-rating does not lead to a constraint or non-compliance; or
- the asset is assessed to have no enduring purpose, in which case the asset can be retired (in due course) without subsequent investment; or
- it is efficient to accept a higher level of risk cost on an ongoing basis as no alternative options that provide a lower service cost are available.

However, the decision to de-rate an asset may also lead to subsequent investment, and thus economic analysis is required to determine the best option (or combination of options) to maintain the required service levels at a lowest long run service cost. This is elaborated upon in sections 4 to 6.

4 Decisions following an asset retirement or de-rating decision

This section describes how to identify and analyse options in response to a decision to retire or de-rate an asset or a portion of an asset fleet. The option (or combination of options) selected should provide the least cost approach to maintain the required service levels on an economic basis.

The economic end-of-life of an asset or a portion of an asset fleet is established by comparing the expected service cost for continued operation of the asset(s) with the expected service cost of available options (which may or may not require investment). If there is at least one option that provides the required service levels at a lower long run service cost than maintaining the asset's 'business as usual' (i.e. the counterfactual) operation, then the asset may be at the end of its economic life. Options analysis therefore provides the foundation for:

- deciding if asset retirement is the prudent and efficient option; or
- if deferral of asset retirement is the prudent and efficient option (e.g. via investing in life extension or risk mitigation through de-rating and/or the use of non-network solutions), and
- deciding what is the prudent and efficient option (or combination of options) to pursue subsequent to an asset retirement or de-rating decision; and
- establishing the prudent and efficient timing of the above options (or combination of options).

In all cases the preferred option (or combination of options) is that which maximises net economic benefit. For example, life extension, a non-network option, or an initial small scale action[18] can maintain option value and defer more substantive network option investment.

If investment is required to meet the identified need, it may involve (i) opex,[19] or (ii) capex,[20] or (iii) a combination of opex and capex.[21] Furthermore, the investment may involve several stages over time.

4.1 Aspects of the decision

The decision around the specific action (if any) to retire or de-rate an asset (i.e. based on deciding that an asset is approaching the end of its economic life[22]), and the options analysis that supports it should be based on the follow aspects, which we consider in turn:

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18 Such as an operating restriction on personnel coming within proximity of equipment to mitigate safety consequences and therefore mitigating the risk cost of asset failure, or network rearrangement to reduce the impact of asset failure, or asset refurbishment to reduce the likelihood of asset failure.

19 For example, increased maintenance or minor repair, or commitment to a non-network solution such as demand management.

20 For example, refurbishment.

21 For example, a period of increased maintenance prior to pursuing an asset retirement option.

1. identifying the asset's purpose (i.e. service level requirements) for the foreseeable future;
2. quantifying the expected service cost of the asset remaining in service. This is the 'business as usual' or counterfactual case;
3. identifying options to maintain required service levels at the minimum long-run cost to consumers;[23]
4. quantifying the expected service cost of each option (or combined options)
5. selecting the prudent and efficient option (or combination of options) that minimises the total expected service cost with respect to the 'business as usual' case; and
6. determining the expected economically efficient timing (as indicated by the options analysis).

BOX 8 – Framework for identification of options

ISO 31000 provides a framework that can be applied to consider the potential list of credible options, in responding to an identified risk. In the case of network replacement expenditure planning, there is generally a risk that an asset's condition creates an expected increase in service cost above the cost of other service options.

The ISO 31000 framework is only one possible framework and NSPs should implement and maintain an asset management framework and decision-making process appropriate to their circumstances.

Risk treatment options are not necessarily mutually exclusive or appropriate in all circumstances. The options can include the following:

a) Avoiding the risk by deciding not to start or continue with the activity that gives rise to the risk;

b) Taking or increasing the risk in order to pursue an opportunity;

c) Removing the risk sources;

d) Changing the likelihood;

e) Changing the consequence;

f) Sharing the risk with another party or parties; and

g) Retaining the risk by informed decision.

ISO31000

As evident in the above analysis, the decision to remove the risk by replacing or refurbishing the asset is only one of several risk treatment options to consider.

22 Or, in the less common case where the asset may have significant remaining technical life, but it may be at the end of its economic life because an opportunity to use an alternative solution to ensure the service level is met (e.g. via local generation rather than by transport over poles and wires).

23 Options or combination of options may include changes to operational practices, network reconfiguration, de-rating, life extension, service support or non-network options, as well as asset retirement and more substantive subsequent network investment options.

4.2 Identifying the asset's purpose

To establish the 'business as usual' or counterfactual case, and to identify options, relevant costs and benefits, it is important to clearly establish the ongoing enduring purpose of the asset(s) being considered for retirement or de-rating.[24] An assets purpose is typically considered in terms of the service levels it provides over a relevant timeframe, and has implications in analysing the available options (or combination of options). For example:

- if the service levels the asset(s) provides are expected to be required over the long term at current or increased levels of service, then options that incorporate the scope for meeting the changed purpose should be included in the analysis;[25]
- if there is reasonable uncertainty in the medium to long term about the required service levels or the need for the asset,[26] it may be that increased maintenance, implementation of operational controls, refurbishment, or non-network options may be prudent individually or in some combination;
- if the asset(s) may no longer be needed within the medium term, then it is more likely options such as operational controls, increased maintenance, network configuration, or non-network options may be prudent and efficient.

As with all aspects of expenditure justification, it is important to assemble evidence to support assumptions and parameters. This should include evidence to support the claimed change in purpose of the asset,[27] noting any uncertainty in the scenario(s) which gives rise to the change in purpose.

BOX 9 – Reviewing the enduring purpose

Given the rapidly changing energy landscape, and subdued demand growth forecasts, network and asset management planning should consider the enduring need for assets in terms of the service levels required and any uncertainty in the level of service required. The potential for the following options, or combinations of the following options should be considered to maximise option value:

- non-network solutions;
- asset life extension;
- changing the network configuration;
- changing the operation of the asset(s) or de-rating the asset / element; and
- removing the network asset / element.

Network and asset management plans should consider the ongoing levels of service required and the uncertainties involved and consider holistically whether the assets and network's current form and function has an ongoing or enduring purpose. Or, whether through options, or combinations or options, such as those noted above, the required service levels can be met more efficiently.

24 For example, this could occur due to the anticipated impact of DER at the fringe of grid.

25 For example, rather than replacing the asset on a like-for-like basis, increased functionality/capacity may be justified, and such options should be considered in the options analysis.

26 For example, peak demand in an area may be falling, or a load or generator which the asset supplies is may be decommissioned at some future time.

27 Where the capacity of functionality of the asset is enhanced then a cost benefit justification would be required.

4.3 Quantifying the expected service cost – ‘business as usual’

When analysing options for asset retirement or de-rating decision-making, the counterfactual (or base case) is the ‘business-as-usual’ (BAU) service cost. That is, the expected cost to be incurred if the asset is not retired or de-rated but remains in service, operated, and maintained on a BAU basis.

The cost and benefit of other options are compared against the BAU counterfactual as part of the option selections process.

It should also be recognised that all costs in such analyses are inherently uncertain (i.e. they are not precise). For example, it is difficult to objectively and quantitatively forecast the likely performance of an asset in the distant future.

Risk management deals with uncertainty, including the uncertainty of asset performance. Risk management enables uncertainty to be objectively managed by accounting for variation, envisioning possible scenarios, and making forecasts based on what is considered probable within a range of possibilities.

Risk management techniques can be applied to quantitatively value the risk cost associated with asset performance and any other costs relevant to estimating an expected total service cost. Stochastic modelling, scenario analysis, and sensitivity analyses should be applied (as discussed in this section and in section 5). Monetising the risk of asset failure[28] is an essential aspect of options comparison within an economic framework, as it provides a common basis for comparison of a broad range of investments and their timing.

The expected BAU service cost is the total cost of continuing to meet the required service levels with the existing asset, or fleet of assets, and comprises the aggregate costs from:

- risk costs associated with the asset’s expected performance (e.g. expected consumers costs arising from asset failure) and the associated consequences which have an economic value. Typically the key risks include:
    - supply reliability risks;
    - health and safety risks;
    - environmental risks;
    - emergency response and plant damage risks;
- replacement and disposal;
- operations and maintenance (including minor repairs, costs arising from any developing obsolescence, costs arising from any developing additional operational requirements or difficulties); and
- spares holdings.

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28 Where failure is generally considered as ‘functional failure – i.e. the asset can no longer perform its intended function. It may or may not be repairable – this is taken into account in the risk cost assessment.

BOX 10 – Example service cost considerations – switchgear

The service costs for a circuit breaker may include:

- Risk costs:
  - reliability risk associated with loss of supply resulting from protection operation of an upstream device, resulting in interruption of load to consumers whilst contingency provisions can be implemented (e.g. network switching);
  - safety risk associated with explosive failure, and injury to an industry worker in proximity at the time of failure;
  - environmental risk associated with discharge of oil (or other materials) that requires remediation works or incurs fines;
  - damage to adjacent plant and infrastructure arising from explosive failure; and
  - other financial costs, arising from investigations, compliance breaches, litigation, or insurance events, etc.;
- Emergency repair / replacement and disposal costs of the failed switchgear unit to restore the service;
- Replenishment of spares holding, should spares have been utilised in response to the event (though without duplicating the cost of replacement of the failed unit); and
- Ongoing operation and maintenance costs associated with maintaining this asset in service.

For other asset types, other costs may be considered, such as costs associated with bushfires for conductor failure, or the potential for injury to members of the public.

As an asset's condition and/or performance deteriorates over its lifetime, the expected service cost will increase because:

- the probability of in-service failure increases with time, and therefore the expected risk costs increase; and
- the expected cost of operating and maintaining the asset increases as the asset's condition and/or performance deteriorates with time.

Section 5 provides more information on calculating risk cost.

4.4 Identifying credible options

The risk associated with an event occurring that impacts on delivery of the required service levels is determined from the probability of the event occurring, the consequence (or consequences) of that event occurring, and the likelihood of the consequence (or of each of the consequences) occurring given the event has occurred. The risk that an asset fails to meet the required service level can arise from multiple events (or causes). In selecting credible options as alternatives to the BAU approach (counterfactual or Base Case), each option should be considered in regards to its ability to:

- reduce the probability that the event will occur (preventative controls); and/or
- reduce the consequences of the event occurring (mitigating controls); and/or
- reduce the likelihood of the consequence (or consequences) occurring (mitigating controls).

The RIT-T[29] and RIT-D[30]Application Guidelines provide relevant advice for the selection of credible options, in that they:

- each address the identified need;
- are commercially and technically feasible; and
- can be implemented in sufficient time to meet the identified need.

In the RIT-T Guidelines, the AER also considers that a credible option may include:[31]

> *‘a decision rule or policy specifying not just an action or decision that will be taken at the present time, but also an action or decision that will be taken in the future if the appropriate market conditions arise.’*

4.4.1 Business-as-Usual (base case)

Continuing to operate the asset, deferring the retirement decision (cognisant of the likelihood of asset failure and the associated risk costs) is typically referred to as the BAU, counterfactual, or base case. It is essentially defined as continuing to operate the asset(s) applying standard operating and maintenance practices over the assessment period.

A BAU base case may involve run-to-failure, where this is the default asset management strategy for the relevant asset(s). A ‘run to failure’ strategy is usually only economically viable for assets that do not present significant reliability, safety, or environmental risks and where responding to the asset in-service failure does not involve an excessive premium over the pre-emptive replacement.

4.4.2 Alternative credible options

The alternative credible options that warrant consideration when undertaking asset replacement planning include:

- life extension, via:
    - operational strategies – which defer asset retirement. For example:
        - operational/administrative controls that manage the consequence or the likelihood of the consequence associated with asset condition;
        - increased maintenance (including minor refurbishment) – which reduces the likelihood of failure events;

29 AER, *RIT–T application guidelines*, 2017, Section 3.2, p. 8.
30 AER, *RIT–D application guidelines*, 2017, Section 8, p. 29.
31 AER, *RIT–T application guidelines*, 2017, Section 3.2, p. 8.

    - non-network solutions – which defers the asset retirement by reducing the cost of consequence. For example by reducing the load's dependency on the network.
    - network configuration and/or functional capability – which reduces the cost of consequence. For example by reducing the consequence through reduced loading or reduced outage duration.
  - repair / refurbishment – which defers asset retirement. For example, repairing the worst oil leaks on an underground cable, or refurbishing assets such as by pole reinforcement.
- asset substitution, via introducing a non-network solution – which may mean that the asset can be:
    - retired but not replaced. For example, rather than replacing a distribution line, arranging for consumers to be supplied via alternative arrangements such as a stand-alone power system, or
    - de-rated, such that the asset has a lower duty, and therefore presents a lower failure likelihood;
    - retired but replaced with an alternative (lower cost) network solution or through a combination of staged options;
- asset replacement with different technology or modified functionality[32] – for example replacement of a power transformer with reduced capacity and supported by non-network options, load control, or network automation to manage loading;
- asset replacement with a similar technology/functionality:
  - partial (or strategic) replacement;
  - brownfield asset (or site) re-development – may be a more economical solution than a greenfields re-development. This may also consider alternate and newer technologies such as Vacuum or Gas insulated switchgear may be more economical than air-insulated switchgear in some circumstances (e.g. where there are space constraints);
  - greenfield asset (or site) development – e.g. building a new substation.
- a combination of options implemented together or in a staged fashion to maintain option value and reduce the consumer's long term service cost.

[32] Where the functionality of the asset is enhanced then a cost benefit justification would be required.

BOX 11 – Example asset treatment options – circuit breakers

Having assessed a switchboard's condition and determined that intervention is likely to be prudent, a reasonable set of treatment options should be explored before determining that asset replacement is a prudent and efficient treatment. This involves considering the BAU service costs and treatment options to avoid asset retirement. These options should include, but are not limited to:

- maintaining the existing asset to extend its service life through additional maintenance activities;
- manage replacement through rotating spares, including refurbished units;
- refurbishment, which could for example include replacement of oil circuit breakers with a vacuum circuit breaker trucks;
- reducing the load on the switchboard though network reconfiguration, network automation, demand management or other non-network options (e.g. energy storage);
- implementing operational controls such as limiting access, remote or dead-switching protocols, etc.; or
- a combination of options together or staged to maintain option value and reduce the customer's long term service cost.

