Transformer risk monetisation and investment evaluation methodology

PAL BUS 4.03

Regulatory proposal 2021–2026

Powercor

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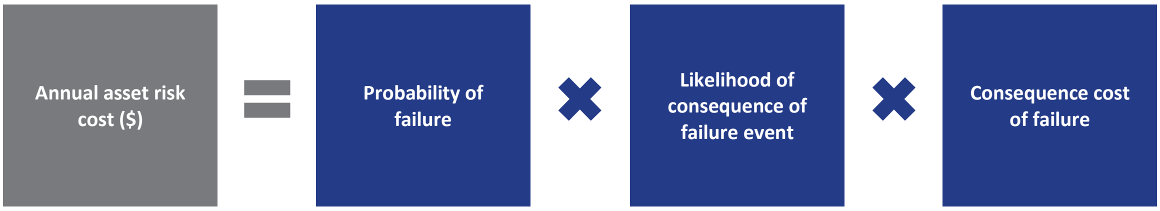
Contents

1 Overview

This document explains our risk monetisation process and how it has been used to determine our zone substation transformer replacement program.

We monetise risk when assessing investment decisions by determining the annual asset risk cost (as shown in figure 1.1). This approach is applied to all identified failure modes for an asset, and the sum of the annual asset risk cost for all of failure modes is compared to the annualised cost of the preferred option to determine the economic timing for any intervention. This approach is consistent with the AER's recent asset replacement guidance practice note.[1]

Figure 1.1 Calculation of annual asset-risk cost



Source: Powercor

Our approach to risk monetisation employs Condition Based Risk Management (**CBRM**) to provide a robust methodology for the preparation and application of the required input information (i.e. the probability of failure, and the likelihood and consequence cost of failure).[2] CBRM enables us to use current asset information, engineering knowledge and practical experience to predict future asset condition, performance and risk for our assets. It is a comprehensive management methodology, which is aligned with the AER's risk monetisation process.

We first implemented the CBRM methodology in 2008, and have continued to develop the models in line with best practice. In 2019, we updated the risk monetisation process for transformer replacements to align with EA Technology's Asset Investment Management software and the Common Network Asset Indices Methodology (**CNAIM**) adopted by the Office of Gas and Electricity Markets (**Ofgem**).[3]

As set out in our regulatory proposal, we propose the following transformer replacements in the 2021–2026 regulatory period:

- Robinvale zone substation: transformer number one
- Robinvale zone substation: transformer number two
- Warrnambool zone substation: transformer number three
- Inglewood 66kV regulator.

The specific inputs for each individual transformer replacement are discussed in appendices within this document, and are supported by the attached risk monetisation models.[4]

1 PAL ATT099 - AER, *Industry practice application note: asset replacement planning*, January 2019..

2 The CBRM is a proprietary model developed by EA Technologies. The model is an ageing algorithm that takes into account a range of inputs to produce a health index for each asset in a range from zero to 10 (where zero is a new asset and 10 represents end of life). The health index provides a means of comparing similar assets in terms of their calculated probability of failure.

3 PAL ATT100 - Ofgem, *DNO Common Network Asset Indices Methodology*, version 1.1, 30 January 2017.

4 PAL MOD 4.12 - IWD regulator - Jan2020 - Public; Powercor, PAL MOD 4.13 - RVL transformer no.1 - Jan2020 - Public; Powercor, PAL MOD 4.14 - RVL transformer no.2 - Jan2020 - Public; Powercor, PAL MOD 4.05 - WBL transformer no.3 - Jan2020 - Public

2 Probability of failure

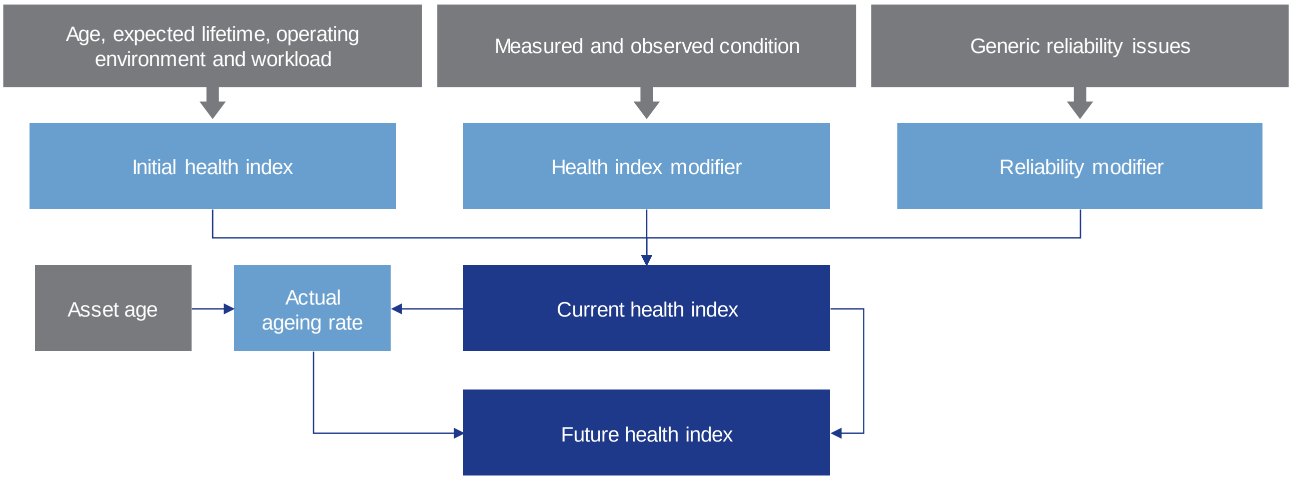
Asset performance is measured in terms of probability of failure and, for each asset category, is determined by matching the 'health index' profile with recent data on failure rates.

Health indices are derived for individual assets by combining information on age, environment, duty and specific condition information. These indices are then projected forward to reflect the asset's ageing rate, which is dependent on its condition and operating environment.

2.1 Determination of health index

The detail of the health index formulation is different for each asset class, reflecting the asset-specific information and degradation processes. There is, however, a consistent approach to determining the health index for all asset classes as shown in figure 2.1.

Figure 2.1 Overview of health index determination



Source: EA Technology

An initial health index for our transformers is calculated using knowledge and experience of the asset's performance and expected lifetime, taking account of factors such as original specification, manufacturer, operational experience and operating conditions (e.g. duty and location). The initial health index is intended to reflect the expected life of the asset. It is capped at 5.5, which means that a transformer will not be considered to be at end of life unless there is specific information that indicates that its condition is deteriorating.

The initial health index is then adjusted by the health index modifier, which is based on the known condition of the asset. It includes information on condition that is gathered by inspecting the asset, together with information relating to asset defects and failures, and condition information obtained through diagnostic tests and oil testing.

A reliability modifier can also be applied to modify the current health index to reflect generic issues affecting asset health and/or reliability associated with a manufacturer or model type, or a specific asset performance issue. It can also be used where a specific material or treatment has been applied to the asset. The reliability modifier should be used where there is evidence to show that a sub-group of assets has a materially different probability of failure compared to other assets with the same health index in that asset category.

In summary, as shown in figure 2.1, the current health index is derived by modifying the initial health index by the health index modifier and the reliability modifier, subject to upper and lower thresholds derived from the condition and reliability data. Information on the degradation of each asset is then used to 'age' the current health index and thus derive the future health index of each asset.

2.2 Determination of probability of failure

The CBRM methodology considers condition-related failures in deriving the probability of failure. These types of failures relate to the inability of an asset to adequately perform its intended function and, hence, are not solely limited to failures that result in an interruption to supply. The failure modes considered in CBRM consider actual historical failure data and experience. The impact of minor failures are not included in the risk monetisation process.

For transformers, the condition related failure modes are listed in table 2.1.

