31 January 2023

Attachment 5.4.f: CBA approach for major projects

Ausgrid's 2024-29 Regulatory Proposal

Empowering communities for a resilient, affordable and net-zero future.

Ausgrid

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1 Introduction

1.1 Purpose

In developing our investment plan, Ausgrid focuses on ensuring that our plans represent a robust justification and provide benefits to our customers and all our stakeholders. In order to help us make these decisions, we use Cost Benefit Analysis (**CBA**) assessments to thoroughly analyse and make decisions on investment requirements.

The purpose of this document is to provide an overview of the application of the principles set out in the overarching **Attachment 5.3.d - Principles of Cost Benefit Analysis** to the cost benefit analysis methodology and relevant assumptions made in the analysis of major project investments.

In essence, the methodology presented in this document is applied to the following major project categories.

1. Sub-transmission feeder projects
2. Switchgear replacement projects
3. New substation development projects
4. Sub-transmission network augmentation projects

1.2 Introduction

Ausgrid has been applying probabilistic planning framework for major equipment investments after the withdrawal of Distribution License Conditions in 2014.

The primary premise of probabilistic planning approach involves estimating the probability of an equipment outage and determining the amount of energy which would be interrupted as a result. A value is placed on this failure by multiplying the amount of lost energy by the Value of Customer Reliability (**VCR**) as discussed in Section 3.8.1.

This value of unserved energy together with other risks is included in the cost benefit analysis to justify a project – both to determine the optimal project solution to address a need and to establish the appropriate date to implement the project.

The structure of this document is as set out below:

Chapter 1 provides an introduction of Ausgrid's planning process and the requirement of applying the probabilistic planning framework to investment requirement.

Chapter 2 defines the methodology of CBA and the metrics the projects can be justified, and the initial ranking of projects can be established. It also discusses about the adjustment of timing and initial ranking based on scenario analysis and optimization.

Chapter 3 details the input data used, and any assumptions made in the CBA.

Chapter 4 focuses on more technical analysis on how the risks and benefits quantification would be done.

Chapter 5 provides a brief account of CBA models developed by Ausgrid.

1.3 Regulatory requirement

The Australian Energy Regulator (**AER**) Regulatory Test and Chapter 5 of the NER mandate a probabilistic planning approach to network investment decisions.

The Regulatory Test also specifies the assessment methodology to be used.

"The purpose of the regulatory investment test for distribution is to identify the credible option that maximizes the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity market (the preferred option). For the avoidance of doubt, a preferred option may, in the relevant circumstances, have a negative net economic benefit (that is, a net economic cost) where the identified need is for reliability corrective action."

"The regulatory investment test for distribution must be based on a cost-benefit analysis that must include an assessment of reasonable scenarios of future supply and demand; …"

"The regulatory investment test for transmission must be based on a cost-benefit analysis that is to include an assessment of reasonable scenarios of future supply and demand if each credible option were implemented compared to the situation where no option is implemented; …"

1.4 Probabilistic planning criteria

1.4.1 Transmission licence conditions

The Transmission license condition defines the level of redundancy required at each bulk supply point, with allowance to cater for some expected unserved energy. In general, at each bulk supply point, a minimum amount of load must be able to be supplied following the outage of a single transmission system element.

In the case of the inner Sydney Metropolitan Area, the five Inner Sydney bulk supply points (Beaconsfield West, Haymarket, Rookwood Rd, Sydney North and Sydney South) would be regarded as a single "group" acknowledging that the standard can only be achieved if TransGrid's transmission network and Ausgrid's supporting sub-transmission network are considered as a single integrated network.

For Sydney Inner Metropolitan bulk supply points, TransGrid and Ausgrid must co-operate to ensure that

a. A non-zero amount of load must be supplied following the outage of a single system element (includes a single 132kV feeder, 330kV feeder or 330kV/132kV transformer)

b. A non-zero amount of load must be supplied following the simultaneous outage of a single 330kV cable and any 132kV feeder or 330/132kV transformer

c. The expected unserved energy for any bulk supply point does not exceed 0.6 minutes per year at average demand.

TransGrid and Ausgrid are jointly required to comply with these requirements unless an IPART approved forward plan submitted by TransGrid and Ausgrid is in place to address any non-compliance issues and can be implemented within the nominated time frame.

Any plan submitted in this way will contain an analysis of the CBA in view of maximising the net economic benefit.

1.4.2 Distribution licence conditions

Ausgrid must maintain reliability levels of SAIDI and SAIFI below minimum thresholds.

SAIDI the sum of the durations of each sustained customer interruption (measured in minutes) in a financial year divided by the total number of customers.

SAIFI the total number of sustained customer interruptions in a financial year divided by the number of customers.

The SAIDI and SAIFI standards are defined for four feeder types and for individual high voltage distribution feeders. In each case, different standards are defined for different high voltage distribution feeders.

- Sydney CBD

- Urban
- Short rural
- Long rural

In addition, the Customer Service Standards define the maximum duration and the maximum number of interruptions to a customer's premises in a financial year with separate targets for customers in metropolitan and non-metropolitan areas.

The licence provides for Ausgrid to make certain payments to customers if the number and duration of interruptions in a financial year exceeds the specified limits.

Ausgrid is required to investigate the causes for any high voltage distribution feeder exceeding the individual feeder standards and take steps to improve the performance of the network to comply with the licence conditions.

1.5 Planning process

The purpose of the probabilistic planning process is:

1. To provide a basis for comparing investment options which would determine the most preferable investment option, whilst maximising the net economic benefit.

2. To determine if the project is a sound investment and to determine the most beneficial economic timing of the investment.

With the major projects, two planning approaches are used.

- Capacity planning – to determine capacity shortfalls
- Replacement planning – condition of the equipment

The above two planning approaches are being investigated in the combination of two planning processes outlined below.

1.5.1 Area planning

For the purposes of planning augmentations to the sub-transmission network, Ausgrid has divided its franchise area into 25 geographic '*Areas'* and generates a subtransmission *'Area Plan'* for each geographic *'Area'*.

The requirements of the Ausgrid *transmission/dual function network* that links TransGrid's bulk supply points to Ausgrid's distribution network are considered based on the broader Sydney Inner Metropolitan, Central Coast and Hunter regions to create three *'Transmission Area Plans'*. Each of these transmission regions encompasses multiple sub-transmission '*Areas'*.

Each Area Plan is revised on need basis. This process involves investigations into the needs, constraints and possible strategic solutions for that area which realistically have the potential to be addressed by investments in the transmission or sub-transmission network. It is designed to capture all of the drivers relating to the area and encompasses a ground up review of all credible strategies for meeting the network needs in that area. Following this process, the area plan defines a suite of projects that form the *preferred strategy* for that geographic area.

1.5.2 Annual capital review process

Ausgrid reviews the major projects portfolio every year due to the dynamic nature of new information available, especially the demand forecast. Each year, given the availability of new demand forecast, a suit of projects is reviewed to determine if the proposed dates of all the projects included in the plan are still appropriate and to initiate any necessary changes to the investment decision.

This review involves running the appropriate planning models for the already identified preferred strategies with the latest data. Given the models created during the Area Planning process already incorporate all the parameters required for probabilistic planning, the annual assessment is generally less intensive compared to the assessment undertaken during area planning stage.

1.6 Probabilistic planning tools

Ausgrid has developed four (4) tools in assisting the probabilistic planning process

11kV Switchgear to determine the optimal replacement date for 11kV busbars and associated switchgear in zone substations

33kV-132kV Switchgear to determine the optimal replacement date for 33kV-132kV busbars and associated switchgear

Zone Capacity to determine the optimal date to replace or augment Zone Substation transformer capacity

Sub-transmission Feeder Capacity - a more general model to determine the amount of unserved energy based on probable outages of various critical items of equipment.

Each of these tools is described in this document together with the rationale underpinning their development.

For each of the tools, separate work instructions/example use cases have been prepared which are used to guide staff in their use.

1.7 Related documents

Attachment #	Document
5.1	Proposed capex
5.2.a	Network Strategy
5.2.c	Customer Value Framework
5.3.d	Principles of Cost Benefit Analysis
5.4.b	Major Projects - 11kV Switchgear Replacement
5.4.c	Major Projects - Sub-transmission Cable Replacement
5.4.d	Major Projects – Other Replacement
5.6.c	Major Projects – Augex and Connections

1.8 Acronyms and abbreviations

AER	Australian Energy Regulator
AEMO	Australian Energy Market Operator
BSP	Bulk Supply Point
CBA	Cost Benefit Analysis
DUOS	Distribution Use of System
EPA	Environmental Protection Authority
EUE	Expected Unserved Energy
IR	Insulation Resistance
MTTR	Mean Time to Repair
NER	National Electricity Rules
PIP	Project Investment Portfolio
POE	Probability of Exceedance
SAIDI	System Average Interruption Duration Index
SAIFI	Service Average Interruption Frequency Index
STPIS	Service Target Performance Incentive Scheme
STS	Sub-transmission Substation
STSS	Sub-transmission Switching Station
TUOS	Transmission Use of System
VCR	Value of Customer Reliability

2 Cost-benefit Analysis Methodology

2.1 Overview of probabilistic planning framework

The essence of a Cost Benefit Analysis (CBA) is weighing up costs and benefits by comparing options to determine the solution that best addresses the business needs and mitigates risks, whilst maximising the net economic benefit. The role of CBA in decision making is to facilitate identifying the most prudent and efficient investment to address the problem. The decision-making process which applies to major projects can be broken down into a number of stages as illustrated in the following diagram.