Having determined that the switchboard's retirement is the prudent and efficient treatment, and after having confirmed that the switchboard has an enduring need and established the expected service levels required, options should be explored to address the ongoing service need. These options would include but are not limited to:

- replace part of, or the entire switchboard in-situ;
- replace part of, or entire switchboard in an extended or new building (or suitable enclosure);
- replace part of, or the entire switchboard with new technology that may provide additional functionality, or lower life cycle cost, etc. (this is likely to require a cost benefit justification); or
- a combination of options together or staged to maintain option value and reduce the customer's long term service cost.

The efficient timing for investment in any of these options (including the option of retiring an asset) should be subject to life cycle costing analysis. This would require comparing the life cycle cost of the various options with each of the alternative options and the BAU base case. Efficient timing of the treatment option, or combination of treatment options (together or staged) is the investment timing that minimises the customer's long term service cost.

4.4.3 Option value

Higher levels of uncertainty in the future operating environment requires greater focus on options to defer significant investment, and particularly investment in fixed assets. Some uncertainties may resolve with time, and with time a greater range of options may become available.

The value realised from maintaining investment flexibility, using small scale actions to manage service level outcomes, and deferral of significant investment in fixed assets will preserve economic 'option' value that reduces long term costs to consumers. For example:

- where significant uncertainties may be resolved with time and materially affect the selected preferred option, then there is an 'option value' in deferring action; and/or
- smaller and/or incremental (staged) options tend to be preferred where the benefit of a more significant investment option is uncertain; that is, the smaller option, or staged set of options will tend towards a 'minimal regrets' outcome.

Where possible, NSPs should explore all credible options (or sets of options) that provide flexibility to respond to uncertainty.

For example, some significant uncertainties that need to be accounted for in asset retirement and replacement decisions include (but are not limited to):

- changes to network service requirements;
- changes to consumer demand levels and demand patterns (geospatial and temporal);
- changes to generation patterns including distributed generation;
- the implications of energy storage on consumer service levels and asset utilisation;
- technology change including the implications of energy efficiency, communication and controllability;
- asset condition deterioration rate and likelihood of in-service failure; and
- the risk cost associated with asset performance.

4.4.4 Quantifying the service cost of alternative options

A similar process to quantifying the service cost (including evaluating the risk cost) needs to be undertaken for each option, as is undertaken for the BAU case (discussed above). Depending on the timing, some options will greatly reduce the service cost (risk component) of asset failure, but rarely eliminate it.

A combination of options can often form the best overall approach (as measured by minimising the long-run service cost under a range of scenarios and input sensitivities). The service cost of combinations of options (or staged options) should also be developed, noting that the risk cost will be 'reset' to a lower 'starting point' following the assumed implementation of any intervention that has the effect of lowering the likelihood of an event, the likelihood of the any consequence(s), and/or the cost of any consequence(s).

Care needs to be taken with combination options not to 'double count' risk cost reduction benefits or the costs involved in achieving risk cost reduction.

4.5 Selecting the preferred option

The preferred option is the credible option that maximises the net economic benefit compared to all other credible options (including BAU) and represents the maximum long run net benefit across the NEM.[33]

4.5.1 Economic cost benefit components and estimates

Economic cost benefit components of options typically comprise of one or more of:

- market benefits;
- risk cost reduction or avoidance benefits;
- efficiency savings and avoided operational costs (e.g. from extra functionality, or changes to inspection and maintenance practices);
- operations and maintenance costs;
- capital cost of implementing the solution;
- the value of optionality; and
- capacity stranding costs.

Benefits and costs of the options may be presented in gross terms, or relative to the BAU case. NSPs must be careful in defining the benefits and costs, such that the difference in costs and benefits between the counterfactual and any one of the options genuinely reflects the differences between those scenarios. For example, avoided costs or cost reductions may be modelled 'benefits'; or the gross costs of each option and the counterfactual can be defined such that modelling simply considers the lowest cost option.

Where different options have different cost profiles, but provide exactly the same benefit, then assessment may involve analysis to determine which option has the lowest Net Present Cost.

There should be evidence for the quantum and timing of all cash flows and cash flow elements in the analysis to demonstrate the reasonableness of the assumptions for each option and the BAU (counterfactual).

4.5.2 Discount rate

The method for determining the appropriate rate(s) used to discount cash flows when analysing options is discussed in the RIT-D Application Guidelines and the RIT-T.[34] The version of these documents that are in effect when this analysis is performed should be referred to for guidance.

33 Consistent with the requirements of the RIT–T and RIT–D application guidelines.

34 AER, *RIT–T*, June 2010, paragraphs 14 and 15(g); AER, *RIT–D application guidelines*, 2017, p. 20.

4.5.3 Modelling periods

The principles for setting the duration of the modelling period include:

- accounting for the size, complexity and expected life of the relevant credible option;
- accounting for the reasonable expected life of the BAU base case; that is, the period for which the BAU regime can reasonably be expected to apply;
- providing a reasonable indication of the market benefits and costs of the credible options;
- to the extent possible, constructing credible options that require assessment under similar modelling periods; and
- the type and extent of scenarios that describe a reasonable range of futures.

The method for determining suitable modelling periods is discussed in some detail in the RIT-T and RIT-D Application Guidelines[35] and these should be referred to for guidance.

4.5.4 Terminal values

Terminal values are values of expected net economic costs and benefits beyond the modelling period. The preferred approach is to minimise the impact of the terminal value by choosing a modelling period that captures the year-by-year benefits and costs such that sensitivity to the terminal values is minimised. To the extent that terminal values are required, then care is needed to ensure that they are reasonable, evidenced (as far as reasonably practical) and where possible, that the retirement decision and choice of option(s) is not dependent on one or more of the terminal values.

Care should be taken not to assume that net benefits will continue in perpetuity, and especially not that they will grow in perpetuity. Realistic specification of a BAU counterfactual will guard against this, by allowing for action to be taken to address the 'identified need' at some point in time, such that the option (or set of options) being considered will not have a net benefit beyond that time.

4.5.5 Scenarios and sensitivity analyses

Confidence in options analysis, and in the evaluation of service cost and particularly risk costs, can be improved by considering a reasonable range of scenarios and undertaking sensitivity analysis.

When applying a RIT-T or RIT-D the NER requires that proponents base their assessment on:

> *'a cost-benefit analysis is to include an assessment of the reasonable scenarios of future supply and demand'.*[36]

Scenarios should be constructed to express a reasonable set of internally consistent possible future states of the world. Each scenario enables consideration of the prudent and

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[35] AER, *RIT–T application guidelines*, 2017, p. 39; AER, *RIT–D application guidelines*, 2017, p. 31.

[36] NER clause 5.16.(c)(1) for the RIT–T. NER clause 5.17.1(c)(1) also makes reference to this effect for the RIT–D.

efficient investment option (or set of options) that deliver the service levels required in that scenario at the most efficient long run service cost consistent with the National Electricity Objective (NEO).

Sensitivity analysis enables understanding of which input values (variables) are the most determinant in selecting the preferred option (or set of options). By understanding the sensitivity of the options model to the input values a greater focus can be placed on refining and evidencing the key input values. Generally the more sensitive the model output is to a key input value, the more value there is in refining and evidencing the associated assumptions and choice of value.

Scenario and sensitivity analyses should be used to demonstrate that the proposed solution is robust for a reasonable range of futures and for a reasonable range of positive and negative variations in key input assumptions. NSPs should explain the rationale for the selection of the key input assumptions and the variations applied to the analysis. The RIT-T and RIT-D Application Guidelines nominate several key input assumptions for the base case and for sensitivity studies.

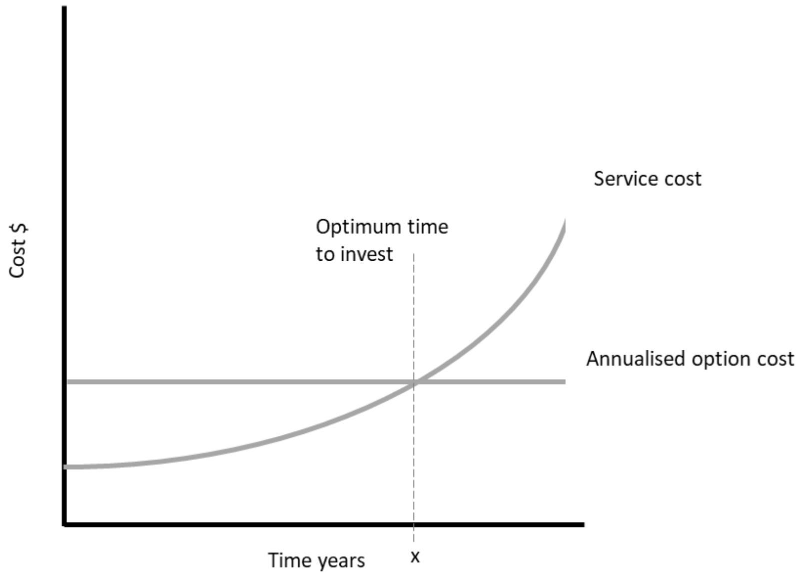
4.6 Determining the optimal timing

The annual benefit of implementing an alternative to the BAU counterfactual is the difference between the total service cost of the proposed option (or set of options) and the total service cost of the counterfactual. The benefit will be positive if the service cost for the proposed option (or set of options) is less than that for the counterfactual (i.e. the benefit equals the avoided service cost). For assets that follow a wear-out pattern, the annual benefit typically increases with time due to increasing maintenance and repair costs and/or increasing avoided risk costs.

The economically prudent and efficient timing for asset retirement is indicated by the annual benefit from the proposed option exceeding its annualised cost.[37] This is illustrated in Figure 1 below.

[37] This comparison should be undertaken using dollars expressed in consistent value terms (real dollars) and involves applying a reasonably appropriate discount rate and life for the option.

Figure 1:Stylised representation of economically optimum timing of investment



The derivation of the service cost, being an aggregate of a number of components of service costs as explored in this section, is discussed further in section 5.

4.7 Ensuring non-network solutions are considered

Good electricity industry practice suggests that NSPs proactively identify and apply non-network solutions, before identifying a network limitation or constraint, particularly where a viable non-network option may present a lower service cost outcome for consumers. For example, NSPs may develop a series of case studies regarding demand management projects that include both non-network projects developed in response to identified network constraints, and innovation projects that have been initiated under the Demand Management Innovation Allowance. These case studies may assist investigating opportunities for the NSP to deploy as potential solutions to limitations or constraints on the electricity network.

The NER includes obligations on NSPs to investigate and assess non-network and demand-side opportunities as alternatives to network investment options. A key component of these obligations is the development of a Demand Side Engagement Strategy[38] for DNSPs. The requirements for a Demand Side Engagement Strategy aim to assist DNSPs (i) engaging with non-network providers; and (ii) considering non-network options.

The NER further requires that NSPs adopt planning frameworks that incorporate the use of non-network alternatives into the network wherever they present the most economic option. These are now required to be considered when undertaking asset retirement planning. Examples include considering (i) embedded distributed generation (fixed and mobile); (ii)

38 A demand side engagement strategy is contained in a demand side engagement document as required under NER clause 5.13.1.

demand response, including curtailable and interruptible loads, and (iii) energy storage systems.

As part of the network planning processes, NSPs must identify specific locations where there are existing, or emerging, limitations, and publish information regarding them in the APRs and related documents. This information provides opportunities for service providers to offer options for network support. In addition, and at any time, providers can approach NSPs with proposals based on the currently published information.

In addition, new tools are emerging such as the Australian Renewable Energy Agency sponsored 'Network Opportunity Maps' that provide an overview of network and generation opportunities for proponents. With timely and appropriate information from NSPs these tools can help identify opportunities to lower service costs for consumers.

5 Risk-cost assessment methodology

This section sets out a methodology to estimate the expected risk cost that is consistent with the principles outlined in section 2. Other methods that achieve these principles may be more applicable to the circumstances of individual NSPs. As such, we encourage NSPs to develop and continue to refine asset management and risk assessment practices that are appropriate to their particular circumstances.

The method set out below is intended to illustrate the application of asset risk assessment, and to communicate the economic need for and timing of asset retirement and de-rating decisions.

5.1 Simplified quantitative approach

5.1.1 Defining risk costs

Risk cost assessment can quantify or monetise the risk of events occurring which could cause disrupt the maintenance of the required service levels. Asset failure is usually the driver of the most significant risk costs.

A simplified quantitative approach can determine the risk cost that includes the following elements, as expressed in Figure 2 below:

- probability of asset failure;
- the cost of consequence of the asset failure;
- the likelihood of the consequences of the asset failure being realised given the failure has occurred39; and
- the number asset units to which this analysis relates.

Figure 2: Risk cost equation

This approach can be represented as an equation as shown below. This is, where the probability of failure is expressed at an asset level,[40] and the annual risk cost is calculated for a single event or failure mode.

Consistency is essential in deriving the scaling factor (No) and moderating factor (LoC):

39 E.g. the reliability, safety, financial, and legal/compliance consequences.

40 In terms of transmission or distribution lines, the asset may be defined in terms of line segments or line length.

- the PoF in the formula above is assumed to be an annual probability of a failure for an asset;
- the derivation of the PoF and the number of units must be consistent (e.g. if the probability of failure is defined per kilometre of overhead line, then the units should be kilometres);
- the definition of the consequence of the failure event and the derivation of the likelihood of the failure event occurring (e.g. if the consequence is the 'worst-case' then the LoC is the likelihood of the worst-case consequence being realised)

$$Risk\ cost\ per\ year\ of\ event\ n\ (\$) = \sum_{n=0}^{n} (PoFn\ \times Non) \times (\ LoCn\ \times CoCn\ )$$

Where:

- PoF_n *= Annual Asset Probability of failure event n (%)*
- No_n *= Number of assets*
- LoC_n *= Likelihood of Consequence of failure event n (%)*
- CoC_n *= Cost of consequence of failure event n ($)*
- *n = individual failure event (or failure mode)*

As discussed in section 4, the risk cost avoided by implementing an option to address the identified risk can be expressed as an input to the economic options assessment model, as a benefit, that is, as the risk cost that will be avoided or not incurred by adopting the option. Care should be taken to recognise the expected reduction in the risk cost achieved by each option, as not all options will equally reduce or fully eliminate the risk cost. Any additional quantifiable benefits[41] and costs[42] are also included to determine the net economic benefit (if any) from implementing the option (or set of options).