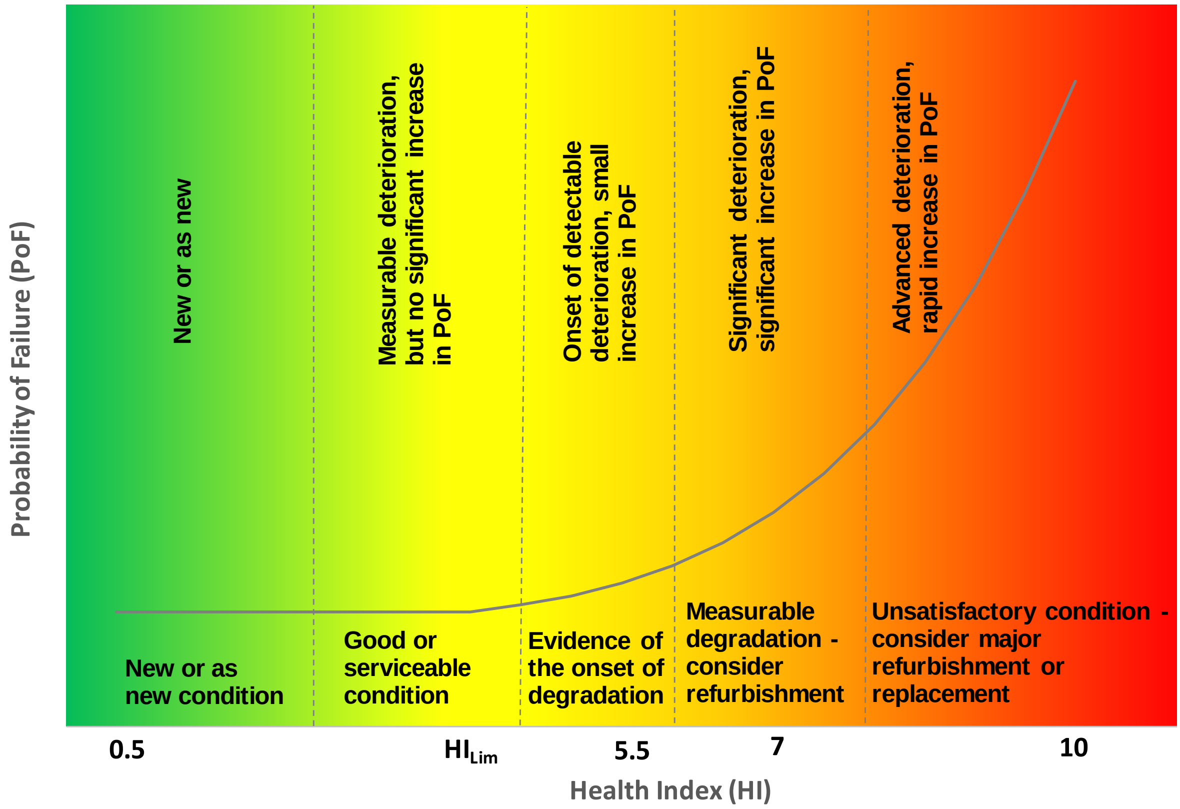
Table 2.1 Failure mode definitions for transformers

Failure mode	Description
Minor	A minor failure which will not cause an unplanned outage.
Significant	A significant failure which will cause an unplanned outage and will require reactive maintenance and network switching to restore supply.
Major	A major failure will cause an unplanned outage and require a replacement unit(s) to be installed to restore supply and/or network security. It may or may not cause damage to adjacent asset(s) due to fire or explosion.
Catastrophic	Catastrophic failure arises if all the transformers at the zone substation fail.

Source: Powercor

The relationship between health index and probability of failure is not linear. An asset can accommodate significant degradation with very little effect on the probability of failure. Conversely, once the degradation becomes significant or widespread, the risk of failure rapidly increases. The probability of failure of an asset is a function of its health index, as shown in figure 2.2.

Figure 2.2 Relationship between health index and probability of failure



Source: EA Technology

Mathematical modelling techniques carried out by EA Technology suggest that a cubic relationship (3rd order polynomial) is appropriate to define the health index and probability of failure relationship as follows:

$$PoF = k \cdot \left(1 + (HI \cdot c) + \frac{(HI \cdot c)^2}{2!} + \frac{(HI \cdot c)^3}{3!}\right)$$

Equation 1

where:

PoF = probability of failure per annum

HI = health index

k & c = constants

The value of c fixes the relative values of the probability of failure for different health indices (i.e. the slope of the curve) and k determines the absolute value; both constants are calibration values.

Practical experience has indicated that this cubic relationship is appropriate for assets with higher health indices. However, at low values it has been found that even modest increases in probability of failure defined by the cubic relationship do not fit with actual experience. Therefore, it has become standard practice to adopt a hybrid relationship. Up to a limit value (HI_{Lim}), the probability of failure is set at a constant value; above HI_{Lim} the cubic relationship applies. Experience suggests that HI_{Lim} be set at 4; this is the value that has been used in our evaluation of the transformer replacement program.

2.2.1 Determination of c

The value of c in equation 1 can be determined by assigning the relative probability of failure values for two health index values (generally HI = 10 and HI = HI_{Lim}). Where reasonably complete information is available that directly relates to the critical degradation processes, there is a fairly high level of confidence in the health indices and, consequently, the relative PoF between the two assets is expected to be high. However, where health indices are predominantly derived from indirect condition related information, leading to a lower level of confidence in the health index, the relative PoF between the two assets is expected to be lower.

In practice, with the use of the hybrid HI / PoF relationship, the value of c is typically set to 1.086, which corresponds to a PoF for an asset with a health index of 10 that is ten times higher than the PoF of a new asset.

2.2.2 Determination of k

The value of k in equation 1 is determined on the basis of:

- the total observed number of functional failures per annum;
- the health index distribution for the asset category; and
- the volume of assets in the asset category.

The asset group can have a different curve shape and height for each failure mode if it is considered appropriate.

For each asset category, k is calculated as follows:

$$k \cdot \sum_{i=1}^{n} \left(1 + HI_i \cdot c + \frac{(HI_i \cdot c)^2}{2!} + \frac{(HI_i \cdot c)^3}{3!} \right) = (\text{Average no. of failures per annum})_I$$ Equation 2

where:

n	=	the number of assets in asset category I
HI_i	=	Health index of asset i

The total experienced failure rate for each failure type is allocated across the asset population based on each asset's health index. Each asset will have a calculated probability for minor, significant and major failures.

Having calculated the health index for each asset, the projected ageing curve can be determined. This projected ageing rate is used to determine the future health index in each year and the resulting probability of failure value for each year.

3 Consequences of failure

Consistent with the CBRM, our risk monetisation approach identifies four consequence categories, which capture the potential impact of asset failure on electricity customers. Table 3.1 shows these risk categories and the associated consequences, each of which can be quantified in dollar terms.

Table 3.1 Consequence categories and consequences of failure

Consequence category	Consequences of failure
Network performance	• Unserved energy • Coincident outages
Safety	• Minor injuries • Serious injuries • Fatality
Financial	• Repair and replacement costs (operating and capital expenditure) • Generation support • Fire brigade attendance
Environmental	• Volume of oil released • Volume of SF6 released to atmosphere • Fire starts • Volume of waste produced • Level of disturbance

Source: Powercor

The calculation of consequence of failure in CBRM uses the same failure modes as the probability of failure. For each of these consequence categories, the actual consequences of failure are considered and used to produce a reference cost of failure, which represents the 'typical' impact of a failure based on historical data.

Each of the four consequence categories is discussed in further detail below.

3.1 Network performance consequences

The network performance consequences of failure consider the relevant zone substation's energy at risk of not being supplied, and the impact of coincident outages.

3.1.1 Unserved energy

The expected average unserved energy costs are based on the energy at risk, the time at risk, and the value of customer reliability (**VCR**) per megawatt hour. The time at risk is based upon the time taken to install generators to restore supply. A weighted average of the 50^{th} and 10^{th} percentile expected unserved energy estimates is calculated by applying weightings of 70% and 30% (respectively).

The unserved energy is initially that which cannot be transferred to alternate supplies following the significant or major failure. This reduces once the generators start to come on line taking account of the number of generators which may be brought on line each day until sufficient generation support has been installed to meet the demand unserved following the initial incident.

3.1.2 Coincident outages

Network performance consequences may include the costs of unserved energy associated with coincident outages (e.g. where a failure coincides with another major or significant failure, a planned outage, or maintenance of assets at that substation). For a catastrophic failure, the impact of the failure of all transformers at the zone substation is captured as 'unserved energy' rather than through the coincident outage calculation.