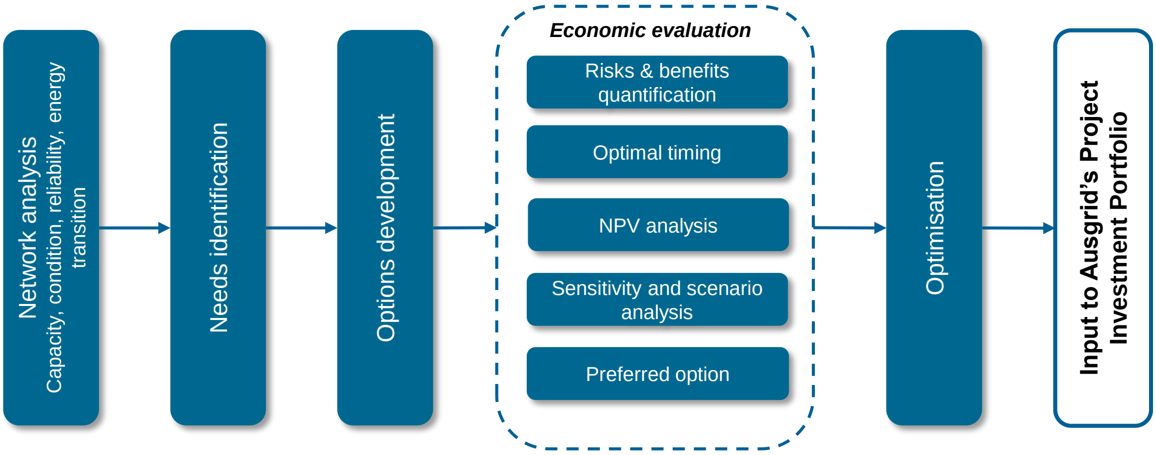

Figure 2-1 Simplified decision-making process

The first three steps are generally the planning phase of the decision-making process, also the preparatory phase of the CBA. The core of the CBA is the quantification of risks and benefits and NPV analysis. Each of the above stages are briefly described in following sections.

2.2 Network analysis and needs identification

The performance of Ausgrid's electricity network is governed by various performance standards including NER requirements and Australian standards. The status of the network is evaluated to identify any deviations from these performance requirements which are often referred to as "network constraints". Ausgrid's planning process, as described in Section 1.5, is well-developed and capable of analysing and identifying network constraints which may prevent us from supplying the customer in a safe and reliable manner. For this purpose, Ausgrid uses various analysis techniques including:

- Power flow assessment;
- Fault level assessment;
- Equipment condition assessment; and
- Supply quality assessment.

2.3 Options development

One of the important aspects of this process is the identification of various solution options to the network constraint identified. A holistic approach is considered by combining multiple constraints in order to find any combined solutions, which will generally be investigated in detail during the detailed area planning stage. An essential component at this stage is the development of 'base case' which is used to benchmark all the options identified. The common baseline is the "do nothing" option which gives a description of what will occur should the status quo maintain without any future investments.

Alongside the evaluation of the base case, alternative options are developed; the following options are being considered in every assessment as a minimum requirement. Where possible, opportunities for staging of the project are investigated and included in the option analysis.

- Demand management
- Decommissioning the assets without replacement
- Like-for-like replacement

At this stage, a careful consideration is given to non-network solutions such as demand management options and policy changes where applicable.

2.4 Risks and benefits quantification

A key element of Ausgrid's cost benefit analysis is the quantification of the consequences to customers, staff and/or the community of not acting. These are expressed in the form of a number of risks.

Risks can be quantified using probability distribution functions developed from historic asset performance, load data and network configuration. In the analysis, reduction of risk is considered a benefit to the market (including both Ausgrid and its customers), and the risk is generally computed as:

$$Risk = Probability \times Consequence$$

Probability of the event occurrence is derived from the probability distribution curve related to the asset, The consequence of the event occurrence is calculated in terms of the financial or economic impact, measured in dollars.

Ausgrid uses the following broad benefits categories in the cost benefit analysis. These fundamentally relate to the reduction of negative impacts to customers and the community:

- Expected Unserved Energy (EUE);
- Safety risk reduction;
- Environmental risk reduction;
- Financial risk reduction; and
- Other risks due to emerging issues such as supply quality risks, DER curtailment etc.

Attachment 5.2.c - Customer Value Framework sets out these metrics in more detail.

Different risks may be applicable to different types of equipment or parts of the network to a greater or lesser degree and therefore have differing levels of impact in corresponding CBA assessments.

Refer to Section 3 for details on input data used.

2.5 Optimal timing

The timing of projects is chosen to maximise the net economic benefit to all stakeholders. This is done by considering the potential timing of the proposed project cash flows and monetised benefits. When the benefits of a particular project outweigh the possible savings from deferring capital expenditure, and those benefits are forecast to continue, the project is said to be "needed" at that time.

The project costs for all options are calculated based on constant dollars (no time variation in value), and to compare the costs with benefits, one year deferral of the project is calculated as below equation. The total benefits are compared with the one-year deferral benefit to trigger the investment.

$$One\ year\ deferral\ benefit = \frac{rY}{1+r} \quad (1)$$

Where:

Y is the initial project cost

r is the discount rate

The below graph shows an output of sample cost-benefit analysis carried out for an 11kV switchgear replacement project. As can be seen, the crossover point where the annualised benefit exceeds the benefit of deferring the project by one year is taken as the trigger for the project to be completed, that is known as the network need date. In the example shown, the need date is year 2030, thus the project would need to be completed by the end of year 2029. Generally, the commencement date of a major project is four to five years ahead of the trigger year to allow for project development and construction lead times.

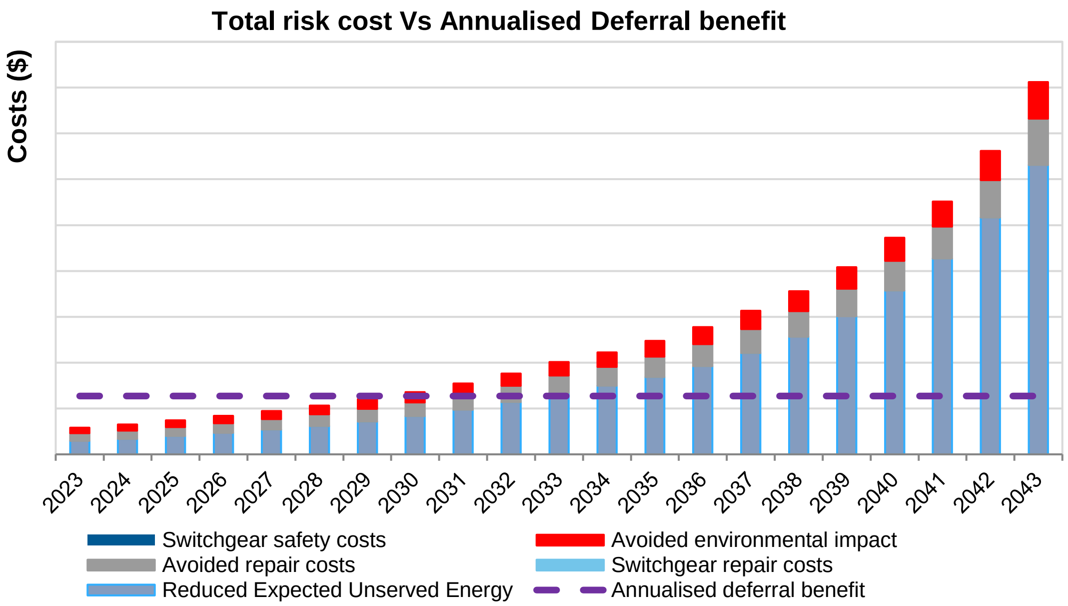

Figure 2-2 Need Date Assessment

2.6 NPV analysis

Whilst the optimal timing of each option is determined in accordance with the above criteria, it does not give an indication whether the maximum and positive benefit is presented over the life of the asset or over the planning horizon. The NPV analysis of each option is performed to identify as to whether it provides a positive market benefit.

Where projects involve the installation of network assets with nominal lives in excess of the planning window of twenty years, a terminal value may be used in the NPV calculation to account for benefits beyond the planning window. Because forecasts beyond the twenty-year planning window are uncertain, the terminal value is calculated by depreciating the project capital cost using straight line depreciation. Some projects that are said to be needed towards the end of the planning window may be sensitive to variation in the terminal value. In these cases, it is important to reassess the need each year so that a greater proportion of the benefits are based on explicit forecasts.