There may be a combination of consequences that are required to be modelled for any individual failure event or failure mode, and which require a combination of values for the derivation of the $(\ LoCn\ \times CoFn\ )$ component of the above equation. Consequences also may arise only as a result of a combination of multiple failures, in which case the relevant probability is the conditional probability of all of the circumstances occurring, that lead to the consequence cost occurring. This is particularly relevant where the design of the network includes redundancies, or where there are procedural or engineering controls that modify the probability of an event or its consequence(s).

5.1.2 Risk consequence areas

To assist understanding the total risk cost, risk consequence areas are nominated that reflect the nature of different consequences arising from the failure of an asset. These would normally align with the risk management framework already in place within the NSP.

Typical risk consequence areas are denoted in Table 2 below.

41 Such as savings from efficiency improvements.

42 Such as the cost of implementing the option or set of options.

Table 2: Typical consequence areas

Risk consequence area	Elaboration of consequence
Reliability & security	This refers to the system reliability and security consequence to the network arising from the failure of an asset. The monetised value of the consequence typically considers: • the amount of load at risk of interruption (MW); • the duration of loss of supply; and • a value per MW of lost load for each consumer type. This consequence is typically valued via the Value of Consumer Reliability (VCR) applicable to the consumer type affected by the supply interruption.[43]
Safety & health	This refers to the safety and health consequence to workers (staff, contractors) and/or members of the public arising from the failure of an asset. The monetised value of the consequence typically considers costs for: • deemed loss, to the affected individual or their family of an injury or fatality; • loss of productivity; • any other related costs (which must be reasonably likely to be incurred and adequately justified) This consequence is typically expressed in terms of the Value of Statistical Life (VSL).
Environment	This refers to the environmental consequence to the surrounding community, ecology, flora and fauna arising from the failure of an asset. Notable environmental consequences are bushfire or contamination (e.g. oil leakage). The monetised value of the consequence typically considers costs for: • property loss; • damages for personal injury or loss of livelihood; • deemed loss to the natural environment; • clean-up or remediation; • any other related costs (which must be reasonably likely to be incurred and adequately justified).
Legal / regulatory compliance	This refers to the legal or regulatory/legislative compliance breach arising from failure of an asset.

43 We expect to publish a set of relevant VCR metrics in December 2019.

	The monetised value of the consequence typically considers costs for: • investigations or inquiries; • legal fees; • fines, or penalties imposed; and any other related costs (which must be reasonably likely to be incurred and adequately justified).
Financial	This refers to the direct financial consequence (or loss) to the NSP arising from the failure of an asset. The monetised value of the consequence typically considers costs that are not taken into account in any of the above areas of consequence, and may include: • cost of replacement or repair of the asset including under emergency conditions, and the costs arising from damaged caused to other assets); • business disruption; • network support; • market costs that the NSP is liable for; • media liaison and community engagement; and • any other related costs (which must be reasonably likely to be incurred and adequately justified).

The NSP may elect to further split the list of consequence areas denoted in the table above to better understand or communicate its risk costs or to align with its existing risk management framework. In doing so, it must avoid duplicating consequences and associated consequence costs.

5.1.3 Identifying consequences using failure mode analysis

Determining asset failure modes will assist with identifying the consequence costs. For each failure mode, there is a failure event and one or more consequences. For each possible consequence, there is a corresponding likelihood of that consequence occurring, and that likelihood corresponds with the value of that consequence. The expected value of each consequence and expected likelihood should be used in risk cost analysis unless methods are used that account the full stochastic nature of the variable (e.g. Monte Carlo analysis).

Consequences and their likelihood can vary over period of time such as daily, weekly, seasonally or annually. Where variation is significant separate modelling of each time period may be required, however in most cases reasonable simplifying assumptions should be used.

The total risk cost is calculated by considering the likelihood of each failure mode, the value of the consequences for each failure mode and the likelihood of each consequence. Care should be taken to recognise any common mode or mutually exclusive failure modes or consequences, and appropriate conditional probabilities should be used in determining total risk cost.

It is important that any assumptions and any parameters or other input assumptions applied to modelling the risk cost are documented and formed on a sound basis. When the aggregate impact of these factors is included, a sense-check can be gained by considering the extent to which the analysis reasonably reflects the NSP's current operating environment and historical experience.

A representation of a single failure mode and the relationship between the failure mode, failure event, and typical consequence area are illustrated in Table 3 below.

Table 3: Illustrative failure events and consequence sources from conductor failure

Failure mode	Failure event	Consequence area
Conductor failure	Conductor drop	Safety: electrical contact
		Safety: bushfire
		Environment: bushfire
	Emergency (un-planned) outage	Reliability: supply interruption
		Financial including repair cost, property damage

5.1.4 Calculate the annual risk cost

The monetary value of risk (per year) arising from an asset failure is the sum of the expected value of the annual risk costs for each failure mode and the associated consequence expectation. The annual risk cost for year n, can be calculated according to the equation below.

$$Total\ Risk\ cost\ per\ year\ (\$) = \sum Risk\ cost\ per\ year\ for\ each\ failure\ event\ n(\$)$$

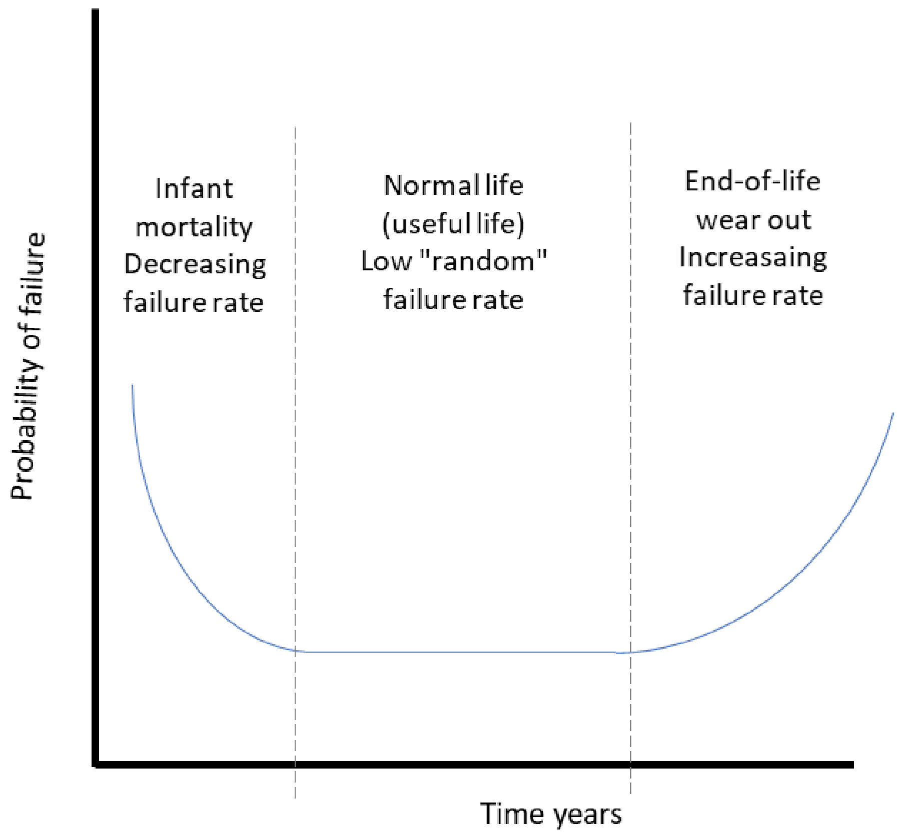
By modelling a probability of failure function and forecasting the likelihood and consequence costs into the future, the annual risk cost can be modelled into the future. This annual risk cost typically shows an increasing function over time, subject to the functions used for the three primary variables.

5.2 Assessment of failure probability

The probability of failure of an asset can be modelled as a function of time. Figure 3 below illustrates the 'bathtub curve,' which is generally used to illustrate the failure probability for the lifetime of a population of assets that exhibit wear-out characteristics. In the context of the assets managed by NSPs and for asset retirement considerations, the 'end-of-life wear-out' period is of most interest for those assets identified as exhibiting an increasing failure rate over time.

Some assets classes may display random failure (i.e. little or no correlation with age). Care should therefore be taken to provide evidence to support assumptions regarding increasing failure probability and the assumed rate of any increase, noting that this assumption will influence the efficient timing of retirement indicated by the economic analysis.

Figure 3: Stylised bathtub curve – hypothetical probability of failure versus time



A common approach to predicting an asset/asset class' probability of failure is to use past failure data to derive a relationship between an asset's age and its probability of failure at that age. This is typically done by fitting the historical 'time to fail' data to a statistical distribution and two approaches are common: use of a Weibull distribution or using the Crow-AMSAA approach, as described below.

Common methods of statistical distribution

The Weibull probability methodology is commonly used where a single asset failure mode is the dominate source of failure. The failure rate r(t) (which is the probability of failure over time) is determined according to the following two-parameter equation.

$r(t) = (\beta\ t^{\beta-1}) / \eta\beta$

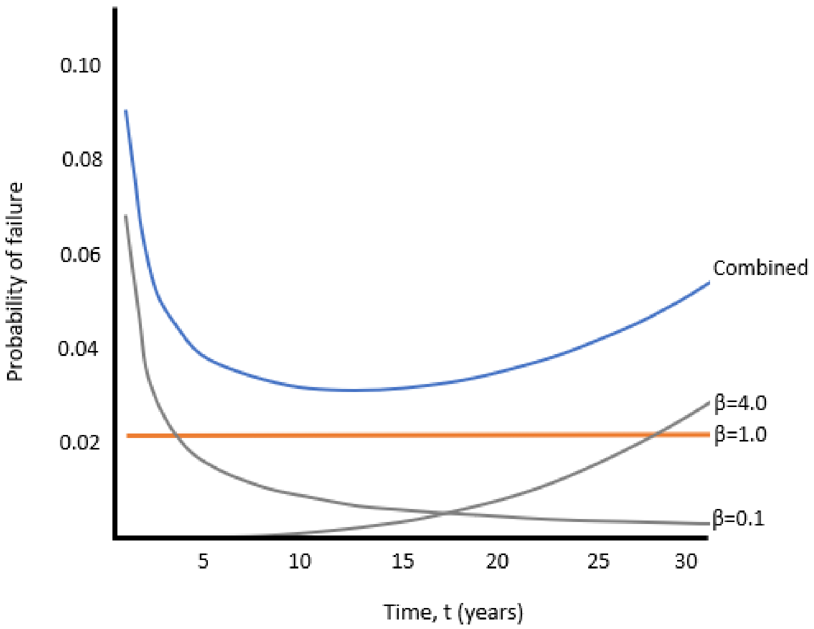
where,

- *t = time*
- *η (eta) = characteristic life*
- *β (beta) = shape parameter*

Eta (η) is referred to as the scale parameter, and for an asset population it is the characteristic life (or the mean time between failure).[44] Beta (β) is the shape characteristic and, as illustrated in the figure below, it determines the rate of increase of failure. A β value >1 indicates that the failure rate is increasing, β = 1 indicates a constant failure rate, and β <1 indicates a declining failure rate.[45]

There are methods available to estimate vale of the Weibull distribution parameters including the method of least squares, the weighted least square method, the maximum likelihood method and the method of moments. In most applications the maximum likelihood method will provide good estimates, or in cases with very small sample sizes, the weighted least square method may provide good estimates. In all cases it is important to document the method and assumptions used in determining the distribution parameters.

Figure 4:Failure rates with variation of β (illustrative)



Source: AER – illustrative only

An alternative to predictive failure rate modelling based on the Weibull distribution is Crow-AMSAA plots, which are more suitable for predicting future failures for mixed failure modes in linear systems.[46] The Crow-AMSAA technique involves plotting cumulative failures over time (log-log), with a line of best fit described by the following equation.

n(t) = λ tβ

where

- *β is the line slope,*

---

[44] The Mean Time Between Failure (MTBF) is the time when 63.2% of cumulative failures occur for a particular asset population.

[45] P. O'Connor and A. Kleyner, *Practical Reliability Engineering*, 5th Ed, Wiley, 2012, p. 37.

[46] Such as cables and lines.

- *λ is a ‘scale factor’, and*
- *n(t) is the failure event at time t.*

As with Weibull curves, a β value >1 indicates that the failure rate is increasing, β = 1 indicates a constant failure rate, and β <1 indicates a declining failure rate.[47]

Where parameters are derived from an NSP’s data, care is required to take account of the statistical level of confidence in the derived relationship. Where statistical level of confidence is low, then sensitivity analysis becomes increasingly important. Reference to industry data sets or parameters based on industry data should also be used to provide confidence in any parameter estimates.

5.2.1 Approach

Table 4 below illustrates the typical process for forecasting the probability of failure time series (or rate of failure) for asset classes and individual assets.

Table 4: Derivation of probability of failure for an asset class and/or individual asset

Steps	Description
1. Collect asset end of life failure data	Asset failure data is derived from either the NSP’s own records or from industry data sets or a combination of the two. The objective is to obtain sufficient age-at-failure data for the asset class or individual asset to be statistically valid as a basis for deriving the probability of failure time series for that asset or asset class.
2. Inclusion of asset replacement data	The age of assets at replacement data points can also be considered. However, this data must be treated differently to age-at-failure data because it pre-empts asset failure and implicitly creates a circularity because it depends on past replacement strategies and criteria.
3. Select failure distribution methodology	Typically, Weibull distributions are applied for assets with wear-out characteristics and single mode failures are contemplated. Alternatives can be selected, but evidence needs to be provided to support the selection and application.[48] This step is a critical input to the application of software tools for deriving the modelling parameters (i.e. such as β and λ)
4. Derive probability of failure distribution parameters	Several NSPs use off-the-shelf software[49] for this step. The modelling approach selected should be commensurate with the failure modes of the asset class.

47 N. Comerford, Crow/*AMSAA Reliability Growth Plots*, 2005, pp. 1–22. See also P.E. Barringer, *Predict Failures: Crow-AMSAA 101 and Weibull 101*, 2004, pp. 1–14.