3.1.3 Likelihood of network performance consequence

The likelihood of consequence is generally set to 100% on the basis that when a particular failure type occurs it is known to have a particular consequence. For example, as the definition of a significant or a major failure is a failure that results in an outage, and the consequences are determined using actual values of load and capacity, then the likelihood of the consequence occurring must be set to 100%. By definition, these failure modes could not occur without causing loss of the asset and some consequences must occur if there is a significant asset failure.

A significant asset failure has been defined as having a single outcome (damage is contained to the failed asset) whereas, for a major failure, there are two possible outcomes:

- the asset failure may result in damage to the adjacent assets, or
- the damage may be contained to the failed asset.

Significant failure

For a significant failure, the impact of failure is the loss of the asset for the time it takes for the repair to be carried out and the asset returned to service. For transformers, the average repair time has been defined from experience and consideration of the CNAIM values, to be 200 hours or 1.19 weeks. The impact of the loss of the transformer will depend on the substation maximum demand, the N-1 cyclic rating and the load transfer capacity. If the substation demand can be met by the remaining transformers at the site and/or load transfer, then there is no network performance risk associated with the failure. However, if the demand cannot be met in this way then there will be some loss of supply.

An additional consideration is the probability of a coincident outage. Although in most cases the failure of a single asset will not lead to an outage, if an asset failure coincided with another major or significant failure, a planned outage, or maintenance of assets at that substation, then the failure would lead to an outage. A small probability of this is also considered.

For major failures, the possibility of a coincident outage is only included for those failures that are contained to the failed asset.

Major failures

A major failure has two possible outcomes: either the transformer failure will result in damage to the transformer, or the failed transformer and adjacent transformers. The replacement time has been set to 6 weeks for a single transformer and 12 weeks for multiple transformers. This is an estimate of the time to procure or borrow and install the transformer. The lead time to purchase a transformer of this type will be considerably longer, so this assumes that a transformer can be obtained or moved to restore the network. The likelihood of damage to the adjacent transformer(s) depends on the layout of the substation and the positioning of the transformers and whether blast walls are present. This outcome will result in the loss of all substation capacity until the asset or assets can be replaced.

In cases where the damage is assumed to be restricted to the failed transformer, a low percentage of these failures may be accompanied by a coincident outage on the network, which would result in an increased consequence. This probability is considered reasonable, given the assets will be of a similar age and condition and may have experienced increased loading or mechanical shock as a result of the initial failure. The same approach is also applied a significant failure, although the outage time is considerably less.

Catastrophic failures

The likelihood of catastrophic failures is determined on a case-by-case basis at each zone substation. For zone substations with only one asset at risk, the likelihood of catastrophic failure is set to zero as the risk of asset failure has already been captured in the other failure modes.

3.2 Safety consequences

The safety consequences of failure represent the quantification of the societal value of preventing an accident, serious injury or fatality. The safety consequence for each failure is derived from the reference safety cost of failure used in the CBRM, modified by the probability of a safety consequence occurring.

The safety consequences are estimated with reference to minor, serious and fatal injuries by applying a dollar value that reflects the seriousness of the incident. A 'disproportion factor' is also applied, which recognises that serious and fatal injuries should be avoided even if the costs of doing so outweighs the actuarial value of the loss incurred.

The safety consequence represents the risk that the asset presents to the workforce and public by its characteristics and particular situation. The safety consequence incorporates a measure of the likelihood that someone would be in the vicinity of the asset at the time of failure. The assessment of the safety consequence recognises that in many cases staff would be present for routine activities or in response to alarms from monitoring or protection equipment (e.g. partial discharge events or Buchholz relay operation) prior to the asset failure.

3.2.1 Likelihood of safety consequences

The value of the safety consequence of asset failure takes into account the likelihood that a failure of each type would result in injury or death. As the likelihood of the consequence is included in defining the value of consequence, the likelihood of consequence value is set at 100% (otherwise the likelihood of consequence would be double-counted in calculating the expected safety risk).

3.3 Financial consequences

The financial consequence of failure of an asset is the cost of repair or replacement to return the network to its pre-fault state, and the cost of temporary generation support.

3.3.1 Replacement costs

The replacement costs of a transformer are based on recent, observed replacement works on our network. The replacement cost for an asset under failure conditions is assumed within the model to be the same as the planned asset replacement unit cost.

3.3.2 Repair costs

The model also provides for repair costs where the replacement of a transformer is not considered necessary. The repair costs are most likely to arise for a significant failure modes, rather than major or catastrophic.

3.3.3 Generation costs

The operating costs for generation to supply load when failed assets are replaced or repaired is also considered in the financial consequences.

Generation costs are based on the load at risk and take account of the time to install and remove generators and step-up transformers, the fuel used whilst supplying the load that is not able to be supported within the network, and the costs to supervise and maintain the generators during the period they are deployed.

The costs associated with the generation are shown in table 3.2.

Table 3.2 Unit costs associated with generation ($, 2019)

Generation	Costs
Generator hire per week	7,000
Fuel cost $ per litre including delivery	1.50
Fitter cost (blended 24hr rate) $ per hr	150
Traffic management and security per site	10,000
Transformer hire per week	7,000
Earthing and bunding per site	2,000
Temporary fencing per site per week	3,000
Miscellaneous material per site	2,000
Install and remove step down transformers per site	2,500
Council permits per site	4,000
Crane hire to install / remove generators per site	2,500
Cable hire per site	3,000

Source: Powercor

3.3.4 Likelihood of financial consequences

A major failure will always require asset replacement. The major failure outcomes are split between the likelihood that a single transformer will require replacement (80%) and that multiple transformers will require replacement (20%).

A significant failure will always require a repair and will have a 100% likelihood of consequence.

3.4 Environmental consequences

The environmental consequences of failure represent the quantification of the potential environmental impacts of failure for each specified failure mode. For each asset, its environmental consequence is derived from the reference environmental cost of failure used in the CBRM, modified by an asset-specific environmental consequence modifier.

For transformers, the unit costs of oil, SF6, fire, disturbance and waste are calibration values (defined by asset category), which have been set with reference to environmental regulations, where applicable. The environmental impacts of an average failure (e.g. volume of oil lost) have been set with reference to recent incidents and the actual environmental impacts resulting from failures.

The environmental consequence considers whether individual assets contain oil or SF6, either as an interruption medium or insulation medium, and the size of the asset, insofar as the size has a direct and material influence on the scale of the environmental consequences.

3.4.1 Likelihood of environmental consequences

The environmental consequences of failure are based on the defined environmental impact of the failure mode in, for example terms of volume of oil lost.

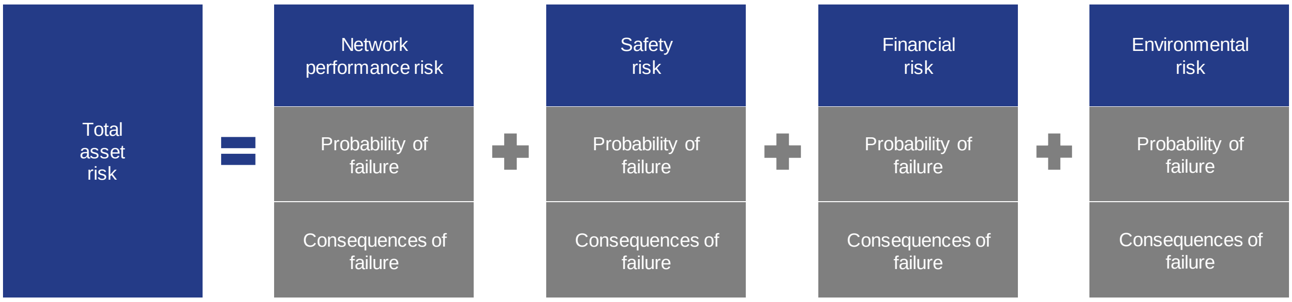
For a major failure the outcomes are split between the environmental impact arising from damage to a single transformer (80%) and the environmental impact caused by damage to multiple assets (20%). A significant failure has a single outcome and will have a 100% likelihood of consequence.