The net economic benefit of each option is calculated as illustrated in the graph below.

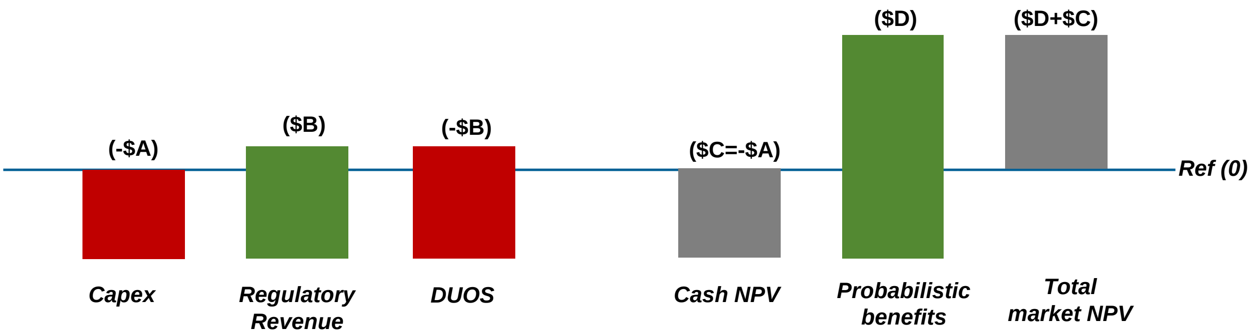

Figure 2-3 NPV Analysis for Options Comparison (sample data)

In essence, the total market benefit is calculated as below.

$$Total\ market\ NPV = |Probabilistic\ benefits| - |Cash\ NPV|$$

2.7 Sensitivity analysis

Sensitivity analysis is undertaken in order to gain an understanding of the investment decision by changing input parameters given in the baseline definition. The assumptions that are subject to the highest degree of uncertainty have been selected for inclusion in the sensitivity analysis.

In general, the following input parameters (predetermined low, base and high values) are included in the analysis.

Table 2-1: Sensitivity Analysis

Parameter
Value of Customer Reliability
Discount Rate
Project Cost
Load Forecast

The sensitivity analysis gives a range of dates (band) to be selected as the trigger year, as illustrated in the figure below. A careful consideration of the risks associated with the equipment and the considerations outlined in Section 2.10 are undertaken in order to select the optimum need date.

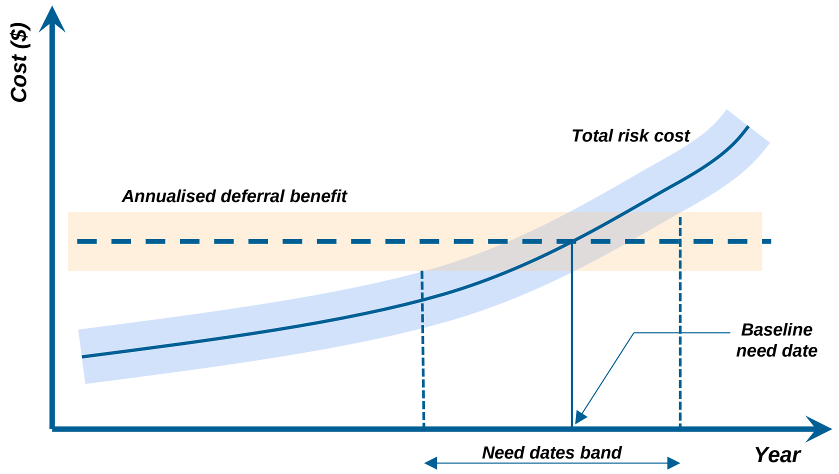

Figure 2-4 Illustration of need dates band

2.8 Scenario analysis

The purpose of the scenario analysis is to test the robustness of investment options for future uncertainties; in particular the variability demand forecasts. To this end, Ausgrid has developed four scenario forecasts to be in line with AEMO forecasts. They are:

1. Slow change
2. Progressive change
3. Step change
4. Strong electrification

For each potential investment option, the costs and benefits are estimated with four different scenario forecasts and the corresponding NPV is determined. Expected NPV for each option is calculated using following criteria to determine the option which would provide the highest expected NPV.

1. Equal scenario probability (25% chance)
2. Unequal scenario probability (giving more weight to some scenarios)

It should be noted that the scenario analysis requires additional rigorous data analysis, thus it will be carried out only for certain more complex investment options.

2.9 Preferred option

The aim of this step is to identify and agree on a preferred option that best addresses the network issue and maximises the benefit of all stakeholders. In selecting the preferred option, the following are considered.

- The scale of the project and the possibility of staging
- The option provides the highest NPV
- The extent to which each option performs against each scenario (the highest expected NPV)
- The assessment of other possible intangible benefits (a qualitative account)

2.10 Optimisation

The cost benefit analysis for a proposed network investment is generally carried out during both the annual review and the Area Plan stage. A decision on the project need date (the date the project needs to be completed to address the need for the project) is made at this stage. The sensitivity analysis is also aimed at the identification of the effect of deferral or advancing the baseline need date. Once the suite of projects is developed, the next step is to understand the practicality of delivering the project in time or cash flow lumpiness which may require smoothing out the need dates. Essentially, the project timing may be re-arranged in accordance with other priority requirements. These are:

- Fulfil other obligations such as environmental act requirement, regulatory requirement etc.
- Smoothing out the project delivery plan.
- Dependency on the projects.
- Unexpected change/deterioration of condition of equipment which requires immediate replacement.
- Demand management analysis outcomes.

3 Input Data and Key Assumptions

3.1 Data sources

Data sets used in this analysis are collected from a number of sources within Ausgrid and from other stakeholders. The major data used in this analysis are summarised below.

- Spatial load forecast
- Network electrical connectivity models (PSS/E)
- Condition of network elements (failure rate, repair time, repair cost etc.)
- Load transfer capability between substations
- Switching time
- Safety/environment risk evaluation parameters
- Maintenance costs
- Project cost and cash flow
- Value of Customer Reliability (VCR)

The flow chart below provides a summarised view of the input data, process and outputs that are used in the major projects cost benefit analysis methodology.

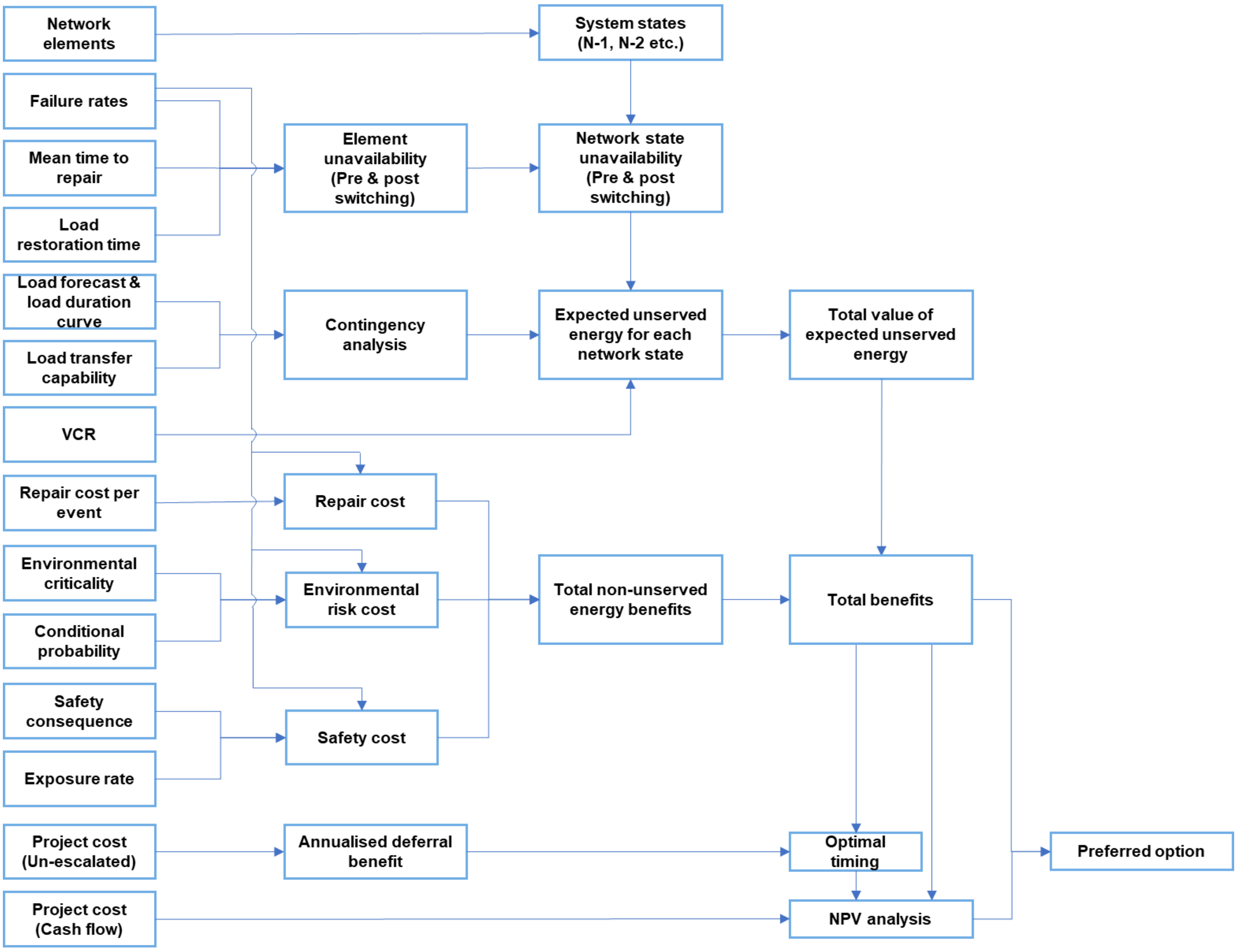

Figure 3-1 Details of input data, process and output of cost benefit analysis

The following sections describe the key input data and the consideration of assumptions used in the analysis.