48 For example, the Crow-AMSAA reliability growth plots have been applied for predictive failure modelling of assets with mixed failure modes.

49 Such as Availability Workbench, by Isograph.

5. Generate probability of failure time series function	The output of step 4 is the probability of failure in a time series for the asset class (i.e. if data from the whole asset class population was the basis of the input data) or for individual assets (i.e. if the input data was applicable to a single asset). The results of step 4 should be tested against the actual failure data and the parameters adjusted as necessary to achieve a reasonable correlation between predicted and actual failure rates.
6. Calibrate probability of failure function to individual assets	Considering the importance of having sufficient data points to derive representative probability of failure time series, typically data from a whole asset class population is used. Individual asset probability of failure time series can be derived from the population results by calibrating the population average and variance with individual asset information.

BOX 12 – Importance of sensitivity and confidence

The application of sensitivity analysis to demonstrate that the analysis is robust reflects good practice, but the application of a sensitivity analysis does not in of itself address any underlying systemic bias that may be present in the assumptions and input parameters applied in the modelling.

Accordingly, steps should be taken to demonstrate that the assumptions and input parameters selected are robust. This may be achieved by developing confidence bands for key input parameters, validating against other empirical evidence and observations, considering the results of 'post mortems' on failed and retired equipment, back casting of models to demonstrate goodness of fit of key outputs, comparison with similar industry based analysis, commissioning external / independent review and verification, or other similar methods .

Equally important is validation of the model itself, including the logic and mechanics of the modelling to provide confidence in the analysis results.

In a recent revenue determination, we observed that *'… stakeholders (and their advisers) were not in a position to adequately scrutinise the benefits and costs of the project, and were thereby not in a position to make an informed view on the overall reasonableness of the proposed project.'* Our view is that NSPs should '*make the relevant supporting information and economic modelling publicly available. This should provide the opportunity for stakeholders to better assess whether the investment is in their long term interests for consumer funded projects.'* This highlights that modelling and analysis should be undertaken in a transparent manner so that stakeholders can gain confidence in the analysis used in asset replacement planning.

5.3 Assessment of likelihood of consequence

The likelihood of consequence is the probability that an asset failure will, if it occurs, result in a specific consequential outcome. For each event, the consequences of that event are selected, defined, evaluated, and a likelihood of that consequence occurring is estimated.

For each consequence, the likelihood of the consequence of the failure occurring is typically denoted as a percentage.

5.3.1 Determining critical input values for likelihood of consequence

The selection of critical input values for the likelihood of consequence should be adequately explained and justified, including with reference to costs incurred by the NSP and/or industry in supporting the estimate.

In Appendix B we have provided a comparison of critical input values drawn from recent revenue rests.[50]

> ***BOX 13 – Likelihood of consequence for major events***
>
> In a transmission system operating at 330kV and above, the loss of a protection system could have the potential for a significant system event due to the connected generation and power flows. Such an event has a very low probability, and is unlikely to be supported through a history of similar events.
>
> In calculating the likelihood of a system wide event, and the reliability impact of such an event, it is important to consider reasonable moderating factors to the calculation of the likelihood of consequence, such as:
>
> - Likelihood of duplicated system failure, given that the NER requires critical protection systems to be duplicated schemes;
> - Likelihood of a genuine fault occurring on the network, given that the fault event must be coincident with the unavailable of the duplicated schemes. This likelihood may be generated from historical records and observations;
> - Reduction in risk due to relay self-monitoring, where the NSP is alerted to a faulted state of state where the protection may not operate as intended. This allows time for investigation and repair and reduces the risk of mal-operation.
>
> When the aggregate impact of these factors is included, a sense-check can be gained by considering the extent to which the analysis reasonably reflects the NSP's current operating environment.

5.3.2 Consideration of additional moderating factors

Other factors that may further moderate the likelihood of consequence, or the cost of consequence, may include (but are not limited to):

- Hazard zone occupancy, related to likelihood of fatal injuries arising from explosive failure of asset, discharge from electricity (including electrical contact with a person), step or touch potential hazards, structural failures or failing equipment;

50 The values and sources are intended to provide guidance to NSPs and not to act as a definite list of values and sources. The onus is on the NSP to justify the selection of critical input values. Our view is that NSPs have not adequately justified critical input values in all cases.

- Bushfire zone type or proximity, related to likelihood of a significant bushfire arising from an electricity ignition source;
- Effect of controls, that act to reduce the likelihood or consequence of an event; and
- Outage times, related to duration of supply interruption arising from failure event (different to repair time / restoration to normal system operation).

> ***BOX 14 – Consideration of hazard occupancy***
>
> Where a safety risk is being assessed, it is necessary to properly define the risk that the 'failure' leads to the 'consequence'. A fatality does not necessarily result from every explosive failure, collapse of a tower, or from a conductor failing. When assessing the risk of such hazards, the risk needs to be moderated for example by the probability of a person being within a reasonable proximity of the hazard when the hazard is present. Within that hazard zone, there may be a further moderation as to the risk of any injury being fatal, and this may be further moderated by the effect of controls.
>
> In recent revenue determinations, we reflected the following conclusions regarding estimation of safety risk included in economic modelling of asset replacement planning:
>
> - It is necessary to account for the level of exposure to safety hazards, through a hazard occupancy rate (or similar factor or modelling), in order to reasonably quantify safety risk and forecast the prudent volume of asset replacement expenditure required to achieve the capex objectives.
> - The estimate of the hazard occupancy rate which should be used in safety risk calculations should be the rate estimated for normal operations. It is the risk assessed in the course of normal operations that justifies the need for asset replacement in the first instance.
>
> We consider that the safety risk should be evaluated with reference to such moderating factors so that it reasonably reflects the actual operating conditions of the business.

5.4 Assessment of cost of consequence

Cost of consequence is the monetised cost of the consequence arising from an event. For each event, the consequences of that event are identified, defined, and costs assigned.

5.4.1 Determination of critical input values for cost of consequence

The selection of critical input values for the cost of consequence should be adequately explained and justified, including with the provision of supporting evidence such as the costs incurred by the NSP and/or within the industry.

In Appendix B we have provided a comparison of critical input values drawn from recent revenue rests.[51]

5.4.2 Determination of assets – individual or fleet

Individual assets can, in most circumstances, be used as the focus for calculating the risk cost. In other cases, the assets may be aggregated to an asset fleet (e.g. a type of circuity breaker technology) or asset class (e.g. circuit breakers), or asset group (e.g. pole-top assets).

In addition, some of the underlying data may vary materially with voltage level, and this may present another asset grouping (e.g. 132kV circuit breakers).

Alternatively, there may be cases where an asset sub-group or sub-class may be more suitable (e.g. a line section). This is typically the case for transmission or distribution lines, where the underlying data varies along the length of the line (i.e. depending on construction type and asset condition, the failure rate, likelihood of consequence, and other factors).

5.4.3 Principles for selecting critical input data

When determining critical input data, we suggest following these principles:

- The NSP should use its own data (where practical) and experience to inform the estimation of the critical input values;
- Any information used from sources external to the NSP should align to the electricity supply industry, and preferably from a comparable Australia region, where possible;
- All sources of information should be referenced;
- All assumptions should be documented and adequately justified, including where the NSP has elected to adhere to, or deviate from, the stated sources of information;
- Reference should be made to known industry practice or related research to support estimation of critical input values, where possible; and
- There should be consistency in matching the cost of consequence with the likelihood of consequence, and the probability of failure.

51 The values and sources are intended to provide guidance to NSPs and not to act as a definite list of values and sources. The onus is on the NSP to justify the selection of critical input values. Our view is that NSPs have not adequately justified critical input values in all cases.

BOX 15 – Value of transparency

Providing increased transparency to understand the source of input assumptions and forecasting techniques will result in more robust forecasts which lead to more efficient investment and operational decisions.

In a recent revenue determination, we noted that provision of:

'…a risk analysis memorandum for each project primarily driven by risk mitigation which described the specific inputs and assumptions to the risk analysis as well as the quantified outcomes... enabled us to review the input assumptions applied in … risk cost estimating analysis, the outcomes of which were in turn applied in the economic assessment of project options.'

Source: AER, Draft decision: ElectraNet transmission determination 2018 to 2023, Attachment 6– Capital expenditure, October 2017, p. 51.

Furthermore, providing this level of transparency is likely to lead to more interest and options emerging from the market, which is likely to lead to lower cost solutions that are in the long term interest of consumers.

6 Specific applications of risk-cost

This section describes some specific applications of risk cost calculations for the purpose of establishing the service cost when making asset retirement or de-rating decisions.

6.1 Applying VCR to determine reliability consequence cost

The reliability consequence is typically expressed as unserved energy. As an interim measure, we consider that a default value for the cost of unserved energy can be based on AEMO's value of consumer reliability (VCR). Where the load served is significantly different from the assumptions in AEMO's published VCR values, then the use of appropriately evidenced alternative values may be more appropriate. However, under clause 8.12 (b) and (g) of the NER, the AER is required to review both the methodology for estimating VCR and the values of VCR. When these determinations are made, we intend that the amended methodology and amended values will apply.

6.1.1 Selection of the consequence value

The VCR estimates the value that consumers place on a reliable electricity supply, or the value that consumers place on avoiding service interruptions. VCR is often used as the consequence value associated with events with a reliability consequence.

AEMO has undertaken VCR studies of the NEM jurisdictions and published their findings. The VCR varies between consumer classes (types), and across time. AEMO's VCR estimates incorporate a time dimension and are typically designed to reflect the value of short-time duration outages (up to a few hours).

NSPs already use the VCR in probabilistic network planning. In a similar way, VCR can be used for asset replacement planning where the value the economic benefits (i.e. avoided unserved energy) can be compared with the cost of investment.

Whilst we provide a synopsis of the interpretation and the application of VCR values in asset replacement planning, we suggest NSPs refer the AEMO's VCR Application Guide (2014).

To apply the VCR to determine a reliability consequence cost, the following inputs must be determined:

- load at risk, taking account of any mitigating demand management, load control, load transfer, or other such arrangements;
- consumer mix affected; and
- duration of any supply outage event.

> ***BOX 15 – Application of VCR***
>
> For reliability related risk, the use of accepted 'industry' values of VCR is a reasonable assumption in most circumstances. The exception being where the load at risk is clearly not analogous to the 'typical' loads considered in these industry-wide averages.
>
> Where alternate VCR values are adopted, these must be supported with sufficient evidence to support their use over industry accepted values.

6.1.2 Determining the demand level

The NSP should nominate which demand forecasts it has relied upon for its asset replacement planning over the planning period, and how these relate to assumptions used for its augmentation planning and AEMO's published forecasts.

6.1.3 Determining the load at risk

In calculating the load at risk, or the impact of a failure event which leads to unserved energy, the NSP should consider:

- the load being carried by the asset, or segment of the network being studied;
- the actual redundancy available;[52]
- the likely duration of any supply interruption; and
- any arrangements available to transfer or manage the load interrupted or the duration of the interruption. For example, demand management arrangements, load control, load transfer capability, network automation, energy storage, or other such arrangements.

An assessment of the load duration curve for the relevant part of the network can be a useful guide for calculating the load at risk, considering minimum, average and maximum demand. The NSP should explain the basis for selecting the load at risk to ensure it reflects a reasonable estimate of the expected demand at the time of failure.

52 For example, if there is 100% redundancy for loss of an asset, then the energy not supplied would also be zero. However, there is typically a finite risk that one of the redundancy elements could be unavailable at the same time as the primary asset. In modelling supply outages, the actual supply configuration should be reasonably accounted for in estimating unserved energy.

BOX 16 – Use of Unavailability factor

A redundancy factor or unavailability factor can be applied to network configurations where the network design includes a level of spare capacity to ensure network and system security is maintained in the event of a network outage.

Application of this type of factor can be derived for a single network element, or across a population to provide an indication of an average unavailability rate for that asset type. In deriving such a rate, adequate validation and verification of the included data and assumptions must be undertaken to provide assurance that the outage times and typical replacement times when a critical transformer needs to be returned to service are reasonable, and not likely to bias the results.

For complex assets this can be derived through modelling of the power system to verify that an outage condition results in loss of supply.

As electricity networks are typically highly meshed, consideration of a redundancy or unavailability factor is important, as the loss of a single component is unlikely to result in loss of supply. However, there may be a circumstance where an asset is unavailable at a time when a failure may occur, or alternatively given the failure has occurred, another network element may become unavailable.

Application of a redundancy (or unavailability) factor as a moderating factor applied to the CoF provides a reasonable method of recognising the low likelihood of a consequence event that occurs only after the independent failure of two or more elements of the network.

Importantly, as soon as one component is restored, the consequence typically ceases to exist, or in a small number of circumstances a consequence of a lower magnitude may persist for a period of time. Transformer outages are examples of this scenario.

6.1.4 Determining the duration of risk event

We have observed that the duration of the supply interruption is often not well understood or applied to asset replacement planning and the application of the VCR. The VCR was developed for short duration events associated with maintaining security and reliability and was not intended for valuing sustained long-term outages. In sustained long-term outages VCR values may decrease as consumers make other arrangements to minimise the impact of the outage.

In relation to asset replacement planning, the applicable duration for unserved energy should be based on the average time within which the NSP should be able to restore supply, taking into account:

- Good industry practices, including:
    - robust contingency planning; and
    - comprehensive spares holdings in accessible locations.

- The mean time to restore supply (or partially restore supply to reduce the cost of consequence), including:
  - non-network solutions (such as by triggering curtailable load contracts);
  - emergency repairs (i.e. not replacement of assets);
  - network reconfiguration;
  - network automation schemes; and
  - early decision to replace the failed asset with spare.
- The impact on the load not supplied from progressive restoration; and
- The impact of alternative supply sources, such as temporary generation.

The options analysis should include any additional costs for restoring supplies such as connecting temporary generation or energy storage.