3.5 Total risk quantification

The asset risk in dollar terms is determined by multiplying the probability of an event occurring, and the cost of the resulting consequences if the event occurs (i.e. overall consequence cost multiplied by the likelihood of consequence).

The calculation of asset risk uses the outputs from the probability of failure and consequence of failure for each failure mode to calculate risk in each consequence category. Total asset risk is depicted in figure 3.1.

Figure 3.1 Overview of risk calculation structure



Source: Powercor

The future asset risk in dollar terms is calculated using the forecast probability of failure values that reflect the projected health index values. Consequence values are considered to remain constant, with the network performance consequence based on the maximum projected substation demand in the relevant year.

4 Investment evaluation methodology

The methodology described in the preceding section allows the asset probability of failure and consequence of failure values in the current and future years to be determined and used to project the asset risk over the regulatory period and beyond.

The benefit of a transformer replacement is the reduction in the asset risk, expressed in present value terms. It is noted that there is a very small residual risk associated with new plant, however that risk is not significant and therefore, it can be excluded from the analysis. On this basis, the benefit of transformer replacement is the avoided risk cost of the existing transformer.

4.1 Determining the annualised cost of asset replacement

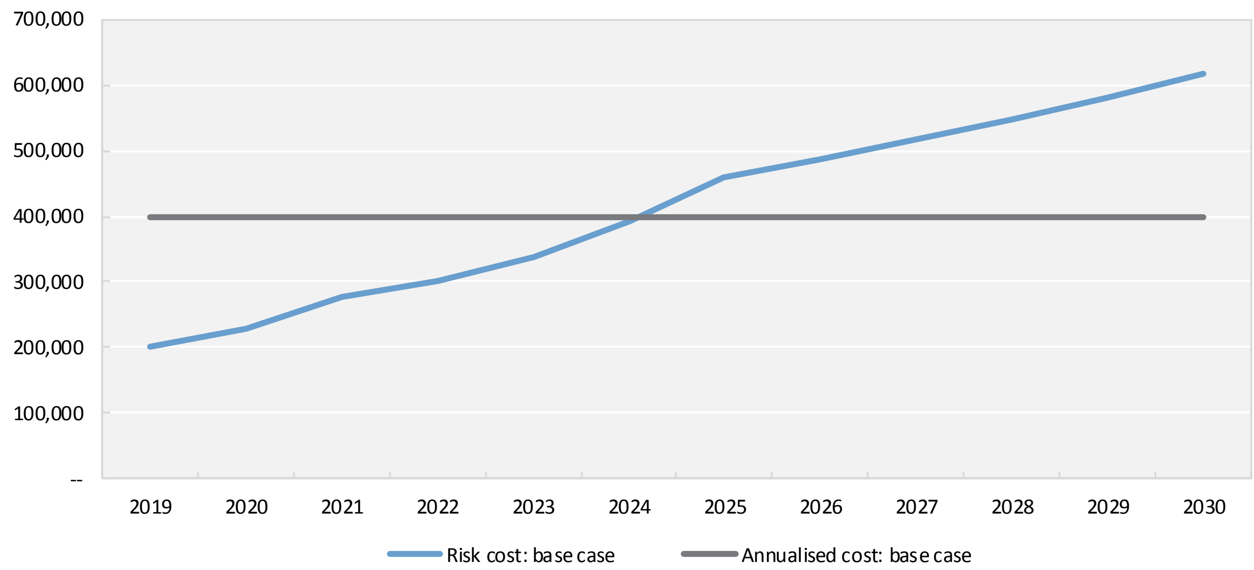
The annualised investment (i.e. asset replacement) cost is calculated based on the investment cost to complete the replacement project and the ongoing operational costs for the asset. The replacement cost used in the calculation is the asset unit cost, and ongoing operating costs are based on the historical average costs associated with routine maintenance and inspection activities.

The total cost is then evaluated using the (real) regulated rate of return, and the resulting total cost is annualised over the 50-year service life of the asset.

4.2 Identifying the optimal timing of replacement

The optimal asset replacement investment timing is identified by comparing the annual monetised risk value of the existing asset and the annualised investment cost. The asset replacement is economic in the year in which the annual monetised risk value is higher than the annualised investment cost, as illustrated in figure 4.1.

Figure 4.1 Comparison of asset risk and annualised cost for base case (for illustrative example only)



Source: Powercor

In the above example, the optimal time to replace would be 2024, as this is the year in which the annual monetised risk cost of the existing asset exceeds the annualised investment cost.

4.3 Modelling different scenarios

Four scenarios are considered to test the sensitivity of the results of the economic assessment to plausible variations in the input values, relative to a 'base case'. Table 4.1 shows the scenarios that are considered.

Table 4.1 Definition of scenarios

Scenario	Description
Base case	Adopts the central estimate for each variable in the economic assessment. It represents the most likely outcome
A	Represents a combination of variables that minimises the net market benefits compared to the risk cost of assets
B	Defines a generic lower bound for the present value costs and the risk cost of assets
C	Defines a generic upper bound for the present value costs and the risk cost of assets
D	Represents a combination of variables that maximises the net market benefits compared to the risk cost of assets

Source: Powercor

The variables and combination of inputs for each scenario are shown in table 4.2.

Table 4.2 Variables used for each scenario

Scenario	Probability of failure	Capital expenditure	Forecast demand	VCR	Operating expenditure	Environment cost
Base case	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate	Central estimate
A	Lower bound	Upper bound	Lower bound	Lower bound	Upper bound	Lower bound
B	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound	Lower bound
C	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound	Upper bound
D	Upper bound	Lower bound	Upper bound	Upper bound	Lower bound	Upper bound

Source: Powercor

The central values used in the base case come from the CBRM, the risk monetisation assumptions, or are input values used within the annualised cost calculations.

The central value (where appropriate) and variation around this value are set within the risk monetisation model. The values used are shown in table 4.3.

Table 4.3 Sensitivity movements in key risk monetisation elements

Element	Lower	Central	Upper
Probability of failure	-10%	100%	+10%
Capital and operating expenditure	-10%	100%	+10%
Demand	-5%	100%	+5%
VCR	-10%	100%	+10%
Environmental costs	-10%	100%	+10%

Source: Powercor

A RVL transformer no.1

Robinvale zone substation (**RVL**) is served by a sub-transmission line from Red Cliffs terminal station and consists of three 66/22kV 10MVA transformers. It supplies the area of Robinvale and surrounding townships.

This appendix summarises the risk monetisation evaluation for the RVL transformer number one.

A.1 Health index

For transformers, separate health indices are calculated for the transformer and tap-changer components. The two health indices are then combined to produce an overall transformer health index.

A.1.1 Transformer health index

RVL transformer number one is a 66kV, 10MVA transformer manufactured by Brush in 1950. The transformer is one of three at the substation and is operated at up to 70% loading. The transformers are in an enclosure and no adverse environmental conditions have been recorded.

For assets of this type, the average time for the onset of critical degradation is typically 60 years. Taking into account the impact of duty on the transformer, this reduces to 54 years. As this asset is 69 years old (in 2019), it has an initial health index value of 5.5.

Transformer condition

Transformer inspection and test results are used to determine cases where the transformer degradation has progressed sufficiently to result in an increased health index and probability of failure. Transformer condition is assessed through visual inspection, which encompasses oil leakage assessment, external visual inspection results, and dielectric loss angle test results.

No condition results have been recorded against the asset and this leads to a condition factor of 1.0.

Transformer defect history

Defect history is also considered in determining the asset health. For this asset, an average number of defects has been recorded, and this leads to a defect history factor of 1.0.

Transformer generic reliability

Generic reliability issues are captured for transformer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This transformer type is assessed as less reliable than average, leading to a generic reliability factor of 1.05.

Transformer oil tests

The transformer oil condition, dissolved gas analysis, and furan analysis results reflect deterioration or electrical degradation of the transformer internal insulation. Measurements are weighted to reflect the extent of the degradation signified by the result.

In the case of this transformer, the oil condition shows some degradation resulting in an oil condition modifier of 1.05. The oil within this transformer has been replaced in the past during remediation, so the furan level will be lower than it might otherwise be. Both the dissolved gas analysis, and furan analysis condition modifiers are 1.0.