3.2 Load forecast

Ausgrid develops a spatial peak demand load forecast for the next 20 years based on historical actual loads undertaking necessary adjustments such as weather corrections, rate of growth and foreseeable spot loads. These load forecasts are developed at various confidence interval levels such as POE10, POE50[1] and POE90. Planning studies are generally performed based on the POE50 forecast data and sensitivity studies are performed with other POE and scenario forecasts. The following diagram illustrates a load forecast at three different POE levels for a particular substation. In addition to these forecasts, four scenario forecasts as described in Section 2.8 are developed to perform scenario planning studies.

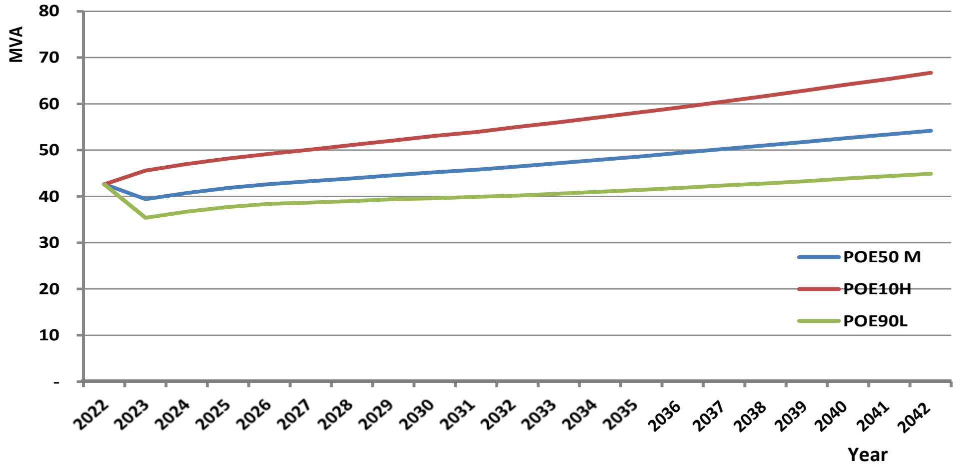

Figure 3-2 Load Forecast

The load forecasts shown above are generally determined for both peak summer and winter loads at a substation. However, it should be noted that, at most times, the substation load is much lower than the peak load. As a result, the load duration curve of a substation is used to estimate unserved energy at various load levels as part of the cost-benefit analysis. This provides an estimation of the unserved energy at various load levels, noting that load curtailment may not be required at lower load levels. The load duration curves are developed using the historical data expressed in per unit values. The diagram below shows a set of typical annual load duration curves which have been developed based on the categorisation of Ausgrid load types.

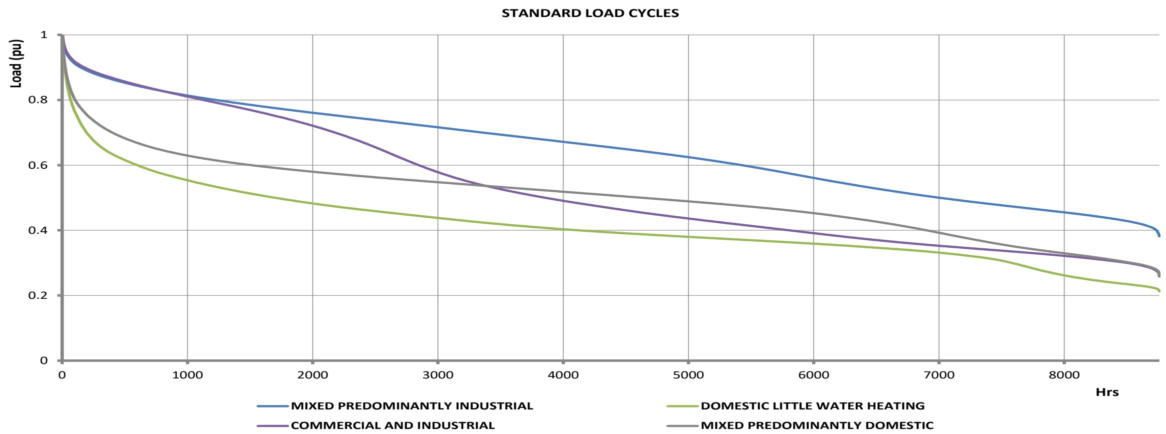

Figure 3-3 Load Duration Curves

[1] Probability of Exceedance 50th Percentile

Where possible, the results of the studies are confirmed by running the models using actual load duration curves extracted from recorded metering data.

Assumptions:

- The maximum load is determined based on summer or winter peak at the zone substation.
- One of the above load duration curves or the load duration curve based on the actual historical data is assigned to a zone substation. Generally, a load cycle has been assigned for each transformer group with the most appropriate one used to represent the zone substation's load profile.
- The per unit load duration curve is assumed identical for future year studies.

3.3 Project costs

Investment cost estimation is a key element of cost benefit analysis. Ausgrid's cost estimation approach is based on unit rates and building block costs of assets. Estimates and unit rates are developed and updated within an established governance process for review and acceptance of these unit rates before use. The project cost estimates also reflect the cash flow over the construction period of the proposed project where it spans multiple years.

3.4 Discount rate

To ascertain the preferred investment option, a two-step process is considered. In the first step, to ascertain the initial timing of the network investment, costs and benefits are compared on an annualised basis, and both are expressed in constant or un-escalated dollars. In the second step, a full economic analysis is carried out to consider that some investments require several years to be completed, and the benefits are only realised over a number of years once the investment is finalised/ commissioned. As a result, investment and benefits cashflows are discounted using a discount rate equivalent to the Weighted Average Cost of Capital (**WACC**), which represents the opportunity cost of Ausgrid's capital.

3.5 Ratings of equipment

The capacity of network elements is based on thermal ratings calculated within Ausgrid's Ratings & Impedance Calculator (RIC). In general, normal and emergency ratings are calculated for each network element in the Ausgrid network.

3.6 Load transfer

3.6.1 Capacity

The load transfer capability at a substation is the amount of load normally supplied from a faulty section of busbar that can transferred to a healthy section of busbar within the same station or to adjacent zone substations via the existing 11kV feeder network. The extent of transfer capacity is dependent upon the availability of network connectivity and the capacity that can be taken from the alternative supply without causing equipment to be overloaded.

3.6.2 Switching time

To evaluate network consequence (unserved energy), it is essential to consider the time taken to do the necessary switching to effect the load transfer.

Figure 3-4 illustrates how the effect of load transfers is modelled taking into account the time taken to do the necessary switching.

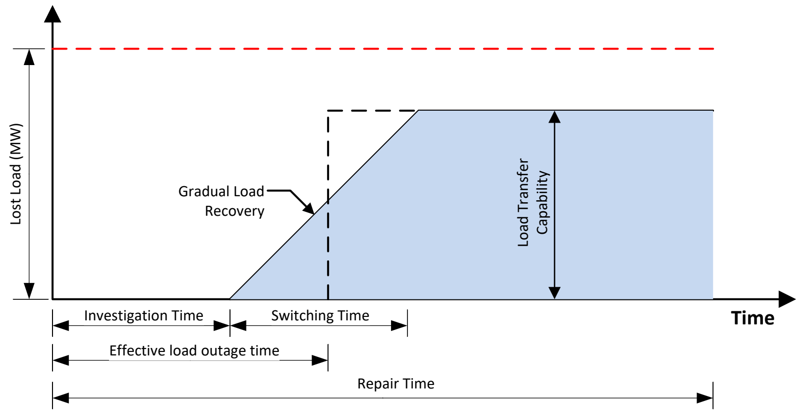

Figure 3-4 Load Transfer (Indicative Switching Time)

Where load transfers are done automatically or can be done by remote switching, it is assumed that the load is transferred immediately.

3.7 Failure statistics

3.7.1 Data sources

Ausgrid has a history of over 100 years, and it represents an amalgamation of many different organisations that have had many different systems to collect information relating to the performance of the equipment. It is anticipated that as the data requirements for probabilistic planning are refined, Ausgrid will update its existing systems to ensure that the appropriate data can be extracted.