> ***BOX 17 – Moderation of low probability high consequence events***
>
> Consider the case in which failure of a parallel repairable component occurs while the first repairable component is in failure mode (i.e. having failed but not having been repaired). In this case a supply interruption will occur.
>
> The relevant annual risk cost is a function not only of the probability that any of the relevant components fail in a year, but also the (mean) time to repair for the failure mode. This is because supply is only interrupted if a second component fails during the 'repair' time of the first component.
>
> Importantly, where both components are failed, supply is restored when one of the two components are restored.
>
> Failure of a transformer in a two-transformer substation (transformers are operated in parallel) is an example of this situation. The loss of supply that results from the failure of both transformers could be large. However coincident failures have a very low probability of occurring. In other words, whilst the consequence may be high, the likelihood may be very low.
>
> When considering high consequences arising (typically) from multiple failure events and operational conditions (e.g. at peak load), the NSP should take into account the coincident unavailability of the assets and how this moderates the consequence. The time required to restore supply to customers, should a loss of supply event occur, rather than the time required to repair / replace the failed network element needs to be determined.

6.1.5 Demand-weighted locational VCRs

The building blocks for determining the VCR for a specific location and consumer mix are the discrete consumer groups for which AEMO has derived VCR values:[53]

- commercial;

53 AEMO, *VCR application guide: Final report*, December 2014, Tables 1-3, p. 4.

- industrial (non-direct connect consumers);
- agriculture; and
- direct connect consumers (for transmission level studies only).

A locational VCR can be calculated by weighting the VCR results using the composition of the consumer demand being served. The demand-weighting to use in calculating locational VCRs varies with:[54]

- The contribution of the consumer group to the maximum demand or annual or seasonal energy consumption;
- Whether the unserved energy was voluntary or involuntary, noting that:
- the results of AEMO's VCR review represent the value of involuntary loss of load; and
- voluntary responses would have a different, lower value;
- Whether the unserved energy is targeted[55] or untargeted.[56]

6.1.6 Consequence cost

The consequence cost for reliability related events can therefore be determined using the following simplified equation.

Consequence cost = Load at risk x Duration of event x VCR

Where the:

- *Load at risk x Duration of event is often termed 'Unserved Energy' and, where relevant, takes account of potential progressive restoration of the load; and*
- *VCR is as specific as possible to the mix of consumer types affected.*

The above approach can be refined by summing the consequence cost calculated for each consumer type affected.

6.1.7 Consideration of moderating factors

The NSP may consider that additional moderating factors may apply to the likelihood of the full consequence occurring. In the case of reliability and security risks, moderating factors may apply to the duration of an event, and/or the amount of load at risk. However, while possible, factors that moderate the cost of consequence are less likely to apply.

For example, where an asset failure results in the loss of supply to loads of a radial transmission line and local generation support is available, then the duration of the energy at risk is limited to the time required for the local generation option to restore supply (in part or whole). Any additional costs associated with this option would also need to be included in the analysis.

54 *Ibid,* p. 8

55 Pre-contingent load shedding or directed load shedding in a distribution network based on priority lists.

56 Major, sudden outages and likely to affect customer demand evenly across all customer groups.

In asset replacement planning, estimation of unserved energy should recognise that NSPs are typically able to restore some or all supply in a reasonable amount of time due to network redundancy, network automation, or emergency repair action. The duration is intended to reflect the time required to restore supply, not the time required to return the asset to normal service, or replace the asset,

Similar to the calculation of the load at risk, the duration of the event should be informed by the network's actual capability or by modelling the network's capability. Where this is not readily available, estimates should be provided that reflect operational practices. These estimates should be validated by NSP or industry experience.

> ***BOX 18 – Example - Radial 132kV transmission line***
>
> A conductor drop could result in an outage and loss of supply to customers (and incur associated costs). In the case of a radial line, the total load would be lost for a line outage valued at VCR for the duration of the repair time.
>
> Where the NSP has a network support service contract in place at the remote end of the transmission line, that arrangement can be used to support the load in the event of an outage.
>
> Typically, the network support service will also have a contracted availability. Assuming the network support service can supply the load for the duration of the line repair, the loss of supply will be limited to the duration required to commence supply, and supply would be limited to the period over which the network support service can operate. Consequently the relevant unserved energy, valued at VCR, should be determined taking account of these and any other relevant time limits.
>
> The network support service will incur a cost, and this should be included in costing the failure event.
>
> The provision of the network support service has the effect of limiting the consequence for this line event. In asset replacement planning the NSP should account for any networks support arrangements to provide a more accurate reflection of the operating environment in place and impact to consumers.

6.1.8 Applying non-network solutions to defer asset retirement

Application of demand management (DM) can be undertaken at a project level on a case-by-case basis for larger projects, or at a portfolio level for programs. These can collectively assist in deferring asset retirement or reduce the scope of any post retirement investment.

The NSP should undertake a cost benefit assessment to assess the economic efficiency of non-network solutions compared to network options over a reasonable modelling period. In undertaking this assessment, consideration should be given to the option value of deferring asset retirement, maintaining investment flexibility, or minimising / avoiding capacity stranding. Delaying or minimising network investment creates option value that may arise from new future solutions that better meet ongoing needs or service levels at that time. This might (for example) reflect the value of better knowledge of future service level requirements future demand, or of new lower-cost options.

For example, the cost benefit assessment may demonstrate that the non-network option is able to efficiently reduce the service cost by reducing the expected unserved energy and defer asset retirement.

In the presence of uncertainty about the future, it does not necessarily make sense to make all decisions concerning an option at the outset. Instead it may make economic sense to defer some decisions into the future, when better information is inevitably available about service level requirements, market conditions and available solutions.

6.2 Application to safety-related capex projects

NSPs are required to comply with safety-related regulations in their respective jurisdictions. Amongst other things, such regulation requires that an NSP take all reasonable steps to ensure that the design, construction, commissioning, operation, maintenance and decommissioning of its network (or any part of its network) is safe.

The Australian Competition Tribunal has recently reaffirmed our view that safety-related capex is subject to the same assessment under the capex criteria as any other claimed capex.[57] The need for a quantitative risk estimation methodology, that rigorously considers both the proposed methodology and quantitative inputs, applies no differently to selecting safety-related capex projects than it does for other capex project requirements.

6.2.1 Consideration of SFAIRP and ALARP principles

In making safety assessments, NSPs are subject to the application of the So Far As Is Reasonably Practicable (SFAIRP) principle. In applying the SFAIRP principle, NSPs should apply the As Low As Reasonably Practicable (ALARP) test to demonstrate the reasonably practicable requirement.[58]

The overarching principle is that extreme and high risks should be proactively reduced until the cost of doing so becomes grossly disproportionate to the benefits. Within an economic context, this test requires monetisation of safety risk, with an event causing a fatality being a typical test case. Good industry practice is to apply the value of statistical life (VSL) to monetise the risk associated with a fatality.

The common and relevant aspects of ALARP are that it requires an assessment of the response to an unacceptable hazard that it is reasonably practicable to implement. Determining what is reasonably practicable is achieved by undertaking an economic test for options in which risk is reduced to 'as low as reasonably practicable', by incurring expenditure up to the point at which the expenditure would be 'grossly disproportionate' to the benefit (risk reduction) achieved. That is, if it is not grossly disproportionately uneconomic to do so, then the source of the risk should be eliminated.

57 Re SA Power Networks [2016] ACompT 11 at [481].

58 A simplified illustration of the relationship of ALARP and SFAIRP can be found in the presentation *'ALARP vs SFAIRP (within the context of WHS legislation),'* presented by C.S. Wong, Chief Officer – Specialist Services, Chief Adviser – Electrical, WorkSafe SA, Wednesday 23 July 2014, https://www.engineersaustralia.org.au/sites/default/files/resource-files/2017-01/cs_wong_-_alarp_vs_sfairp_whs_legislation.pdf, accessed 21 August 2018.

Conversely, if it is not reasonably practicable (i.e. not economically justified, not technically possible, etc.) to eliminate the source of risk, then expenditure should be incurred to mitigate the risk to as 'as low as reasonably practicable.'

To demonstrate that the expenditure would be grossly disproportionate, it is common to apply disproportionality factors to the determination of risk cost to demonstrate that the requirements of ALARP have been met. These factors account for uncertainty in the variables involved in the analysis and represent the principle of prudent avoidance. Application of disproportionality may be achieved by:

- Applying the disproportionality factor to the calculation of the relevant consequence cost using the simplified risk cost formula; or
- Developing an additional ALARP test, where the disproportionality factor is applied to the relevant consequence costs.

The selection of disproportionality factors and the method by which these are applied varies. The factors may vary between workers and the public to acknowledge the systems and processes already in place to mitigate risk for trained persons when compared with the public.

6.2.2 Determining the consequence value

The value of statistical life (VSL) is an estimate of the financial value that society places on reducing the average number of deaths by one,[59] and is often used as the consequence value associated with events with a safety consequence.

There have been many studies performed globally to estimate VSL. The results of these studies vary by industry and geographic location. The Australian Government released a Guidance Note on VSL based in Australian Dollars in 2014.[60]

There are many assumptions in forming the VSL, and the guidance note from the Australian Government suggests performing a sensitivity analysis of the VSL as part of a cost benefit analysis. The sensitivity analysis should help confirm that the expenditure proposed on the basis of the ALARP test is justified for a range of VSL values and, if sensitivity analysis indicates that the decision is 'marginal' – either in favour or against the option being considered – then this should precipitate a more careful examination of assumptions involved.

Where the NSP chooses to apply additional scaling factors to the VSL, these must be adequately explained and justified to ensure that the resulting risk cost is not overstated.

6.2.3 Consideration of moderating factors

To apply VSL to determine a safety consequence cost, the following moderating factors must be evaluated:

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59 Australian Government, Department of the Prime Minister and Cabinet, Office of Best Practice Regulation, *Best Practice Regulation Guidance Note, value of Statistical Life*, December 2014.

60 *Ibid*.

- Likelihood that the failure mode may cause injury (for example, if the asset failure is explosive);
- Occupancy or exposure level to the hazard (for example, the proportion of time that a worker or member of the public is in reasonable proximity to the hazard);
- Likelihood that the consequence will be realised (for example, that the explosive failure causes injury or fatality); and
- Severity level of consequence (for example, fatality versus injury).

In all cases reasonable estimates should be used, and where practical supported by evidence, or justified with reference to industry values, or other reasonable sources to provide confidence in the assumptions and values used.

We consider it unrealistic to assume that an asset failure with the potential to cause a fatality will always result in a fatality. If applied in this way, it will over-estimate the cost of the safety risk and inflate the expenditure required to prudently manage the asset. For example, in the case of explosive failure of an asset such as a porcelain insulator, the probability that any one person is hit by a projectile (i.e. a porcelain shard) will vary with the hazard zone occupancy or exposure level. The higher the number of people in the hazard zone at any particular time, the higher the probability that any one of the people in the hazard zone will be hit by a projectile.

Some of the other factors that will influence whether a person in the hazard zone may be impacted by a projectile include: (i) the point of failure, and (ii) the location of the asset relative to other assets in the terminal station that may provide some shielding.

Furthermore, factors influencing the probability that a person(s) impacted by the projectile will suffer fatal injuries are likely to include: (i) the location of the impact on the person(s); and (ii) the size, weight and velocity of the projectile.

These factors combine to reduce the likelihood of a fatality arising from an explosive failure, relative to a ‘conservative’ assumption that all such failures will result in a fatality.

Similarly, for bushfire risk, the following factors should be determined:

- Likelihood that the a failure mode will lead to a fire start (i.e. the asset failure initiates a fire ignition source);
- Likelihood that the consequence will be realised (for example, whether the ignition source develops into significant bushfire is likely to be seasonal);
- Exposure level to the hazard (for example, the area may be sparsely populated, may not include significant commercial activity, involve mostly lower cost properties or holiday type accommodation, etc.); and
- Severity level of the consequence (for example, fatality versus injury, significant property loss versus minor property loss).

Also, existing controls should be accounted for in estimating the exposure of personnel and the public to the hazard in question. Accounting for such controls reduces the exposure to the hazardous event.

6.3 Application to high volume low value assets

Programs associated with high volume, low value assets (such as poles, conductors, insulators etc.) can comprise significant expenditure due to the large volume of individual assets involved. Due to the volume of assets and relatively low value of individual assets, modelling individual condition, failure and risk may be problematic or unrealistic.

However, these asset types can be modelled at an asset class level, whereby individual assets can be grouped together as a subpopulation in a way that the normal asset management processes can be applied. Similarly, inspection and condition-based assessment information can be gathered and used to characterise the subpopulation. In the absence of reliable information, other criteria such as common environmental factors, or age or may be applied to assist the condition assessment until such time as better information becomes available.

In the absence of reliable condition information on some assets, a number of techniques can be employed such as:

- assigning an age based on the ages of surrounding assets;
- correlating condition with the condition of adjacent assets; and
- applying degradation curves (wear-out curve) based on age, locational and environmental factors.

A health profile can therefore be established for a subpopulation, and failure models developed. Based on these models, risk cost analysis can be undertaken for the subpopulation, and the overall implications of the subpopulation performance on service cost assessed in making a decision to retire a proportion of the subpopulation. This analysis is very similar to the analysis involved in making a retirement decision for a single specific asset. Those retirement decisions are similarly based on risk assessments that set asset inspection standards. For example the decision to condemn a wooden pole is based on a “safe” thickness that takes into account the probability and consequences of failure compared to the cost of pole staking or replacement. The primary difference is however, that in the case asset populations the ‘asset’ becomes the subpopulation itself, and the parameters of the economic analysis are evaluated at the subpopulation level.

When considering the retirement of a proportion of an asset subpopulation, the options will include repair, refurbishment, or replacement of various volumes of the subpopulation asset type. The efficient option would be to retire that portion of the asset subpopulation that minimises the expected total cost of providing the service to the consumer at the required service levels.

In a similar way to considering the retirement of an individual asset, risk cost analysis is required as an input to the economic analysis of the service cost of the BAU counterfactual and the option(s).

6.4 Application to obsolescence

In considering technical obsolescence, the risks associated with end of technical life, and therefore the inability to maintain the required service levels are similar to modelling failure risks. In considering the end of life risk cost, due consideration to operational controls such as spares management, harvesting parts from failed / replaced units and extended warranties must be considered, and where possible included in the risk cost analysis.

Generally, obsolescence is a cost that increases as the scarcity of spares increases and/or a cost that increases as operation, maintenance and repair becomes increasingly difficult and therefore more costly. Obsolescence may also impact on repair time estimates and impact on other risk costs (e.g. unserved energy).

As for all risk cost analysis, it is critical to document and justify the assumptions made, as the basis for identifying and evaluating the asset retirement or de-rating decision and any subsequent investment decision.