Transformer component health index

The combined output of the initial health index, condition, oil test results, defect history and generic reliability provides a health index for the transformer component. In the case of this transformer, the transformer component health index is 6.06.

A.1.2 Tap-changer component health index

The tap-changer associated with the transformer was manufactured by Fuller in 1950. The tap-changer operates on average 2,200 times per year, which is considered an average duty. For assets of this type, duty and localised environment, an average life of 60 years is expected. As this asset is 69 years old it has an initial health index value of 5.5.

Tap-changer condition

Tap-changer inspection results are used to determine cases where the degradation has progressed sufficiently to result in an increased health index and probability of failure. For this asset, no condition results have been recorded and this leads to a condition factor of 1.0.

Tap-changer defect history

In the case of this tap-changer no defects have been recorded against the asset, resulting in a defect history factor of 1.0.

Tap-changer generic reliability

Generic reliability issues are captured for tap-changer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This tap-changer type does not have any reliability issues and this leads to a generic reliability factor of 1.0.

Tap-changer component health index

The combined output of the initial health index, condition, defect history and reliability produces a health index for the tap-changer component. In the case of this transformer, the tap-changer component health index is 5.5.

A.1.3 Combined current health index

The combined health index for this transformer is 6.06. This is driven by the transformer component and reflects the age and reliability concerns for the asset.

A.2 Probability of failure

The current health index of 6.06 in 2019 is projected forward to derive future health indices in accordance with the approach described in section 2.1. The probability of failure for the RVL transformer number one, based on these projections, is shown in table A.1.

Table A.1 RVL transformer number one: probability of failure values (%)

Failure mode	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Catastrophic	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.12	0.13
Major	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.12	0.13
Significant	11.92	12.67	13.46	14.31	15.22	16.19	17.22	18.33	19.51	20.77	22.12	23.56

Source: Powercor

A.3 Consequences of failure

A summary of the consequence of failure for each failure mode, for the RVL transformer number one, is set out in tables A.2, A.3 and A.4. Further detail is provided in the attached RVL risk monetisation model.[5]

Table A.2 RVL transformer number one: catastrophic failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	17.70	20%	3.54
Safety consequence	0.03	20%	0.01
Temporary generators and associated costs	16.59	20%	3.32
Cost of replacement transformers	11.65	20%	2.33
Environmental consequence	2.57	20%	0.51
Fire brigade attendance	0.05	20%	0.01

Source: Powercor

Table A.3 RVL transformer number one: major failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.97	76%	0.74
Safety consequence	0.03	80%	0.02
Temporary generators and associated costs	1.12	80%	0.89
Cost of replacement transformers	3.88	80%	3.11
Environmental consequence	0.87	80%	0.69
Fire brigade attendance	0.05	80%	0.04
Coincident outage risk	11.62	4%	0.46

Source: Powercor

5 PAL MOD 4.13 - RVL transformer no.1 - Jan2020 - Public

Table A.4 RVL transformer number one: significant failure risk: consequence of failure ($ million, 2021)

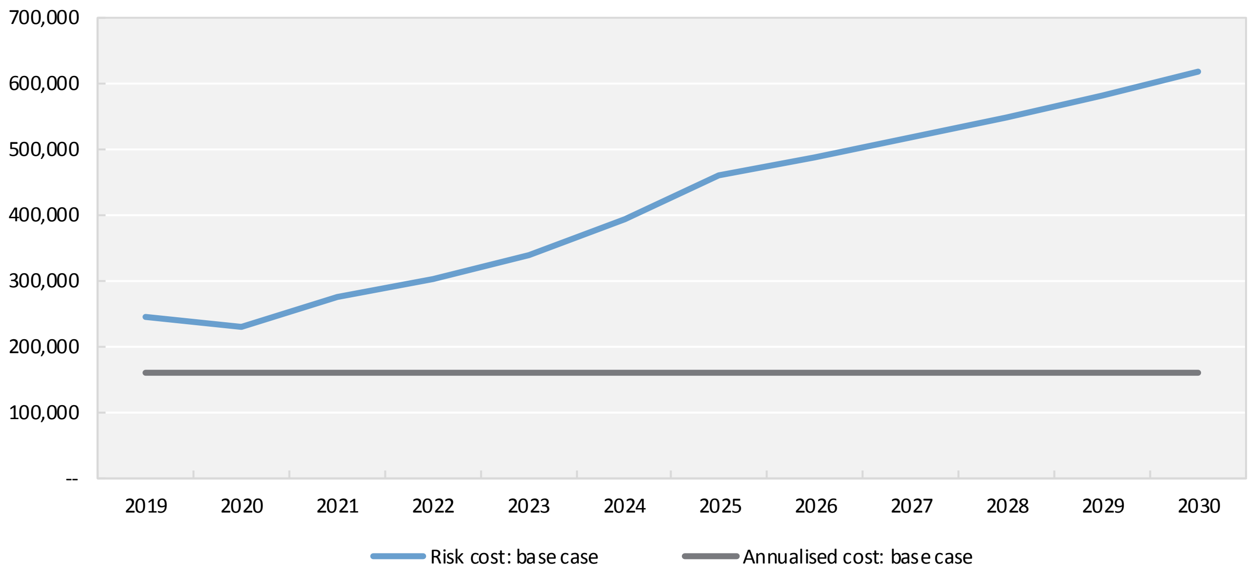
Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.97	96%	0.93
Safety consequence	0.01	100%	0.01
Temporary generators and associated costs	0.27	100%	0.27
Cost of replacement transformers	0.03	100%	0.03
Environmental consequence	0.06	100%	0.06
Fire brigade attendance	0.05	100%	0.05
Coincident outage risk	8.43	4%	0.34

Source: Powercor

A.4 Optimal timing of asset replacement

The optimal timing of asset replacement is based on a comparison of the asset risk and the annualised cost of the preferred option. Figure A.1 shows this comparison for the base case scenario, which reflects our central input assumptions.

Figure A.1 RVL transformer number one: comparison of asset risk and annualised cost for base case ($2021)



Source: Powercor

Under the base case scenario, the annual asset risk cost is higher than the annualised replacement cost from 2019 onwards, so the optimum time to commission the replacement transformer is 2019. This is driven by the asset probability of failure, but also by the high substation loading which would result in the loss of supply and the need for generation in order to restore supplies in the event of a significant or major failure.

The results of the sensitivity analysis for the other four scenarios are shown in table A.5.

Table A.5 RVL transformer number one: summary of sensitivity analysis

Scenario	Optimum timing
Base case	2019
Scenario A	2021/22
Scenario B	2020/21
Scenario C	2019
Scenario D	2019

Source: Powercor

B RVL transformer no.2

Robinvale zone substation (**RVL**) is served by a sub-transmission line from Red Cliffs terminal station and consists of three 66/22kV 10MVA transformers. It supplies the area of Robinvale and surrounding townships.

This appendix summarises the risk monetisation evaluation for the RVL transformer number two.

B.1 Health index

For transformers, separate health indices are calculated for the transformer and tap-changer components. The two health indices are then combined to produce an overall transformer health index.

B.1.1 Transformer health index

RVL transformer number two is a 66kV, 10MVA transformer manufactured by Brush in 1950. The transformer is one of three at the substation and is operated at up to 70% loading. The transformers are in an enclosure and no adverse environmental conditions have been recorded.

For assets of this type, the average time for the onset of critical degradation is typically 60 years. Taking into account the impact of duty on the transformer, this reduces to 54 years. As this asset is 69 years old (in 2019), it has an initial health index value of 5.5.

Transformer condition

Transformer inspection and test results are used to determine cases where the transformer degradation has progressed sufficiently to result in an increased health index and probability of failure. Transformer condition is assessed through visual inspection, which encompasses oil leakage assessment, external visual inspection results, and dielectric loss angle test results.

No condition results have been recorded against the asset and this leads to a condition factor of 1.0.

Transformer defect history

Defect history is also considered in determining the asset health. For this asset, an average number of defects has been recorded, and this leads to a defect history factor of 1.0.

Transformer generic reliability

Generic reliability issues are captured for transformer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This transformer type is assessed as less reliable than average, leading to a generic reliability factor of 1.05.