The following sections describe the aspects of failure data of the major equipment where this methodology has been applied.

3.7.2 Zone substation 11kV switchgear

The following diagram shows typical 11kV switchgear arrangements found in Ausgrid's network. Normally, the sections of busbar are not operated in parallel. The failure of a bus section would result in the loss of supply to all feeders connected to that bus section. In many zone substations, there are systems to automatically close a bus section breaker if supply is lost to any section of busbar, but this is only useful in the event of a failure of the transformers supplying that busbar and is of no benefit it there is a fault on the busbar itself.

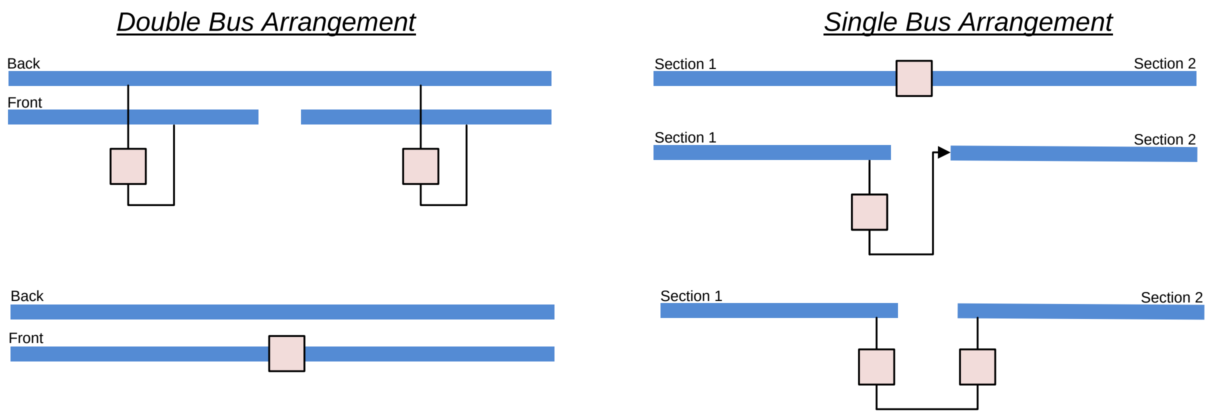

Figure 3-5 11kV Bus Section Arrangements

The condition of 11kV switchgear is determined through periodic testing of both the switchgear and circuit breakers. Consistent with industry practice, the tests performed in Ausgrid are Dielectric Dissipation Factor (DDF), Partial Discharge and Insulation Resistance. Through these tests and historical failure rates, the replacement of these assets is prioritised. The condition information is applied to the generic failure rate parameter β weighted with the specific condition factors and adjusted within a 95% confidence interval on the switchboard panel population distribution. By using historical failure data and the average repair times, the unavailability of 11kV switchgear can be modelled enabling the expected value of unserved energy to then be determined.

3.7.2.1 Failure Parameters of 11kV circuit breakers

There are two types of 11kV circuit breakers in Ausgrid zone substations, namely oil and vacuum. Due to the fire risk associated with oil circuit breakers, the current strategy is to replace these with vacuum circuit breakers. At some of the older substations, vacuum circuit breakers cannot be accommodated in the existing switchgear. In these substations, the oil breakers will be retained until the replacement of the complete switchgear can be justified.

During many years of service, the vacuum breaker technology has proven to be extremely reliable and, unlike the experience with oil circuit breakers, there has not been any incident where a failure of a vacuum circuit breaker has led to a major failure of the associated busbar.

For this reason, the failure of a vacuum circuit breaker will result in a minimal loss of supply and hence the failure of vacuum circuit breakers is not considered in the model. On the other hand, the failure of oil circuit breakers can cause significant damage to the associated busbar, and these probabilities are included in the analysis.

The following input data is used to describe the circuit breakers. Minor failures described in the table below are assumed to be negligible and therefore not included in the model.

Table 3-1: Oil circuit breaker parameters

Description		Category
Circuit Breaker Type		Oil or Vacuum
Condition		Good, Average or Poor
Failure Rate	Minor	Estimated number of failures per year (negligible)
	Major	Estimated number of failures per year that lead to a busbar failure (constant rate)
Mean Time to Repair (MTTR)		Number of hours to repair the bus and put back into service

3.7.2.2 Failure Parameters of 11kV busbars

For the purpose of this analysis, most failures of 11kV bus sections are assumed to be repairable / replaceable, and that the busbar can be put back into service after necessary repair works or replacement of damaged parts are undertaken. Two types of failures, minor and major are considered in the analysis. Minor failures are represented by constant failure rates and are characterised by relatively short duration repair times, whereas the probability major of failures are defined in terms of a Weibull distribution and take a longer time to repair (typically in days or weeks). With this Weibull distribution, the probability of failure varies with time with an increasing probability as the equipment ages.

The following input data is used to describe 11kV busbars.

Table 3-2: Switchboard parameters

Description		Category
Busbar Type		Air or Compound
Condition		Good, Average or Poor
Failure Rate	Minor	Estimated number of failures per year
	Major	Based on Weibull parameters β – Shape factor μ – Scale factor
Mean Time to Repair (MTTR)		Number of hours to repair the bus and put back into service
Age		Based on the commissioned date

The Weibull function is denoted as $f(t)$, where t is expressed in years and the parameters of the function have been derived by analysing the following statistical information.

- The age of Ausgrid's in service 11kV switchboards
- The age of functional failure for Ausgrid's failed switchboards
- The age of retirement for Ausgrid's switchboards that were retired before the point of functional failure

A typical probability distribution function $f(t)$ is shown below in Figure 3-6 (shape = 8, scale = 65).

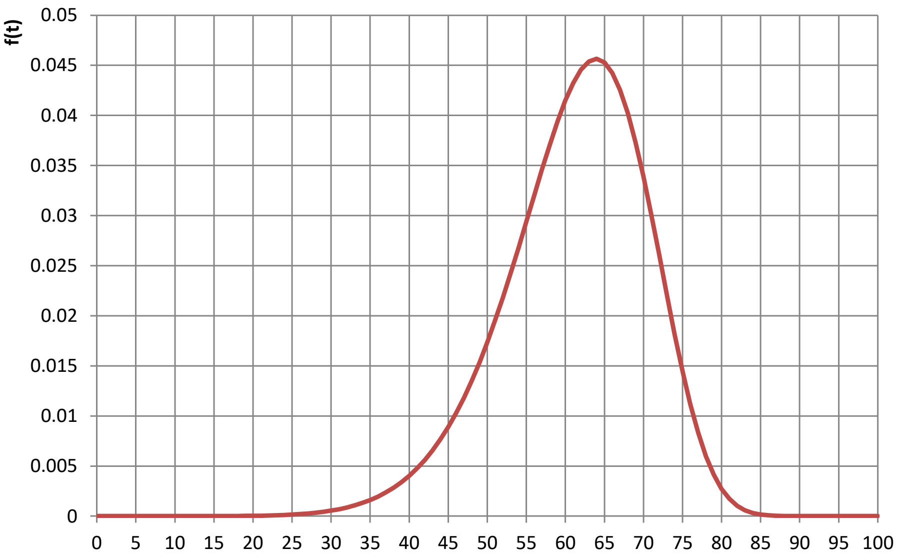

Figure 3-6: 11kV switchboard probability density function

The probability distribution function represents the failure intensity for age t. The concept of conditional probability is applied to evaluate the likelihood of failure. The probability of a failure of an asset occurring within the next year, after having survived for t years, is be calculated by the following equation[2]

[2] ***Wenyuan Li**, Risk Assessment of Power Systems, Wiley and Sons, Vancouver, 2014 (pg 20)*

$$P_f = \frac{\int_t^{t+1} f(t)dt}{\int_t^{\infty} f(t)dt} \qquad (2)$$

Figure 3-7 shows P_f when the above equation is applied to the probability distribution function $f(t)$ shown in Figure 3-6. Year by year P_f is used in the evaluation of risk in the cost benefit analysis.