6.5 Treatment of joint and conditional probability

When undertaking risk cost analysis, NSPs should ensure that any proposed risk assessment method includes treatment of joint and conditional probability (as appropriate). This is critical to getting reasonable and meaningfully results, and to ensuring that the risk cost is not overestimated.

The assessment of the likelihood of consequence may include cases where multiple contingent outages are assumed to occur. These events are more likely to be considered in transmission or sub-transmission circuits because of the extent of redundancy (i.e. N-1 coverage).

Limiting the discussion to the more usual cases in which two elements are unavailable (i.e. an N-2 event), two scenarios arise:

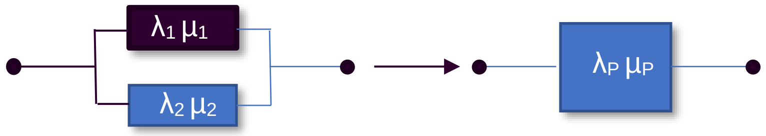
- The consequence (e.g. a supply outage) is a function of the time that two components are unavailable at the same time. As soon as one component is restored, supply is restored (e.g. where there are two parallel-connected transformers in a zone substation); and
- The consequence (e.g. a supply outage) is not necessarily related to the time for which the two (parallel) components remain in failure mode. Protection failure is an example of this situation.

In both situations, the relevant annual risk cost (e.g. from unserved energy) is a function of both the probability that any of the relevant components fail in a year and the time to repair those failures. This is because the relevant service interruption occurs only when a second component fails during the ‘repair’ time after a first component has already failed, or where both components fail together (i.e. a common mode failure).

There may be more than one combination of component outages which may result in the consequence. In such cases, the risk cost for the event is the aggregate of the risk cost calculation for each combination.

To illustrate the approach to determining the risk cost in such a scenario, we represent a two-component parallel system, one component of which must operate for ‘system success’ (e.g. to continue to supply power) and where the two components are repairable. The failure event caused by the failure of components 1 and 2 is generally known as an overlapping failure event.[61]

Figure 5: Representation of a two-component parallel system[62]



Where:

λ1 = failure rate of component 1	**μ1 = repair rate of component 2**
λ2 = failure rate of component 2	**μ2 = repair rate of component 2**
λP = the system failure rate	**μP = system repair rate**

If rP is the equivalent system mean time to repair, then

$$r_p = \frac{r1r2}{r1 + r2}$$

where:

- *r1 = mean time to repair component 1 = 1/μ1*
- *r2 = mean time to repair component 2 = 1/μ2*

The value rP represents the average period of time during which both components are concurrently out of service – that is it is the period when the two outages overlap. For this reason, rP is generally referred to as the overlapping repair or outage time of components 1 and 2.[63]

The failure rate of the single component equivalent to the two components in parallel is λp, which can be approximated as below.

$$\lambda p \simeq \lambda 1 \lambda 2 (r1 + r2)$$

If Up is the system unavailability rate, then:

$$Up = \lambda p \, rp = \lambda 1 \, \lambda 2 \, r1 \, r2$$

For example, in the case of a system failure leading to loss of supply, the annual risk cost for one combination of coincident unavailable components is the product of the system unavailability rate,[64] the load at risk, and the VCR. In this scenario, the system unavailability

61 R. Billinton & R.N. Allan (1992), *Reliability evaluation of engineering systems – Concepts and Techniques*, p.343.
62 *Ibid,* p. 344.
63 *Ibid*.
64 Converted to a per annum rate, as required.

is much lower than if the derivation is based on the assumption that the component outages do not overlap.[65]

65 The system unavailability would then be assumed to be the product of the two component unavailability rates.

7 Appendix A – Comparison of industry practices

We have compiled a summary of the approaches applied by three TNSPs[66] in recent revenue proposals. In preparing our summary, we have not sought to provide a detailed account of the methodology employed by each business or replicate existing information. Rather, we provide reference points that may be instructive to other NSPs in considering their own approach to implementing risk cost analysis.

The information provided is drawn from revenue proposals and supporting appendices provided to us as part of the revenue determination process and published on our website.

This information has been provided for information only, and we do not endorse any specific approach or method identified here. In presenting this information are we not suggesting these approaches or methods should be applied in any particular analysis nor are we agreeing with any of the approaches or methods used or their application.

66 AusNet Services, TransGrid and ElectraNet.

Table 5: Comparison of practices applied by NSPs

	AusNet Services[67]	TransGrid[68]	ElectraNet[69]
Assets included	Applied to major network asset classes, and terminal stations (groups of assets)	Applied to network and non-network asset classes	Applied to network asset classes only
Relationship to investment planning	Quantified risk assessment is applied for all risk-based asset replacement decisions	Quantified risk assessment considered for all risk-based asset replacement decisions and benefits-driven augmentation decisions.	Quantified risk assessment considered following decision to replace the asset. Options assessment is undertaken separate to risk-cost analysis, as a part of regional planning.
Applicable expenditure forecast	Replacement capex only	Benefits driven augmentation, replacement, security and compliance, non-network (IT) capex	Replacement capex only
Economic evaluation	Net Present Value (NPV) analysis of costs and benefits of options. Determines the risk cost per year avoided by implementing a replacement (or refurbishment) project as a benefit, or benefits from other sources. 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.	NPV analysis of costs and benefits of options. Determines the risk cost per year avoided by implementing a replacement (or refurbishment) project as a benefit, or benefits from other sources. 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.	NPV analysis of costs and benefits of options. Determines the risk cost per year avoided by implementing a replacement (or refurbishment) project as a benefit, or benefits from other sources.

67 Sourced from Ausnet Services regulatory proposal for the 2017-22 regulatory control period.
68 Sourced from TransGrid regulatory proposal for the 2018-23 regulatory control period.
69 Sourced from ElectraNet regulatory proposal for the 2018-23 regulatory control period.

Basis of assessment of timing	Options are compared using risk analysis. Project with positive NPV considered for inclusion into expenditure forecast. Optimised economic timing determined when the risk cost exceeds the annual levelised capital cost.	Assets considered to be in poor condition or end of life within the next 10 years considered for inclusion in risk analysis. Projects with positive NPV considered for inclusion into expenditure forecast.	Assets considered for replacement (from earlier options analysis) are included in risk analysis. Expenditure considered within the next or forthcoming regulatory period: • Base case • Investment in next regulatory period • Investment in the following regulatory period (next +1) Project with positive NPV considered for inclusion into expenditure forecast.
Simplified risk formula	For supply security, monetised supply risk cost per year[70] = (EAR1 x Pr (f) x VCR) + ….(EARn x Pr (f) x VCR) Where: • *EARn = Energy at risk (MWh)71* • *Pr (f) = probability of failure resulting in unavailability of plant* • *VCR = value of consumer reliability $/MWh)* • *n=risk event* For other risk areas (safety, plant	$\text{Monetised value of risk (\$)} = \sum_{K=0}^{Y} P(\alpha_K).(\$C_P.\beta_P + \$C_E.\beta_E + \$C_S.\beta_S +$ Where: • $P(\alpha K)$ *is the likelihood of failure attributable to failure mode K* • $\$CP$ *is the people safety consequence cost* • $\$CE$ *is the envirnoment consequence cost* • $\$CS$ *is the system impact consequence cost*	$\text{Risk cost per year (\$)} = (PoF_1\ x\ No_1\ x\ LoC_1 x\ CoF_1) + (PoF_2\ x\ No_2\ x\ LoC_2 x\ CoF_2) + \cdots (PoF_N\ x\ No_N\ x\ LoC_N x\ CoF_N)$ Where: • *PoFN = Probability of Failure N (%)* • *NoN = Number (length) of assets being replaced/refurbished* • *LoCN = Likelihood of Consequence N (%)* • *CoFN = Cost of Failure N ($)*

70 Not explicitly stated by Ausnet Services and therefore has been derived from Ausnet Services documentation.

71 Additional formulae are also provided for calculation of Expected Unserved Energy based on EAR calculated using 10%PoE and 50%PoE demand forecasts.

	damage, environment), monetised risk cost per year[72] = (PoF1 x No1 x LoC1 x CoF1) + ….(PoFn x Non x LoCn x CoFn) Where: • *PoFn = Probability of Failure (%)* • *Non = Number of assets* • *LoCn = Likelihood of Consequence n (%)* • *CoFn = Cost of Failure n ($)* • *n=risk consequence area*	• $\$CF$ is the financial consequence cost • βP is the likelihood of the people safety consequence occuring • βE is the likelihood of the environment consequence occuring • βS is the likelihood of the system impact consequence occuring	
Risk tool	Excel spreadsheet	• Adaptation of Investment Risk Tool provided by AMCL; and • Excel spreadsheet	Adaptation of Investment Risk Tool provided by AMCL
Probability of Failure assessment	Based on assessment of • Condition assessment of the asset, • Allocating a remaining life (remaining service potential) • Determine the Characteristic Life • Determine the asset's Conditional Age: • Determine the asset failure rate:	Network capex - Based on assessment of • Condition assessment of the asset, • Calculated remaining life • Weibull failure rate using actual failures and survival data • Checked against operational experience, and industry benchmarks (including Cigre) Non-network capex –based on assessment of	Based on • Condition assessment of the asset, and • Failure mode, and population failure data • Determine failure rate Results are calibrated based on operational experience only.

[72] Not explicitly stated by Ausnet Services and therefore has been derived from Ausnet Services documentation.

		replacement life	
Predictive probability of failure tools	2 parameter Weibull analysis, based on available failure data and survival data (for non-failure replacements). Developed using Availability Workbench (AWB)	2-factor and 3-factor Weibull analysis based on available failure data	Historical failure data
Verification and calibration of failure rates	Results are calibrated based on a single point average of AusNet Services historical asset failure and replacement data	Results are calibrated based on a number of representative historical asset failures and replacement data. Also, verified against operational experience, industry records and Cigre records	Verified against operational experience only
Likelihood of consequence factors	Range of values derived by TNSP	Range of values derived by TNSP	Range of values derived by TNSP
Cost of consequence	Range of values derived by TNSP, refer to discussion in Appendix B	Range of values derived by TNSP, refer to discussion in Appendix B	Range of values derived by TNSP, refer to discussion in Appendix B
Sensitivity analysis	Applied for discount rate, VCR, asset failure rate and demand growth scenarios.	Applied for selected value of cost of consequence, VSL, ALARP, VCR, load forecast, disproportionality factors, probability of failure	Applied for selected value of cost of consequence, for example VSL +/- 30%
Key consequence areas	Key consequence areas • Supply Security Risk; • Health and Safety Risk;	Key consequence areas • People safety; • Environment;	Key consequence areas • Electricity service interruption; • Bushfire;

	• Environmental Risk; and • Plant Collateral Damage Risk.	• System impact; • Financial; • Compliance; and • Reputation.	• Personal injury; • Repair cost; • Service obligation violation; and • Environmental.
Assessment of ALARP	Disproportionality factors incorporated into values of cost of consequence	Separate ALARP test applied, where disproportionality factors applied to risk cost components and compared with capital cost	Disproportionality factors incorporated into values of cost of consequence
Economic assessment	NPV Avoided risk cost modelled as a benefit	NPV Avoided risk cost modelled as a benefit	NPV Avoided risk cost modelled as a benefit
Economic analysis tool	AWB and Excel spreadsheet	Excel spreadsheet	Excel spreadsheet – Economic Assessment model
Options assessment	Options include: • Replace-upon-Failure; • Renewal on Risk; • Renewal by Asset Class; and • Renewal on a Bay-by-bay (or Scheme/Network).	Options limited to replacement or refurbishment, subject to asset class strategy and include: • Full replacement; • Partial or strategic replacement; and • Refurbishment.	Expenditure option already pre-determined prior to risk assessment methodology. Options limited to timing only.
Economic timing	Used risk cost versus annualised capital cost to determine timing	Economic timing limited to whether asset replacement decision was considered within next or following regulatory period.	The resulting NPVs for each case are compared and used as a guide to determine the most economic investment option and timing Economic timing limited to whether asset replacement decision was considered within next or following regulatory period.

Additional economic inputs	Inputs considered in assessments include: • Capital and operating costs of alternative options; • Reliability Benefits; • Market benefits; • Opex cost savings; • Risk reduction; • Alternate discount rate assumptions; and • Timing.	Inputs considered in assessments include: • Capital and operating costs of alternative options; • Reliability Benefits; • Opex cost savings; • Risk reduction; • Standard discount rate assumptions; and • Timing.	Inputs considered in assessments include: • Capital and operating costs of alternative options; • Reliability Benefits; • Opex cost savings; • Risk reduction; • Standard discount rate assumptions; and • Timing.

8 Appendix B – Comparison of critical input values

We have compiled a summary of the typical critical input values applied by three TNSPs[73] in recent revenue proposals.

The information provided is drawn from revenue proposals and supporting appendices provided to us as part of revenue determination processes and published on our website.

The values and sources are intended to provide guidance to NSPs and not to act as a definite list of values and sources to apply.

This information has been provided for information only, and we do not endorse any specific value or values given here. In presenting this information, we are not suggesting these values be applied to any specific analysis, nor are we agreeing with any of these values or to their application.

Table 6: Comparison of input values by NSPs

Critical input value	Approximate range of values applied	Source of values
Value of Consumer Reliability (VCR)	Based on mixed consumer use for each jurisdiction	AEMO VCR study, 2014 escalated to today's dollars
Value of Statistical Life (VSL)	The values applied by NSPs vary in the range of \$4m to \$10m.	VSL values are typically adopted from the advice provided by the Australian Government; [74] with CPI applied to index to a current year value. A range of additional reference sources are denoted, including: • AS5577; • AS7000; or • Own research and internal advice.
ALARP Disproportionality factor	The values applied by NSPs vary in the range of 1 to 10. Typically, separate values are used for industry workers and members of the public.	ALARP disproportionate factors are typically adopted based on advice stemming from the Health Safety Executive UK. [75] No specific reference is available from within Australia. Selection of the specific values is denoted based on additional NSP research and internal advice.

73 AusNet Services, TransGrid and ElectraNet.
74 Australian Government, *Best practice regulation guidance note: Value of statistical life*, December 2014.
75 Australian Government, *Best practice regulation guidance note: Value of statistical life*, December 2014.