Transformer oil tests

The transformer oil condition, dissolved gas analysis, and furan analysis results reflect deterioration or electrical degradation of the transformer internal insulation. Measurements are weighted to reflect the extent of the degradation signified by the result.

In the case of this transformer, the oil condition shows some degradation resulting in an oil condition modifier of 1.05. The oil within this transformer has been replaced in the past during remediation, so the furan level will be lower than it might otherwise be. Both the dissolved gas analysis, and furan analysis condition modifiers are 1.0.

Transformer component health index

The combined output of the initial health index, condition, oil test results, defect history and generic reliability provides a health index for the transformer component. In the case of this transformer, the transformer component health index is 6.06.

B.1.2 Tap-changer component health index

The tap-changer associated with the transformer was manufactured by Fuller in 1950. The tap-changer operates on average 2,200 times per year, which is considered an average duty. For assets of this type, duty and localised environment, an average life of 60 years is expected. As this asset is 69 years old it has an initial health index value of 5.5.

Tap-changer condition

Tap-changer inspection results are used to determine cases where the degradation has progressed sufficiently to result in an increased health index and probability of failure. For this asset, no condition results have been recorded and this leads to a condition factor of 1.0.

Tap-changer defect history

In the case of this tap-changer no defects have been recorded against the asset, resulting in a defect history factor of 1.0.

Tap-changer generic reliability

Generic reliability issues are captured for tap-changer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This tap-changer type does not have any reliability issues and this leads to a generic reliability factor of 1.0.

Tap-changer component health index

The combined output of the initial health index, condition, defect history and reliability produces a health index for the tap-changer component. In the case of this transformer, the tap-changer component health index is 5.5.

B.1.3 Combined current health index

The combined health index for this transformer is 6.06. This is driven by the transformer component and reflects the age and reliability concerns for the asset.

B.2 Probability of failure

The current health index of 6.06 in 2019 is projected forward to derive future health indices in accordance with the approach described in section 2.1. The probability of failure for the RVL transformer number two, based on these projections, is shown in table B.1.

Table B.1 RVL transformer number two: probability of failure values (%)

Failure mode	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Catastrophic	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.12	0.13
Major	0.06	0.07	0.07	0.08	0.08	0.09	0.09	0.10	0.10	0.11	0.12	0.13
Significant	11.92	12.67	13.46	14.31	15.22	16.19	17.22	18.33	19.51	20.77	22.12	23.56

Source: Powercor

B.3 Consequences of failure

A summary of the consequence of failure for each failure mode, for the RVL transformer number two, is set out in tables B.2, B.3 and B.4. Further detail is provided in the attached RVL risk monetisation model.[6]

Table B.2 RVL transformer number two: catastrophic failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	17.70	20%	3.54
Safety consequence	0.03	20%	0.01
Temporary generators and associated costs	16.59	20%	3.32
Cost of replacement transformers	11.65	20%	2.33
Environmental consequence	2.57	20%	0.51
Fire brigade attendance	0.05	20%	0.01

Source: Powercor

Table B.3 RVL transformer number two: major failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.97	76%	0.74
Safety consequence	0.03	80%	0.02
Temporary generators and associated costs	1.12	80%	0.89
Cost of replacement transformers	3.88	80%	3.11
Environmental consequence	0.87	80%	0.69
Fire brigade attendance	0.05	80%	0.04
Coincident outage risk	11.62	4%	0.46

Source: Powercor

6 PAL MOD 4.14 - RVL transformer no.2 - Jan2020 - Public

Table B.4 RVL transformer number two: significant failure risk: consequence of failure ($ million, 2021)

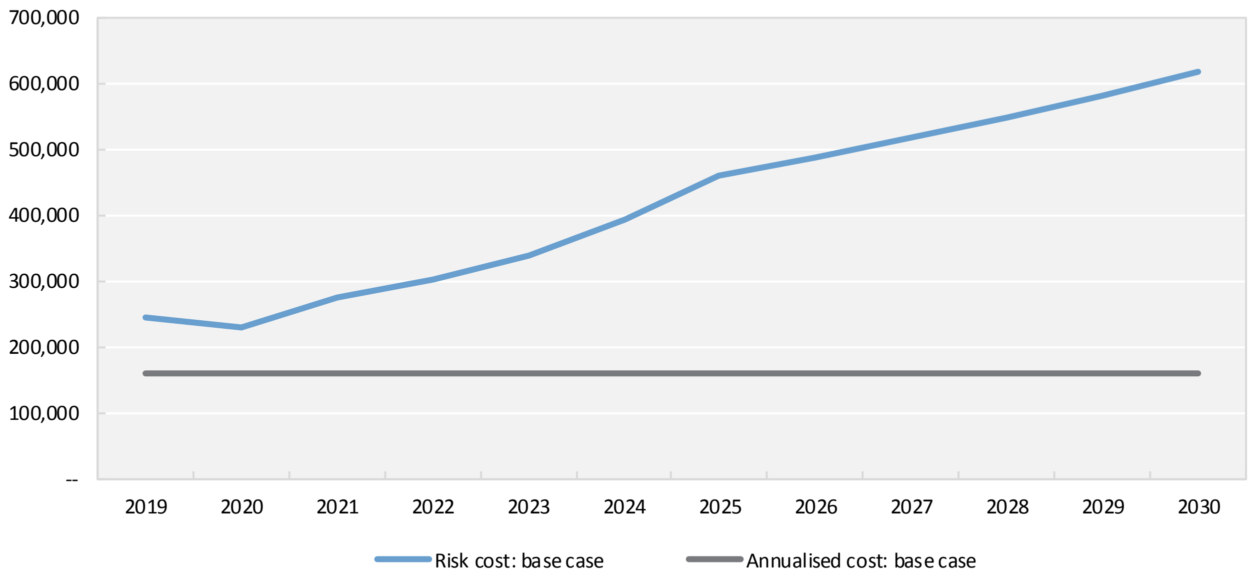
Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.97	96%	0.93
Safety consequence	0.01	100%	0.01
Temporary generators and associated costs	0.27	100%	0.27
Cost of replacement transformers	0.03	100%	0.03
Environmental consequence	0.06	100%	0.06
Fire brigade attendance	0.05	100%	0.05
Coincident outage risk	8.43	4%	0.34

Source: Powercor

B.4 Optimal timing of asset replacement

The optimal timing of asset replacement is based on a comparison of the asset risk and the annualised cost of the preferred option. Figure B.1 shows this comparison for the base case scenario, which reflects our central input assumptions.

Figure B.1 RVL transformer number two: comparison of asset risk and annualised cost for base case ($2021)



Source: Powercor

Under the base case scenario, the annual asset risk cost is higher than the annualised replacement cost from 2019 onwards, so the optimum time to commission the replacement transformer is 2019. This is driven by the asset probability of failure, but also by the high substation loading which would result in the loss of supply and the need for generation in order to restore supplies in the event of a significant or major failure.

The results of the sensitivity analysis for the other four scenarios are shown in table B.5.

Table B.5 RVL transformer number two: summary of sensitivity analysis

Scenario	Optimum timing
Base case	2019
Scenario A	2021/22
Scenario B	2020/21
Scenario C	2019
Scenario D	2019

Source: Powercor

C WBL transformer no.3

Warrnambool zone substation (**WBL**) is served by two sub-transmission lines from the Terang (**TRG**) and Koroit (**KRT**) zone substations. The WBL zone substation comprises one 25/33 MVA transformer and two 10/13.5 MVA transformers operating at 66/22kV. It supplies the township of Warrnambool and surrounding areas.

This appendix summarises the risk monetisation evaluation for the WBL transformer number three.

C.1 Health index

For transformers, separate health indices are calculated for the transformer and tap-changer components. The two health indices are then combined to produce an overall transformer health index.

C.1.1 Transformer health index

WBL transformer number three is a 66kV 13.5MVA transformer manufactured by GEC/AEI in 1948. The transformer is one of three at the substation and is operated at up to 84% loading. The transformers are outdoors and no adverse environmental conditions have been recorded.