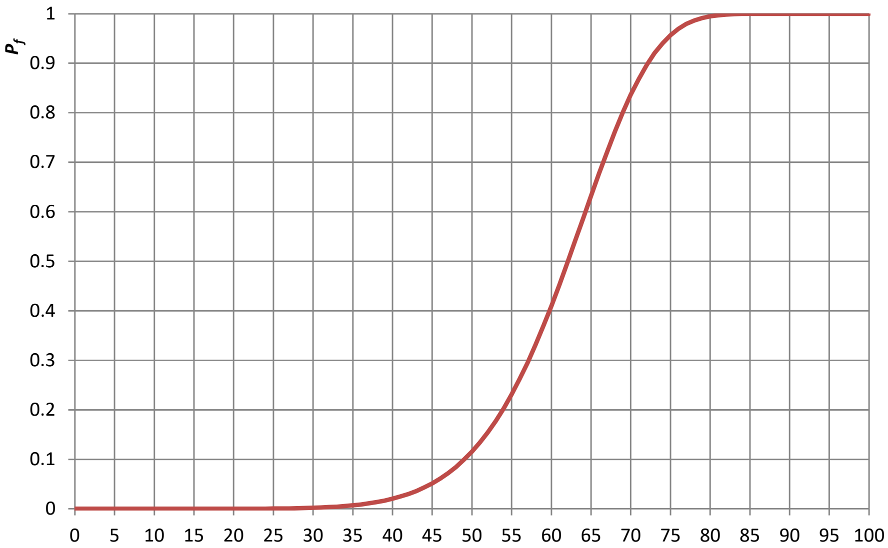

Figure *3-7*: 11kV switchboard cumulative distribution function

The Weibull Parameters are determined based on analysis of the performance of the large population of equipment in the Ausgrid network. To simplify the process of collecting and entering data into the models, separate sets of parameters are determined for whether the equipment was in Good, Fair or Poor condition.

The condition of the equipment in the different stations was ranked according to the maintenance test results. The top 5% of the installations were deemed to be in Good condition and the bottom 5% of the installations were deemed to be in Poor condition. The remaining installations were considered to be in Average condition.

Assumptions:

- All the circuit breaker and switchboard failures are repairable/replaceable as necessary.
- The failure of either front or back bar of double bus arrangement will not be propagated to the other bus which will be in service.
- The failure of vacuum circuit breakers would not cause an outage of corresponding busbar sections.
- The failure of circuit breakers between bus sections would take out both sections which are connected, except in the case of a single bus arrangement when bus sections are connected via two circuit breakers.
- There have been no explosive failures of a vacuum circuit breaker so the safety risk due to vacuum circuit breakers is assumed negligible.
- The condition of similar type of switchboards at a single zone substation is assumed identical.

3.7.3 Sub-transmission cables

There are predominantly four types of cables used in the Ausgrid network which are described in

Table 3-3.

Table 3-3: Ausgrid's cable types

Type	Category
XLPE	Used for all new 33kV, 66kV and 132kV feeders since 1980s
HSL	Installed from 1920s to 1970s (typically in 33kV)
Gas Pressurised	Installed from 1960s to 1980s (typically in 33kV)
Self-Contained Fluid Filled (Oil-Filled)	Installed from 1960s to 1980s (typically in 33kV, 66kV and 132kV)

Ausgrid models cable failures as a non-homogeneous Poisson process where all failures are considered to be repairable. A power law model[3], commonly known as the Crow-AMSAA model, is used to describe this process for a population of cables of a particular type (XLPE, HSL, Gas or Oil-filled). The model assumes a cable segment that has failed can be repaired multiple times over its lifetime. The Crow-AMSAA model has a Weibull intensity function given by:

$$z(T) = \lambda\beta T^{\beta-1} \tag{3}$$

Where:

$z(T)$ is the failure intensity at time T (per km)
T is the cumulative time (i.e. age of the cable at failure, in years)
β is the shape parameter
λ is the scale parameter

The above process is carried out for various failure modes, namely:

- corrective actions;
- breakdowns; and
- third party damage.

Once the Weibull intensity function parameters are known for each cable population and each failure type, the β parameter is weighted by a condition score for each cable based on the historical oil leaks and insulation resistance (**IR**) test results for that cable. The weighting can vary the β parameter within the 95% confidence interval determined for the population parameters. In this way the cable failure model incorporates measures of condition in addition to age which is commonly used as a proxy for condition.

For each cable and failure type, Weibull parameters are determined as shown below.

Table 3-4: Underground cable parameters

Description	Category
Cable Type	XLPE, HSL, Gas or Oil-filled
Failure Mode	Corrective actions, breakdowns and third part damage

[3] See AS IEC 61164-2008 Reliability growth - Statistical test and estimation methods

Failure Rate	Based on Weibull intensity function parameters β – Shape factor λ – Scale factor
Mean Time to Repair (MTTR)	Number of weeks to repair the cable and put back into service (for each cable type and failure mode)
Age	Based on the commissioned date
Length	Length of each cable type in a feeder

Assumptions:

- All cable failures are repairable.
- All cable failures can be categorised as either Corrective Actions, Breakdowns, or Third-Party Damage.
- Failures for equipment that do not have a deteriorating failure model are assumed to be sufficiently rare that they can be ignored. Ausgrid's sub-transmission feeders have a deteriorating failure model.
- When cable failures overload the network, the minimum amount of load is shed to relieve those overloads.
- Conditional feeder ratings are applied, where available, to maximise the capacity of the transmission feeder network. Ausgrid utilises conditional feeder ratings for underground cables where a higher throughput rating can be tolerated during outages of parallel cables.
- The unavailability of associated feeder circuit breakers is not included.

3.7.4 HV switchgear – 33kV to 132kV

The types of switchgear for voltages 33kV to 132kV used in the Ausgrid network which are described in Table 3-5.

Table 3-5: Ausgrid's Switchgear Types for all Sub-transmission Voltages

Type	Category
Outdoor Circuit Breakers (OCB)	Bulk Oil Vacuum GIS Live or Dead Tank (132kV)
Outdoor Isolating and Earthing Switches	Air
Outdoor Busbar	Air
Post Current Transformers	Bulk Oil
Post Voltage Transformers	Bulk Oil
Indoor Switchgear	GIS Air (33kV)

Failures of any of the above switchgear types in Table 3-5 are assumed to be repairable/replaceable, and that the equipment can be put back into service after necessary repair works or replacement of damaged parts are undertaken. Ausgrid models these failures by assuming constant unplanned (forced) failure rates. These Unplanned Failure rates and Mean Time to Repair are available by switchgear category voltage and manufacturer where available. In the case of failure data not being available industry standard failure rates[4] have been used.

3.7.5 Overhead transmission lines

In comparison with sub-transmission cables, the repair time for failures of overhead transmission lines is generally quite short and it would not be possible to justify the replacement or reinforcement of a line purely on the basis of expected unserved energy. Overhead feeders are not assessed in isolation for replacement requirement, however included in the analysis it is part of the underground feeder.

In the very few situations where the failure of an overhead transmission line will have significant impact, Ausgrid has developed contingency plans to minimise the impact of any possible failure.

3.7.6 Power transformers

The failure rate of transformers is expressed in terms of the Weibull distribution with sets of parameters for the different transformer types.

3.8 Other inputs and assumptions

3.8.1 Value of customer reliability (VCR)

The Value of Customer Reliability is a measure of the value that the customer places on the reliability of supply and is measured in dollars per MWh. This figure cannot be directly "measured" but must be estimated based on surveys and discussions with customers.

Ausgrid uses AER published VCR values to estimate the value of the unserved energy, which include annual updates to values using Customer Price Index (CPI). Where this information is not available, VCR values are updated using published CPI values to ensure the real value of the VCR is maintained. Where applicable and practical, the customer specific VCR values are used in the assessment.

3.8.2 Direct cost of equipment failures

For switchboard failures, these costs are estimated based on the following tasks to be undertaken in the event of an outage.

- Access investigation
- Causal analysis
- Engineered solution (T & D)
- Manufacture/repair engineered solution
- Implement engineered solution
- Ancillary works, testing etc.

For cable failures, these costs are estimated based on following tasks to be undertaken in the event of an outage.

- Labour costs
- Material costs

[4] Industry Standard Failure Rates available from the ENA Guide on Reliability Planning (ESAA DOC 006 – 1997 – Guidelines for Reliability Assessment Planning)

- Contracted services
- Jointing works
- Traffic control
- Protection & earthing

4 Evaluation of Benefits

4.1 Evaluation of benefits

The cost benefit analysis used to justify capital expenditure must take into account certain "risks" which can have an influence on planning decisions.

The benefits that are evaluated within the modelling methodology include:

- Reduced Expected Unserved Energy (**EUE**)
- Reduced safety risk
- Reduced maintenance and repair cost
- Reduced environmental risk

The following sections discuss each of above items.

4.2 Reduced expected unserved energy

4.2.1 Failure Rates

Switchboards and transformers:

The following equation is used to calculate the yearly major failure rates based on the Weibull parameters related to the condition of the switchboard.

$$f = \left(\frac{\beta}{\mu}\right) \times \left(\frac{t}{\mu}\right)^{(\beta-1)} \tag{4}$$

Where:

f is the failure rate
β is the shape parameter
μ is the scale parameter
t is the age (years)

Sub-transmission cables:

The frequency of corrective action or failure is determined by applying the equation below to each cable segment.

$$f = L\lambda\left(t_2^{\eta} - t_1^{\eta}\right) \tag{5}$$

Where:

f is the frequency of failures
L is the length of the cable segment (km)
μ is a measure of the failure rate
t_1 is the age of the cable segment at the start of the year (years)
t_2 is the age of the cable segment at the end of the year (years)

Third part damage is an average constant rate determined by the total population of cables.

The EUE is the probability weighted average amount of load that would need to be involuntary curtailed due to system limitations. These limitations arise from the unavailability of network elements and the resulting reduction in network capacity to supply the load.