Bushfire cost	The values applied by NSPs vary in the range of $10k to $400m.	Bushfire costs are typically developed by NSP research and internal advice to best reflect the individual operating conditions.
Environment costs	The values applied by NSPs vary in the range of $5k to $1m	Environment costs are typically developed by NSP research and internal advice to best reflect the individual operating conditions.
Regulatory compliance costs	The values applied by NSPs vary in the range of $5k to $10m.	Regulatory compliance costs are typically developed by NSP research and internal advice to best reflect the individual operating conditions.
Financial cost	The values applied by NSPs vary in the range of $5k to $5m.	Financial costs are dependent on the specific cost classification and are generally developed by NSP research and internal advice to best reflect the individual operating conditions.

The selection of critical input values should be adequately explained and justified, including with reference to costs incurred by the NSP and/or industry in supporting its argument.

9 Appendix C – Case examples

We have included two case examples based on the methodology applied in this Application Note and taking account of similar projects proposed by three TNSPs76 in recent revenue proposals.

The values and sources are intended to be illustrative only and not as a definitive list of values, nor of an endorsed approach. We do not endorse any specific value(s) or approach illustrated here, and in providing this illustration we not suggesting these values, methods or approaches be applied to any specific analysis or application.

Similarly, we have not provided detailed justification of the selection of the input values applied in the examples, whereas we would expect that the NSP would have access to sufficient information to present an adequate level of justification.

9.1 Example 1. Failure of 132kV transmission line

In this example, the (hypothetical) 132kV transmission line is of radial design, located in a regional area of Australia and is 100km in length. The line is comprised of 300 line segments of homogeneous design, installed in moderate climate, in flat terrain and the line and structures are considered to be in good condition.

The critical input values that have been applied to this analysis are listed in Table 7 below.

Table 7: Critical input value assumptions – Failure of 132kV line

Critical input values	Assumption
Value of Statistical Life (VSL)	$4.4m[77]
Serious injury consequence cost	25% of $4.4m
ALARP disproportionality factor	6 times for member of the public 3 times for industry worker
Value of Customer Reliability (VCR)	$39,000/MWh[78]
Financial consequence cost (low case)	$50,000[79]
Financial consequence cost (high case)	$1m[80]
Property damage (to third parties) from bushfire	$200,000[81]

76 AusNet Services, TransGrid and ElectraNet.
77 Based on the Australian best practice guideline value of $4.2m escalated to 2018 dollars.
78 Based on aggregate NEM VCR excluding direct connects, AEMO VCR study 2014.
79 Being the low case aggregate of various financial costs to the NSP.
80 Being the high case aggregate of various financial costs to the NSP.
81 Based on an assumed value of bushfire costs for this and comparable transmission lines based on design and geographical location.

The failure modes included for this example and a description of the probability of failure assumptions is provided in the table below. For this example, we have focussed on a single failure mode of conductor drop. We have not provided the detailed analysis from which the probability of failure has been derived; this would follow the steps outlined in this Application Note.

Table 8: Failure modes – Failure of 132kV line

Failure modes[82]	Probability of failure analysis
Conductor drop resulting from a conductor failure	Estimate of conductor drop failure rate for year 1 is 0.0005 per line segment (or span). The conductor drop failure rate is then estimated to increase over the next 20 years in line with a modelled probability of failure function. The failure rate for this line section for year 1 is therefore the product of the span failure rate and the number of spans, or 15%.
Unplanned (forced) outage resulting from a conductor failure	Estimate of forced outage is derived from the historical rate of high priority defects resulting in a forced outage to repair, that if not treated would result in conductor failure and an outage. The probability of failure may be estimated based on historical experience or predictive modelling. This value has not been used in this example, and therefore a value is not proposed.

The consequence analysis for the conductor drop resulting from a conductor failure is provided in Table 9 below.

Table 9: Consequence analysis – failure of 132kV line

Primary consequence	Consequence analysis
Personal injury	A conductor drop could result in personal injury (and incur associated costs) depending on the location of the failure. If a fatality or injury occurred the consequence costs may include components of: (i) compensation, (ii) litigation relating to prosecution, (iii) media coverage and (iv) investigation costs of the incident. The most significant consequence of a conductor drop is a fatality. We have included the consequence value as being the value of a statistical life multiplied by a disproportionality factor of 6, to account for a fatality of a member of the public. We have also included an aggregate financial cost associated with the high case. The likelihood of a conductor drop causing a fatality is assumed to be 0.1% based on the remote location of this line.
Bushfire	A conductor drop may create an ignition source that may lead to a bushfire (and incur associated costs). The bushfire may result in personal injury and financial loss. We have included a

82 Whilst not included in this example, additional failure modes may be considered for the earth wire failure, failure of the tower and or its components. The selection of failure modes will depend on the asset under consideration.

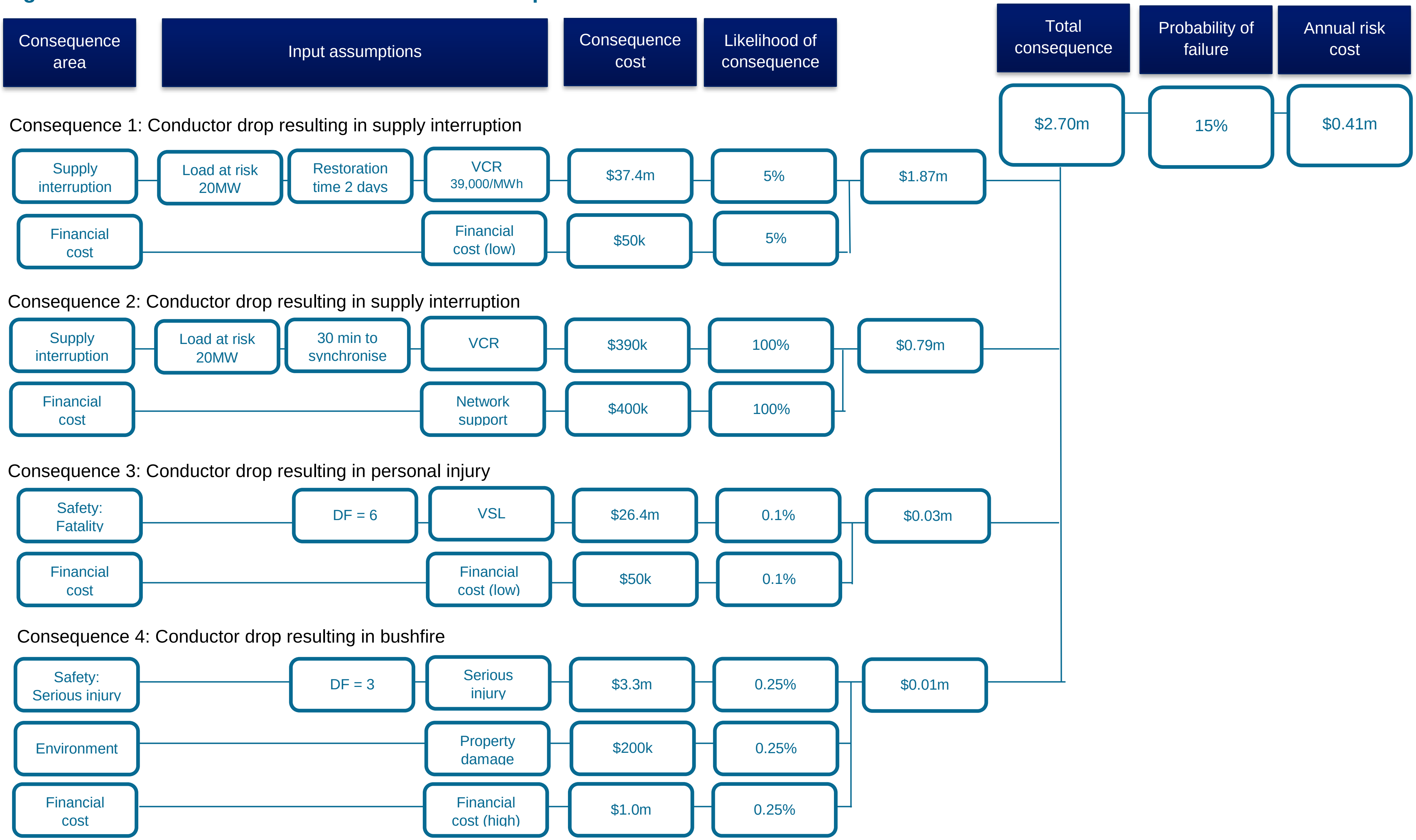
	personal injury cost as a 25% proportion of the value of a statistical life multiplied by a disproportionality factor of 3, to account for an industry worker involved in responding to the bushfire event. We have also included an aggregate financial cost associated with the low case. The likelihood of a conductor drop causing a bushfire is assumed to be 0.25%.
Electricity interruption	A conductor drop may result in an outage and loss of electricity supply to consumers (and incur associated costs). We assume that the average load of this line is 20MW, and as a radial line the total load would be lost for a line outage valued at VCR. The repair time for a 132kV conductor drop is assumed to be 2 days. We have also assumed that the NSP has a network support service contract in place at the remote end of the radial transmission line which can support the load for 2 days. The network support service has a contracted availability of 95%, which results in a likelihood of a conductor drop causing loss of electricity supply of 5% for a period of 2 days.
Network support cost	The network support service incurs a cost, which is assumed to be $200,000 per day based on market rates. In addition, the network support service comprising gas turbines requires a 30-minute start-up time to synchronise. During this time, the electricity supply is interrupted, and this is valued at VCR.

For this example, we have focussed on the primary consequence costs. The NSP may identify further costs. These might include (i) repair cost, (ii) market impact, (iii) other financial loss (including collateral damage, fire), or (iv) other third party damage costs.

In the diagram below, we illustrate how the annual risk cost can be calculated for Year 1 using the above assumptions. If the probability of failure increases with time, the function can be used in place of the year 1 value to generate an increasing risk cost.

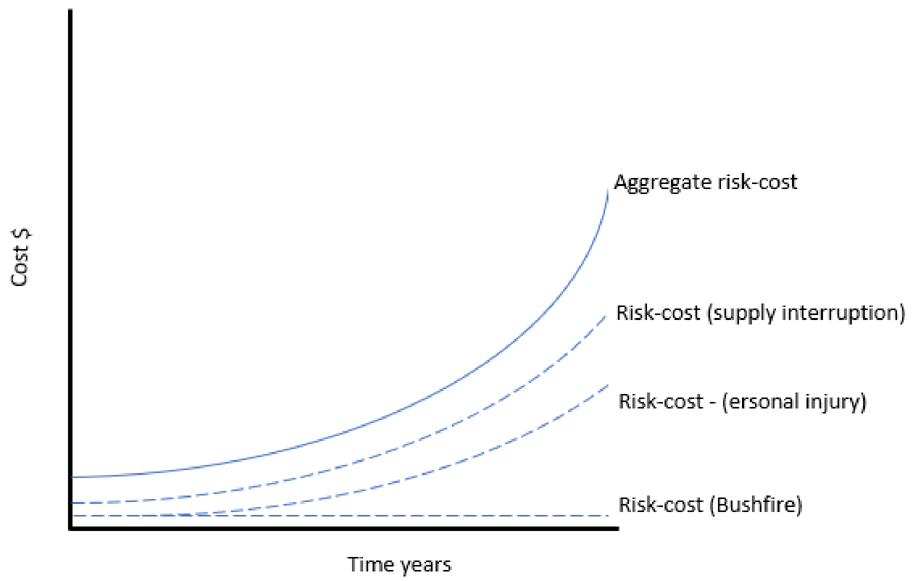
Similarly, this analysis can be applied to other failure modes, which when aggregated, provide a full picture of the total annual risk cost for this transmission line.

Figure 6:Risk cost for failure mode: Conductor drop from conductor failure



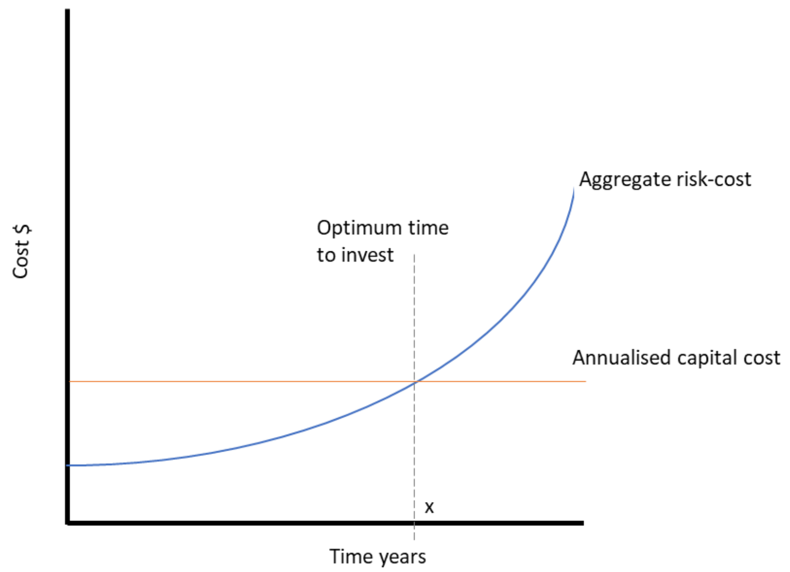
The annual risk cost for a conductor drop failure mode is calculated as $0.41m in year 1 and increasing in accordance with the increasing probability of failure function as illustrated in Figure 7 below.

Figure 7: Illustrative risk cost model – Failure of 132kV line



The options analysis should then identify capital costs for treatment options. These can be compared using NPV analysis, and the preferred option developed into an annualised capital cost. These can be mapped to the risk cost graph as in Figure 8 below, which indicates that line retirement with subsequent replacement is optimal at year x.

Figure 8: Illustrative model for optimal timing – Failure of 132kV line



The NPV analysis should include the avoided risk costs as a benefit and this analysis should demonstrate that the optimal timing for the project maximises the NPV. NSPs may consider additional benefits associated with operational efficiency, market benefits etc. All benefits should be robustly tested and justified.

Similarly, key input values should be subject to sensitivity analysis, including selection of appropriate discount rate(s) and other critical input values.