For assets of this type, the average time for the onset of critical degradation is typically 60 years. Taking into account the impact of duty on the transformer, this reduces to 54 years. As this asset is 71 years old (in 2019), it has an initial health index value of 5.5.

Transformer condition

Transformer inspection and test results are used to determine cases where the transformer degradation has progressed sufficiently to result in an increased health index and probability of failure. Transformer condition is assessed through visual inspection, which encompasses oil leakage assessment, external visual inspection results, and dielectric loss angle test results.

No condition results have been recorded against the asset and this leads to a condition factor of 1.0.

Transformer defect history

Defect history is also considered in determining the asset health. For this asset, an above average number of defects has been recorded, and this leads to a defect history factor of 1.05.

Transformer generic reliability

Generic reliability issues are captured for transformer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This transformer type is assessed as less reliable than average, leading to a generic reliability factor of 1.05.

Transformer oil tests

The transformer oil condition, dissolved gas analysis, and furan analysis results reflect deterioration or electrical degradation of the transformer internal insulation. Measurements are weighted to reflect the extent of the degradation signified by the result.

In the case of this transformer, the oil condition shows some degradation resulting in an oil condition modifier of 1.05. There are slightly elevated (and increasing) levels of ethylene resulting in a dissolved gas analysis condition modifier of 1.5. The furan levels are low, giving a furan analysis modifier of 1.0.

Transformer component health index

The combined output of the initial health index, condition, oil test results, defect history and generic reliability provides a health index for the transformer component. In the case of this transformer, the transformer component health index is 9.48.

C.1.2 Tap-changer component health index

The tap-changer associated with the transformer was manufactured by AEI in 1948. The tap-changer operates on average 5,200 times per year, which is considered an above average duty. For assets of this type, duty and localised environment, an average life of 60 years is expected. As this asset is 71 years old it has an initial health index value of 5.5.

Tap-changer condition

Tap-changer inspection results are used to determine cases where the degradation has progressed sufficiently to result in an increased health index and probability of failure. For this asset, no condition results have been recorded and this leads to a condition factor of 1.0.

Tap-changer defect history

In the case of this tap-changer no defects have been recorded against the asset, resulting in a defect history factor of 1.0.

Tap-changer generic reliability

Generic reliability issues are captured for tap-changer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This tap-changer type does not have any reliability issues and this leads to a generic reliability factor of 1.0.

Tap-changer component health index

The combined output of the initial health index, condition, defect history and reliability produces a health index for the tap-changer component. In the case of this transformer, the tap-changer component health index is 5.5.

C.1.3 Combined current health index

The combined health index for this transformer is 9.48. This is driven by the transformer component and reflects the age, defect history, reliability concerns and recent dissolved gas analysis results for the asset.

C.2 Probability of failure

The current health index of 9.48 in 2019 is projected forward to derive future health indices in accordance with the approach described in section 2.1. The probability of failure for the WBL transformer number three, based on these projections, is shown in table C.1.

Table C.1 WBL transformer number three: probability of failure values (%)

Failure mode	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Catastrophic	0.21	0.22	0.24	0.26	0.28	0.30	0.32	0.35	0.37	0.40	0.44	0.47
Major	0.21	0.22	0.24	0.26	0.28	0.30	0.32	0.35	0.37	0.40	0.44	0.47
Significant	38.16	41.11	44.30	47.74	51.47	55.49	59.85	64.56	69.65	75.16	81.12	87.55

Source: Powercor

C.3 Consequences of failure

A summary of the consequence of failure for each failure mode, for the WBL transformer number three, is set out in tables C.2, C.3 and C.4. Further detail is provided in the attached WBL risk monetisation model.[7]

Table C.2 WBL transformer number three: catastrophic failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	41.08	20%	8.22
Safety consequence	0.03	20%	0.01
Temporary generators and associated costs	31.14	20%	6.23
Cost of replacement transformers	11.65	20%	2.33
Environmental consequence	2.57	20%	0.51
Fire brigade attendance	0.05	20%	0.01

Source: Powercor

Table C.3 WBL transformer number three: major failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	-	76%	-
Safety consequence	0.03	80%	0.02
Temporary generators and associated costs	-	80%	-
Cost of replacement transformers	3.88	80%	3.11
Environmental consequence	0.87	80%	0.69
Fire brigade attendance	0.05	80%	0.04
Coincident outage risk	23.53	4%	0.94

Source: Powercor

[7] PAL MOD 4.05 - WBL transformer no.3 - Jan2020 - Public

Table C.4 WBL transformer number three: significant failure risk: consequence of failure ($ million, 2021)

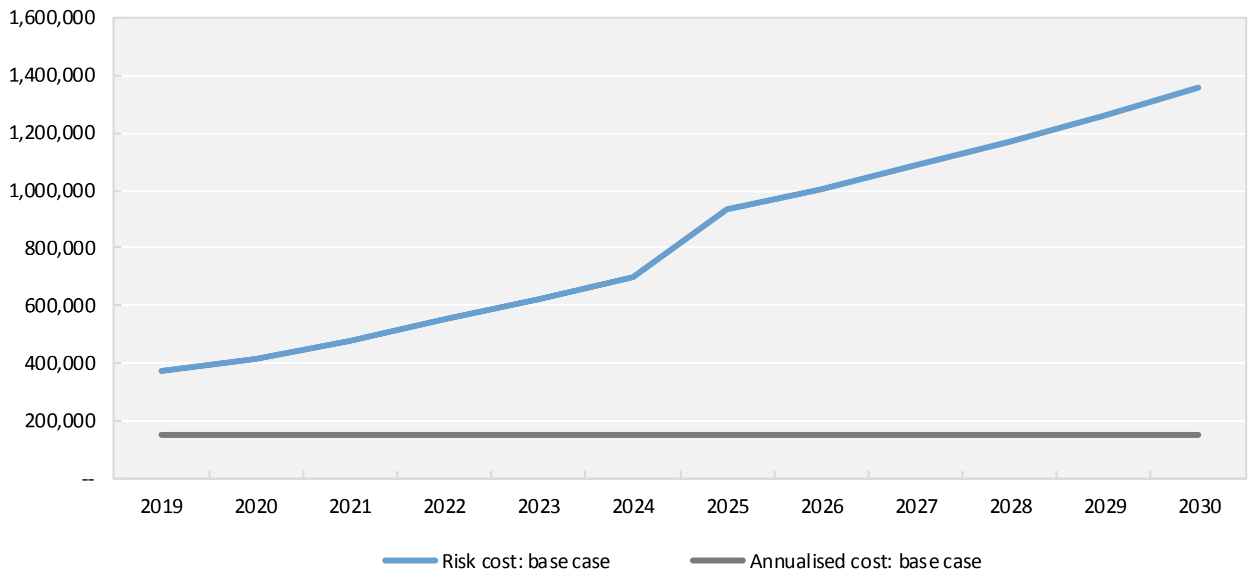
Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	-	96%	-
Safety consequence	0.01	100%	0.01
Temporary generators and associated costs	-	100%	-
Cost of replacement transformers	0.02	100%	0.02
Environmental consequence	0.06	100%	0.06
Fire brigade attendance	0.05	100%	0.05
Coincident outage risk	16.73	4%	0.67

Source: Powercor

C.4 Optimal timing of asset replacement

The optimal timing of asset replacement is based on a comparison of the asset risk and the annualised cost of the preferred option. Figure C.1 shows this comparison for the base case scenario, which reflects our central input assumptions.

Figure C.1 WBL transformer number three: comparison of asset risk and annualised cost for base case ($2021)



Source: Powercor

Under the base case scenario, the annual asset risk cost is higher than the annualised replacement cost from 2019 onwards, so the optimum time to commission the replacement transformer is 2019. This is driven by the asset probability of failure, but also by the high substation loading which would result in the loss of supply and the need for generation in order to restore supplies in the event of a significant or major failure.

The results of the sensitivity analysis for the other four scenarios are shown in table C.5. This analysis indicates that under all scenarios, the optimum time to replace the transformer is 2019.

Table C.5 WBL transformer number three: summary of sensitivity analysis

Scenario	Optimum timing
Base case	2019
Scenario A	2019
Scenario B	2019
Scenario C	2019
Scenario D	2019

Source: Powercor

D IWD regulator

Inglewood regulator (**IWD**) is a 66/66kV regulator being from Bendigo and regulating voltage to Charlton (**CTN**) zone substation.