4.2.2 Unavailability

The element unavailability (hours/year) is calculated by applying equation 6.

$$U = f \times MTTR \tag{6}$$

Where;
f is the average failure frequency of an element (failures/year)
$MTTR$ is the mean time to repair (hours)

As the load transfer via switching is included in the analysis, the unavailability is split into two components, namely pre-switching unavailability and post-switching unavailability. The equations below calculate these unavailability values.

$$U_{pre-switching} = f \times Switching\ time \tag{7}$$

$$U_{post-switching} = f \times (MTTR - Switching\ time) \tag{8}$$

In the case of feeder analysis, a feeder is generally comprised of multiple cable segments. Each cable segment unavailability is calculated taking the union of the corrective actions, breakdowns and third-party damage unavailability values as shown in Equation 8. Then, the feeder unavailability is calculated by taking the union of all the respective segment unavailability values.

$$U_{total,segment} = U_{corrective\ actions} \cup U_{failures} \cup U_{TPD} \tag{9}$$

$$U_{total,feeder} = U_{segment\ 1} \cup U_{segment\ 2} \cup \ldots \tag{10}$$

The probability of outage of an element (unavailability) is the proportion of time that an element is not available to supply the load. This can be calculated for each state (pre-switching and post-switching) as equation 10.

$$P = \frac{U}{8760} \tag{11}$$

Where;
8760 is the number of hours in a 365-day year

The Expected Unserved Energy has been calculated by enumerating all the system states that result in an inability of the network to service the load. This is performed for a discrete set of load levels obtained from the load duration curve for each substation. The probability of residing in each state is calculated from the unavailability of each component. Therefore, the probability of residing in each state is given by equation 12.

$$P(s) = \prod_{i=1}^{N_d} PF_i \prod_{i=1}^{N-N_d} (1 - PF_i) \tag{12}$$

Where:
N is the total number of components

N_d is the number of failed components
PF_i is the unavailability of ith component

4.2.3 Load curtailment & energy at risk

Under a contingency event, the load may need to be curtailed to avoid the other elements of the network being overloaded (system limitations). The operator takes necessary actions to shed partial load until the constrained network element is relieved. In addition, there may be situations where the load will be tripped off automatically due to the nature of the contingency event (switchboard failure). This is related to the availability of network connectivity and design configuration at the substation.

The load duration curve at a substation is used to determine the amount of load curtailment required at certain loading levels. Using a discrete number of load points and the capacity adequacy at the substation, the amount of load curtailment can be determined. As seen in the figure below, at some lower loading levels, load curtailment is not required. These low loading levels may represent off peak times such as night-time and holidays. For a major contingency event, it is assumed that the System Control Room will take necessary actions to switch on and off loads depending on the loading levels. Energy at risk is the area under the curve as shown below.

The following diagram illustrates the load curtailment due to overloads and the treatment of load transfer capability. During an overload condition, initially the necessary amount of load is shed, and then partial load is restored via available load transfer opportunities to surrounding zone substations.

Energy at risk due to overloads of the network is illustrated in the diagram below.

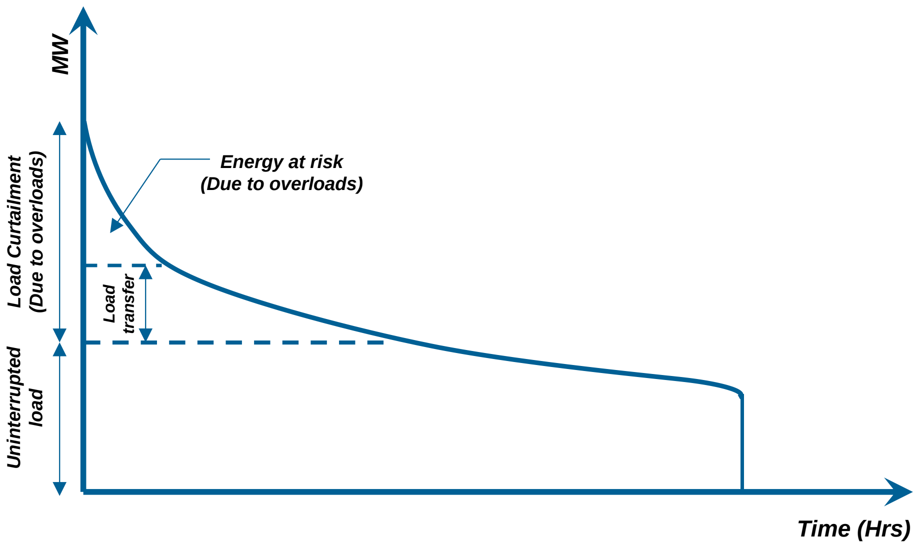

Figure 4-1 Illustration of Load Curtailment

$$Energy\ At\ Risk\ (Overloads) = Area\ of\ the\ curve\ (as\ shown\ above) \tag{13}$$

If the load cannot be supplied due to network connectivity[5], the supply to the load will be lost regardless the size of the load, and hence the entire load duration curve will be used in the estimation.

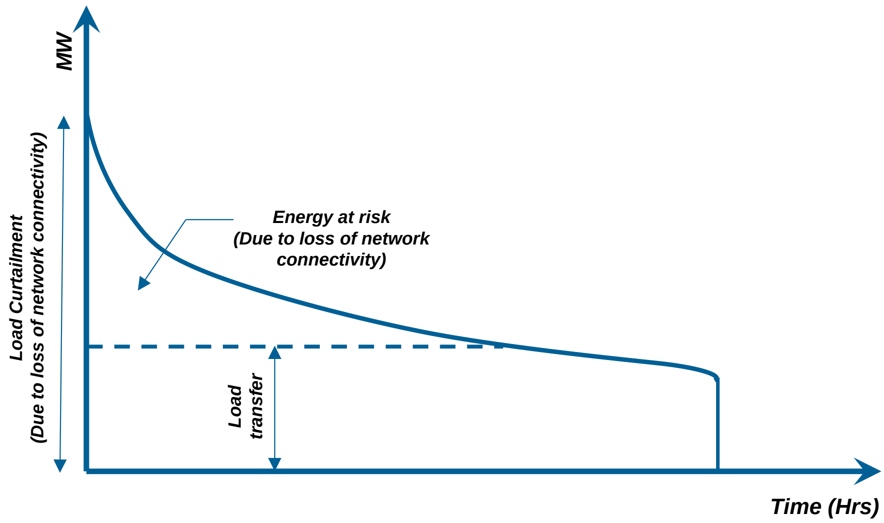

Figure 4-2 Illustration of Load Curtailment/Transfer

$$Energy\ At\ Risk\ (Connectivity) = Area\ of\ the\ curve\ (as\ shown\ above) \tag{14}$$

4.2.4 Expected unserved energy

The Expected Unserved Energy (EUE) is the probability weighted average amount of load that would need to be involuntarily curtailed due to system limitations. These limitations arise from the unavailability of network elements and the resulting reduction in network capacity to supply the load.

The expected unserved energy is the sum of product of energy at risk and probability of each state.

$$EUE = \sum_{n-1}^{n} energy\ at\ risk \times P(s) \tag{15}$$

Where;

n is the number of states

$P(s)$ is the probability of each state

The value of expected unserved energy is the product of expected unserved energy and the value of customer reliability.

This can be represented by equation 16.

$$Value\ of\ Expected\ Unserved\ Energy = (EUE \times VCR)_{pre-switching} + (EUE \times VCR)_{post-switching} \tag{16}$$

[5] The connectivity is defined as the complete loss of supply to a bus section, and no possibility to recover the load apart from 11kV connections to surrounding substations.

4.3 Reduced safety risk

Most busbar faults are cleared successfully in which case there is no risk to personal safety. However, there is a possibility that some busbar failures could be explosive and, under these circumstances it is possible that personnel in the vicinity could be injured or even killed.

The probability of this occurring is extremely low since, for most of the time, the substation is unattended and, even if there were persons at the station at the time of a failure, there is only a remote probability that they would be close enough to the failed switchgear to be affected.

The quantification of safety risk is undertaken as shown below.

$$Safety\ risk\ cost = F \times S \times \alpha \tag{17}$$

Where;

F is the failure rate of the equipment

S is the safety consequence (based on the Value of Loss Load and the Grossly Disproportionate Factor)

α is a factor calculated based on the conditional probability and the exposure rate

The α factor is determined based on an engineering assessment of the probability of a failure of the equipment resulting in a safety incident. This assessment is based on the type of equipment (air insulated equipment without phase segregation pose a greater safety risk), the regularity at which staff visit the site and the proportion of time that such staff would be in close proximity to the equipment.

4.4 Reduced maintenance and repair cost

The replacement of old equipment with new equipment will normally reduce the costs of routine maintenance. Where this difference is significant, it is included in the analysis.

In the event of a serious failure of an 11kV busbar which would require the equipment to be replaced, temporary repairs would need to be done to maintain supply until the replacement busbar is commissioned. As this cost is avoided if the busbar is replaced before any failure takes place, this repair cost represents a saving and is factored into the cost benefit analysis.