9.2 Example 2. Failure of 132kV CB

This example considers the retirement of a 132kV circuit breaker located in a 330/132kV terminal station. The critical input values are used in this analysis are listed in Table 10 below.

Table 10: Critical input value assumptions – Failure of 132kV CB

Critical input values	Assumption
Value of a Statistical life (VSL)	$4.4m[83]
Serious injury consequence cost	25% of $4.4m
ALARP disproportionality factor	6 times for member of the public 3 times for industry worker
Value of Customer Reliability (VCR)	$39,000/MWh[84]
Financial consequence cost (low case)	$50,000[85]
Financial consequence cost (high case)	$1m[86]
Property damage (to third parties) from bushfire	$200,000[87]

Based on the available failure data, a failure characteristic can be represented by mathematical relationship. For this example, we have used a 2-parameter Weibull distribution to reflect the probability of failure, and which reflects the historical performance for this NSP. The illustrative parameters are: beta (β) of 3 and characteristic life (η) of 45 years, which is represented in Figure 9.

83 Based on the Australian best practice guideline value of $4.2m escalated to 2018 dollars.

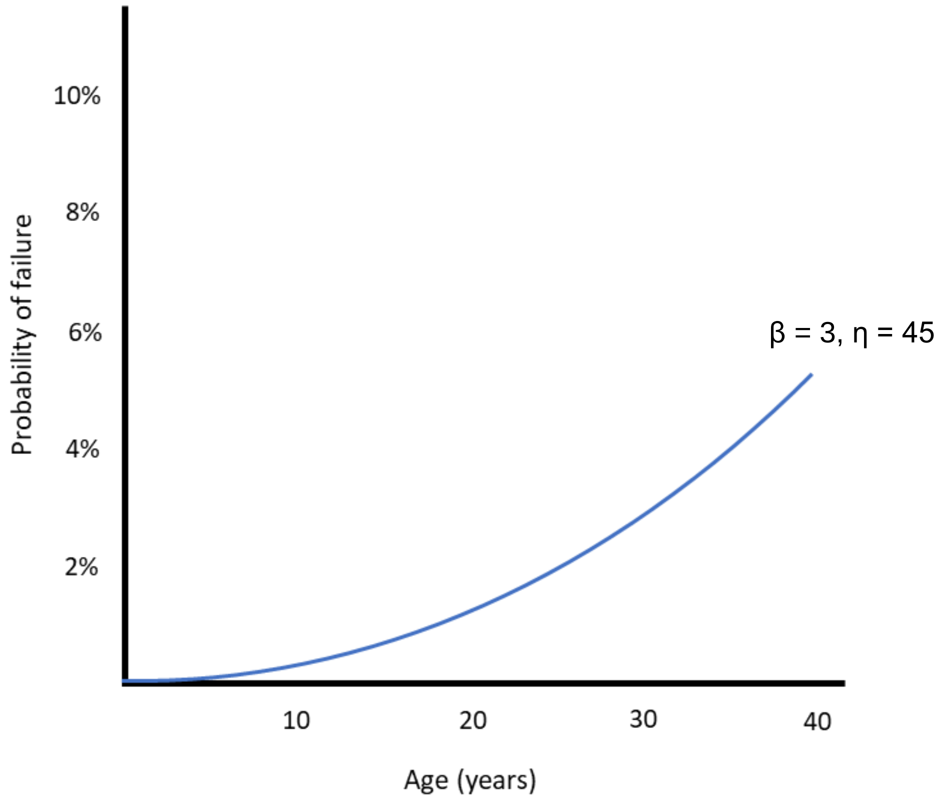
84 Based on aggregate NEM VCR excluding direct connects, AEMO VCR study 2014.

85 Being the aggregate of various financial costs to the NSP.

86 Being the aggregate of various financial costs to the NSP.

87 Based on an assumed value of bushfire costs for this and comparable transmission lines based on design and geographical location.

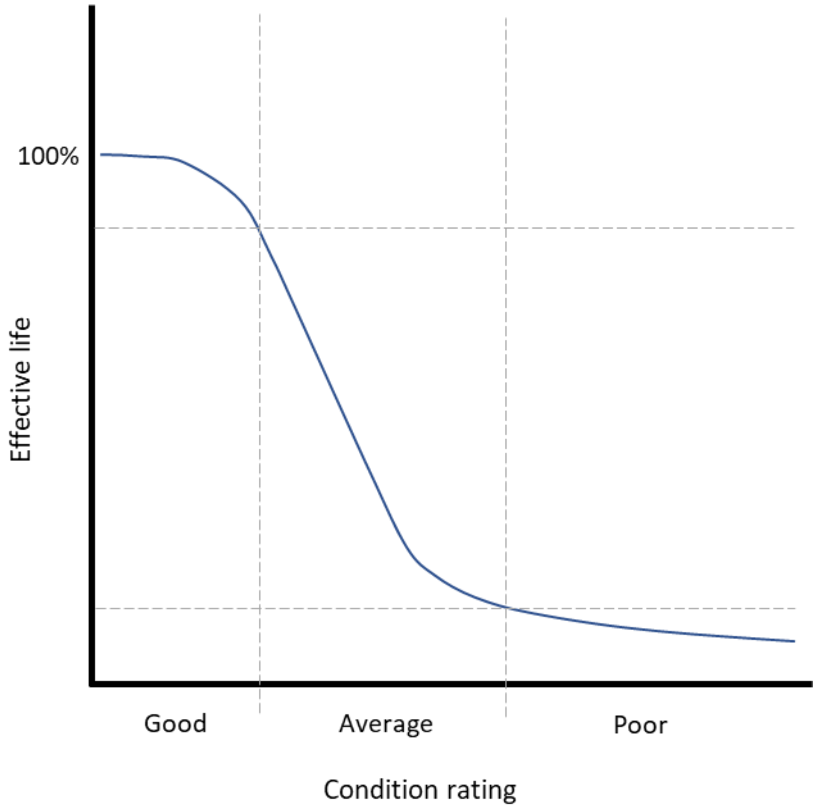
Figure 9: Illustrative probability of failure – Failure of 132kV Circuit Breaker



The age (or years of service) may need to be adjusted for the condition to allow for assets that are in better condition than others to exceed their design life (for example, due to lighter duty, improved maintenance, or benign environmental factors). This has been referred to as an effective or corrected age, or remaining life that is adjusted primarily based on the condition (health index) of the asset relative to the age of the population.

Where used, the typical relationship can be represented in Figure 10. Factors or parameters can be derived for a mathematical relationship to estimate the effective age of the population of assets. The NSP should ensure there is sufficient data available to have confidence in the relationship between effective age and condition, and that this data has been adequately verified from operational experience.

Figure 10: Illustrative relationship of effective age to condition – Failure of 132kV Circuit Breaker



Using the effective age, the probability of failure can therefore be derived for an asset at any year.

The consequence analysis for the circuit breaker failure is provided in Table 11 below.

Table 11: Failure mode analysis – Failure of 132kV Circuit Breaker

Primary consequence	Consequence analysis
Personal injury	A circuit breaker failure could result in personal injury (and incur associated costs) depending on the probability that the failure was explosive in nature, the proximity of a person to the failure, and the probability of the extent of any injuries that are sustained. If a fatality or injury occurred, the consequence costs may include components of: (i) compensation, (ii) litigation relating to prosecution, (iii) media coverage and (iv) investigation costs of the incident. We have included the consequence value as being the value of a statistical life multiplied by a disproportionality factor of 3, to account for an industry worker. We have also included an aggregate financial cost associated with the high case. The most significant consequence of an explosive circuit breaker failure is a fatality. There are three main factors that are considered in the analysis that may cause injury: • The incidence of circuit breaker failures that are explosive represents a smaller proportion of failures. NSPs should seek evidence to justify the selection of a

	suitable figure that reflects the relationship between failures and explosive failures for the asset class and operating conditions being studied. In this example, we have assumed that 25% of circuit breaker failures are explosive in nature. • The second factor is the proximity of the person to the explosive failure event, which is likely to vary between sites. NSPs have used the concept of Hazard Zone Occupancy, as a means to determine when a worker is likely to be present in the hazard zone where an explosive failure could cause harm. In this example, we have assumed that a worker is likely to be in the hazard zone for 15% of the time, in any one year. • The third factor is the probability of the extent of the injuries, which are likely to vary between sites and between NSPs due to operating practice differences. Considerations such as physical barriers, operational controls, and Personal Protective Equipment all act to potentially limit (but not remove) the probability of injuries being sustained from explosive failure. In this example, we have assumed that the design of the site and operational controls provide limited further risk mitigation, and therefore include a factor of 90%.
Electricity interruption	A circuit breaker failure could result in an outage and loss of supply to consumers (and incur associated costs). The calculation of the average load and likely time required to restore supply is dependent on the design and configuration of the network, at the time the load is present. NSPs should give consideration to the level of redundancy available in the network and the likely outage that may result. Often, the failure scenarios being tested are likely to align with N-1 events which will have a correspondingly lower likelihood of consequence occurring. In this example, we have assumed that the load lost as a result of circuit breaker failure is 20MW, due to the network design and configuration of the connected substation. This value is likely to vary between circuit breakers, across substations, and for different voltage levels. Similarly, whilst the repair time is estimated to be 5 days, in this example we have assumed an outage time of 60 minutes for supply interruption, after which electricity supply is restored to consumers through network switching. The NSP could also calculate the risk cost associated with the loss of supply for multiple contingencies (e.g. coincident failure of a second circuit breaker in a parallel circuit), however this is not included in this example. In such a case the NSP should use appropriate likelihood estimates for such an event.

For this example, we have focussed on the primary consequence costs. The NSP may identify further costs. These might include (i) repair cost, (ii) market impact, (iii) other financial loss (including collateral damage, fire), or (iv) other third party damage costs.

Table 12 below summarises potential options to be considered in the analysis. Planning analysis is assumed to have confirmed that the substation and circuit breaker have an enduring purpose.

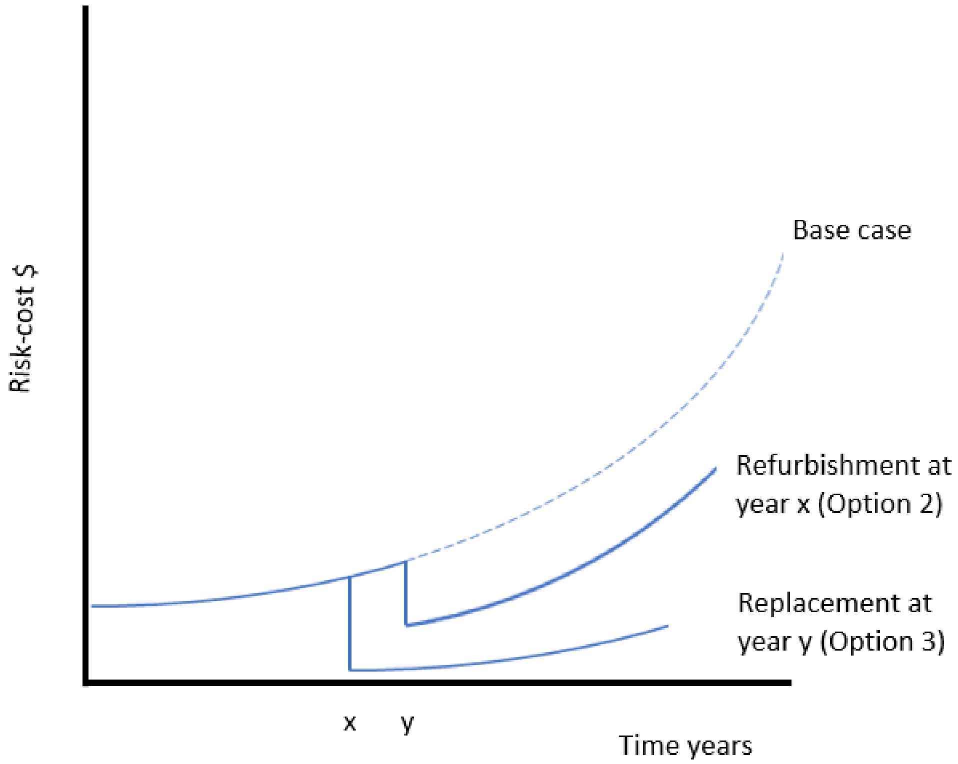
In the case of an embedded asset such as a circuit breaker there is unlikely to be a non-network option that could mitigate the risk cost. However, for other asset classes, this may not be the case.

Table 12: Options to be considered– Failure of 132kV Circuit Breaker

Option	Elaboration
Base case	This is the counterfactual and represents the current BAU costs that are likely to be incurred by the NSP. The Base case often has an increasing risk cost function attributed to it.
Option 1: Operating strategy and operational controls	In this option, the NSP may determine that an increased level of maintenance and/or additional operating controls may be sufficient to mitigate the identified risk such that any major expenditure can be deferred.
Option 2: Refurbishment	In this option, the NSP may determine that the circuit breaker is a candidate for refurbishment to extend its useful life.
Option 3: Replacement (like for like)	In this option, the NSP considers the case where the circuit breaker is replaced with a modern equivalent asset of comparable design and function, noting that this is likely to reflect an increase in functionality compared with an asset installed decades early.
Option 4: Prioritised / staged replacement (like for like)	In this option the NSP may prioritise replacements that deliver the highest risk reduction and therefore the highest benefits to consumers. This option is particularly relevant when considering a population or subpopulation of assets (i.e. the retirement of a portion of an asset fleet).
Option 5: Packaged replacement	In this option, the NSP may consider where the treatment of a group of assets is packaged together. For example CTs and CBs with DTCB, replace multiple protection devices with new scheme.

We have illustrated the potential impact to the risk cost in Figure 11, which when used in the comparative analysis will reflect a different benefits stream between the options. Figure 11 illustrates the base case and two of the five options only, for simplicity.

Figure 11: Illustrative difference in risk-costs – Failure of 132kV Circuit Breaker



Similar to Example 1, the annual risk cost can be calculated for year 1 using the above assumptions, and a risk cost time-based relationship developed for each assessment option. This is shown diagrammatically below.

The assessment of the options would typically apply NPV analysis, with appropriate sensitivity studies of key input parameters as discussed in this Application Note.

Figure 12: Risk cost for 132kV Circuit Breaker failure