This appendix summarises the risk monetisation evaluation for the IWD regulator.

D.1 Health index

For regulators, separate health indices are calculated for the regulator and tap-changer components. The two health indices are then combined to produce an overall regulator health index.

D.1.1 Regulator health index

IWD regulator is a 66kV regulator manufactured by GEC/AEI in 1941. The regulator is located at the CTN zone substation.

For assets of this type, the average time for the onset of critical degradation is typically 60 years. There is no duty or location data for this asset, and hence, the expected life is 60 years. As this asset is 78 years old (in 2019), it has an initial health index value of 5.5.

Regulator condition

Regulator inspection and test results are used to determine cases where the regulator degradation has progressed sufficiently to result in an increased health index and probability of failure. Regulator condition is assessed through visual inspection and dielectric loss angle test results.

No condition results have been recorded against the asset and this leads to a condition factor of 1.0.

Regulator defect history

Defect history is also considered in determining the asset health. For this asset, an average number of defects has been recorded, and this leads to a defect history factor of 1.0.

Regulator generic reliability

Generic reliability issues are captured for regulator types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This regulator type is assessed as less reliable than average, leading to a generic reliability factor of 1.10.

Regulator oil tests

The regulator oil condition, dissolved gas analysis, and furan analysis results reflect deterioration or electrical degradation of the transformer internal insulation. Measurements are weighted to reflect the extent of the degradation signified by the result.

In the case of this regulator, the dissolved gas analysis results shows some degradation, but not sufficient to increase the asset health index. The dissolved gas and furan analysis modifiers are 1.0.

Regulator component health index

The combined output of the initial health index, condition, oil test results, defect history and generic reliability provides a health index for the regulator component. In the case of this regulator, the regulator component health index is 7.0.

D.1.2 Tap-changer component health index

The tap-changer associated with the regulator was manufactured by GEC in 1941. The tap-changer operates on average 200 times per year, which is considered a light duty. For assets of this type, duty and localised environment, an average life of 60 years is expected. As this asset is 78 years old it has an initial health index value of 5.5.

Tap-changer condition

Tap-changer inspection results are used to determine cases where the degradation has progressed sufficiently to result in an increased health index and probability of failure. For this asset, no condition results have been recorded and this leads to a condition factor of 1.0.

Tap-changer defect history

In the case of this tap-changer, an average number of defects have been recorded, resulting in a defect history factor of 1.0.

Tap-changer generic reliability

Generic reliability issues are captured for tap-changer types considered to be less reliable than most of the population. This is based on actual performance of the assets within our network.

This tap-changer type does not have any reliability issues and this leads to a generic reliability factor of 1.0.

Tap-changer component health index

The combined output of the initial health index, condition, defect history and reliability produces a health index for the tap-changer component. In the case of this transformer, the tap-changer component health index is 5.5.

D.1.3 Combined current health index

The combined health index for this transformer is 7.0.

D.2 Probability of failure

The current health index of 7.0 in 2019 is projected forward to derive future health indices in accordance with the approach described in section 2.1. The probability of failure for the IWD regulator, based on these projections, is shown in table D.1.

Table D.1 IWD regulator: probability of failure values (%)

Failure mode	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Catastrophic	0.09	0.10	0.10	0.11	0.12	0.12	0.13	0.14	0.15	0.16	0.17	0.18
Major	0.09	0.10	0.10	0.11	0.12	0.12	0.13	0.14	0.15	0.16	0.17	0.18
Significant	17.17	18.20	19.30	20.46	21.70	23.02	24.43	25.92	27.51	29.21	31.01	32.93

Source: Powercor

D.3 Consequences of failure

A summary of the consequence of failure for the major and significant failure modes, for the IWD regulator, is set out in tables D.2 and D.3 (a catastrophic failure mode was not considered for this asset). Further detail is provided in the attached IWD risk monetisation model.[8]

Table D.2 IWD regulator: major failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.45	96%	0.43
Safety consequence	0.03	100%	0.03
Temporary generators and associated costs	-	100%	-
Cost of replacement regulator	1.26	100%	1.26
Environmental consequence	0.87	100%	0.87
Fire brigade attendance	0.05	100%	0.05
Coincident outage risk	20.01	4%	0.80

Source: Powercor

Table D.3 IWD regulator: significant failure risk: consequence of failure ($ million, 2021)

Description	Total risk value	Likelihood of consequence	Cost of consequence
Expected average unserved energy	0.45	96%	0.43
Safety consequence	0.01	100%	0.01
Temporary generators and associated costs	-	100%	-
Cost of replacement regulator	0.01	100%	0.01
Environmental consequence	0.06	100%	0.06
Fire brigade attendance	0.05	100%	0.05
Coincident outage risk	14.80	4%	0.59

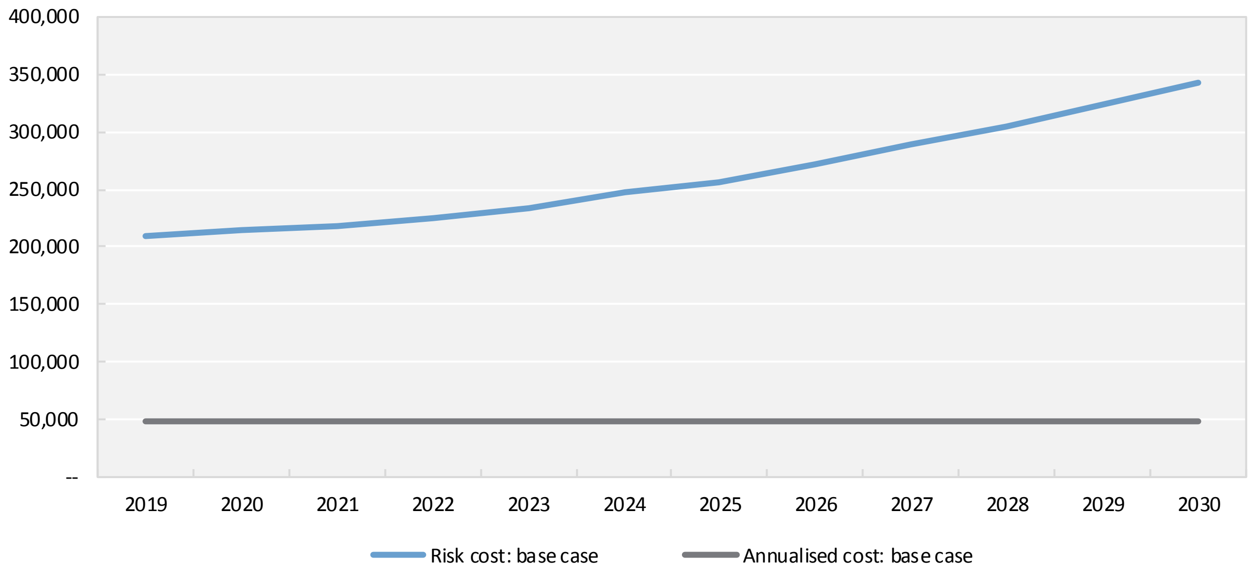
Source: Powercor

8 PAL MOD 4.12 - IWD regulator - Jan2020 - Public

D.4 Optimal timing of asset replacement

The optimal timing of asset replacement is based on a comparison of the asset risk and the annualised cost of the preferred option. Figure D.1 shows this comparison for the base case scenario, which reflects our central input assumptions.

Figure D.1 IWD regulator: comparison of asset risk and annualised cost for base case ($2021)



Source: Powercor

Under the base case scenario, the annual asset risk cost is higher than the annualised replacement cost from 2019 onwards, so the optimum time to commission the replacement regulator is 2019.

The results of the sensitivity analysis for the other four scenarios are shown in table D.4. This analysis indicates that under all scenarios, the optimum time to replace the regulator is 2019.

Table D.4 IWD regulator: summary of sensitivity analysis

Scenario	Optimum timing
Base case	2019
Scenario A	2019
Scenario B	2019
Scenario C	2019
Scenario D	2019

Source: Powercor