The following equation is used to calculate the impact of repair cost.

$$Repair\ cost = F \times D \tag{18}$$

Where;

F is the failure rate

D is the repair cost per event

4.5 Reduced environmental risk

Ausgrid has experienced major leaks from oil filled cables and some Ausgrid cables leak smaller amounts of oil into the environment that are difficult to locate and repair. Ausgrid policy is to minimise environmental impact to the extent it is practical. Regardless, oil leaks expose Ausgrid to a risk of liability under the Protection of the Environment Operations Act 1997 (NSW), particularly in relation to pollution of water and pollution of land.

It is necessary to include the environmental risk in the cost benefit analysis as the continued service of oil-filled cables will result in further deterioration in condition and an increasing number of failures that are random in nature. These failures have the potential to cause damage to the environment.

The quantification of environmental risk is carried out using the method shown below.

$$Environmental\ risk\ cost = F \times EC \times \beta \tag{19}$$

Where;

F is the failure rate of the equipment

EC is the environmental criticality

β is a factor calculated based on the conditional probability of ground water impacts from an oil leak of the feeder

The Environmental Criticality (EC) is calculated for the three feeder failure types described in Section 3.7.3 namely:

- corrective actions;
- breakdowns; and
- third party damage.

Each failure type is made up by a group of possible failure modes. For each failure type, the Mean Time To Repair (MTTR) is determined by taking the average of the repair times for each failure mode assuming equal likelihood for each failure mode within that failure type. The proportion of the year that would be impacted by a single equivalent failure is then used to weight the monetised consequence of a significant oil leak to produce the Environmental Criticality for each failure type.

$$Environmental\ Criticality = \frac{MTTR}{52} \times Sig.oil\ leak\ cost \tag{20}$$

Where;

$MTTR$ is the Mean Time To Repair in weeks

$Sig.oil\ leak\ cost$ is the annual monetised worth of a detectable oil leak of 5L per day for one year multiplied by $3,000/L[6] (5L x 365 days x $3,000 = $5.475 million) plus an amount of $10,446 being a weighted tier two and/or three fine under the POEO Act.

Table 4-1: Environmental Criticality for each failure type

Environmental Criticality		
Corrective Action	**Breakdown**	**Third Party Damage**
$111,883	$632,936	$580,191

[6] (D16/1028628) NSW EPA's Regulatory Impact Statement – Proposed Protection of the Environment Operations (Underground Petroleum Storage Systems) Regulation 2014 – states "*Petroleum can contaminate large volumes of groundwater. For example, according to Environment Canada, one litre of gasoline can contaminate 1,000,000 litres of groundwater.. If water used for domestic purposes is priced at about $3,000/ML (Deloitte Access Economics 2013)…*"

5 Planning Models

5.1 Introduction

Four computer-based models are used to assist in the calculation of the expected value of unserved energy and to perform the cost benefit analysis. They are:

11kV Switchgear - to determine the optimal replacement date for 11kV busbars and associated switchgear in Zone Substations

33kV-132kV Switchgear - to determine the optimal replacement date for 33kV-132kV busbars and associated switchgear

Zone Capacity - to determine the optimal date to replace or augment Zone Substation transformer capacity

Sub-transmission Feeder - a more general model to determine the amount of unserved energy based on probable outages of various critical network elements.

5.2 11kV switchgear model

The 11kV Switchgear model has been designed to determine the optimal replacement date of 11kV switchgear in Zone Substations.

The 11kV network is typically a radial network and any failure of an 11kV busbar will result in a loss of load until the network is switched to supply all or part of the load from another source. In these circumstances, it is not necessarily required to undertake load flow calculations to determine the value of lost load.

The model has been developed in the form of a single Excel Spreadsheet which contains all the information relating to all the Zone Substations in the Ausgrid network.

The busbar arrangement for each of the substations has been entered into the Spreadsheet and facilities are provided to load the following information relating to each substation which has to be sourced from various Ausgrid corporate systems.

Table 5-1: Input data for 11kV Switchgear Model

Data Type	Description
Load forecasts	MW and MVAr for 20-year planning horizon
Transfer Capacity (MVA)	Transfer capacity and Switching Steps
Project Cost ($)	Solution cost

The model determines the optimal switchgear replacement date by determining the first year when the total costs of expected unserved energy, maintenance and safety risk exceeds the value of a one-year deferral of the project.

Note that this model does not make provision for environmental risks as such risks are inconsequential in the analysis.

5.3 33kV to 132kV switchgear model

The Switchgear model for all voltages 33kV to 132kV has been designed to determine the optimal replacement date of switchgear of these voltages in Zone and Sub-transmission Substations.

The sub-transmission network has been designed to N-1 network security. An initial screening test to determine the value of lost load involves undertaking load flow calculations to determine loading at worst case N-1 contingencies. If 100% utilisation is not exceeded under these conditions, then it is very unlikely that any significant unserved energy will be calculated. Thus, the model is not tested under these conditions.

For situations where it is found that 100% peak load exists, then the Switchgear model is tested to determine the value of lost load.

For condition-based asset drivers, the model is tested to determine unserved energy at locations where condition-based asset drivers have been identified by the Asset Risk & Performance section.

The model is programmatically implemented in Matlab. The table below shows all the required input data.

Table 5-2: Input data for 33 to 132kV Switchgear Model

Data Type	Description
Load forecasts	MW and MVAr for 20-year planning horizon
Transfer Capacity (MVA)	Transfer capacity and Switching Steps
Equipment Failure Rates	All constant failure rates for the study required
Equipment MTTR	All equipment Mean Time to Repair figures required
Substation Outage Type	All substation outage types considered are to be input in this model
Project Cost ($)	Solution cost

The model determines the optimal switchgear replacement date by determining the first year when the differential between the base case and solution exceeds the value of a one-year deferral of the project.

Note that this model does not make provision for environmental risks as such risks are inconsequential in the analysis.

5.4 Zone capacity model

Based on deterministic planning, zone substations were planned to have an (n-1) level of redundancy where there would be no interruption to supply following the failure of a single transformer. The “firm” capacity of the station was defined as the load the station could supply with one transformer out of service.

If the load was forecast to increase beyond the firm capacity of the station, the planner would investigate a range of options to address the situation – including the transfer of load to other stations – but, if the load continued to grow, then a project to add a new transformer or replace the existing transformers with higher rated units would ultimately be required to achieve the required level of reliability.

To apply probabilistic planning, it is necessary to calculate the probable value of unserved energy that would occur if the load was in excess of the firm capacity of the station should a transformer failure occur and a project to augment the capacity of the station would only be initiated when the annualised benefit exceeds the benefit of deferring the project by one year. The Zone Capacity Model calculates the value of unserved energy based on the forecast loads and the failure statistics for the transformers and compares this with the project cost - being the cost of the works identified as the least cost option to address the need.

5.5 Sub-transmission feeder model

5.5.1 Structure

The Feeder Model has been developed in two components. The first component is designed to calculate the amount of expected unserved energy resulting from the failure of an element in a meshed network. In these cases, it is necessary to undertake a load flow analysis for each case to determine the amount of load lost in the event of the failure of specific elements. The load could be lost due to islanding of the network or the need to shed load to avoid overloading in-service elements.

5.5.2 Component 1 – PSSE model

The model is based on PSSE software (the system Ausgrid uses for network studies) and with a specially designed “front end” to facilitate data entry. This front end has been programmed in Python.

The main input to the models is a set of PSSE “.sav” files which accurately define the network being considered. There are two files for each of the study years – one containing forecast summer loadings and the other containing forecast winter loadings. These files are used in the normal planning process and are known to produce accurate results.

The planner then prepares a number of files to define the contingencies he/she wishes to study.

These files are:

Table 5-3: Input files for Feeder Model

Files	Description
Unavailability	Elements which are to be ‘failed’ in the study, and the estimated unavailability of each element
LDC	Load Duration Curves for each of loads
Auto Closing	Switching operations
Load Transfer	Load transfer capability between substations

When the model is “run”, the load flow is “solved” for each combination of possible outages for each year. Where the model indicates that load is lost – either to avoid overloading and in-service elements or as the result of “islanding” a part of the network – the model calculates the estimated amount of unserved energy based on the unavailability of the relevant elements and the load duration curve of the affected loads.

A summary spreadsheet is generated which gives the total estimated amount of unserved for the study period measured in MWh.

5.5.3 Component 2 – spreadsheet model

The details of the amounts of unserved energy are transferred into a spreadsheet model which is designed to:

Compare alternative options for addressing the need

Determining the optimum date for implementing each of the options

Apart from the values of unserved energy derived from the PSSE model, the following additional data is entered into the model

VCR

Project Costs

Failure rates

Taking into account the

Value of unserved energy

Changes in maintenance costs

Changes in the environmental risk

Cost of implementing each of the augmentation options

The model calculates the optimal date for implementing each option based on the first year when the total costs of doing nothing exceed the value of deferring the implementation of the option for one year.