Managing asset risks in the St George network area

DRAFT PROJECT ASSESSMENT REPORT

18 SEPTEMBER 2018

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Managing Asset Risks in the St George network area

Draft Project Assessment Report – September 2018

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Executive Summary

This report investigates the most economic option for continuing efficient supply to the St George network area

This Draft Project Assessment Report (DPAR) has been prepared by Ausgrid and represents the first step in the application of the Regulatory Investment Test for Distribution (RIT-D) to options for managing asset risks in the St George network area going forward.

In particular, the St George 33kV subtransmission network is supplied from only one subtransmission substation (STS), which is located at Peakhurst. This STS was commissioned in 1964 and has asset condition and safety concerns stemming from obsolete 33kV switchgear, located in a switchroom building that is non-compliant with contemporary Building Code of Australia (BCA) standards and without adequate segregation in the event of equipment failure. If left unaddressed, these assets are forecast to become less reliable, leading to increasing safety risks to Ausgrid's staff, customers and the general public, along with increasing risks of exceeding allowable levels under the applicable reliability standards.

Ausgrid considers that reliability correction action is required for Peakhurst STS to comply with its electricity distribution license reliability and performance standards.

Ausgrid has prepared this report in response to recent Rules changes requiring the RIT-D to be applied to replacement expenditure

Rule changes to the National Electricity Rules (NER) in July 2017 have meant that replacement capital expenditure, such as the one proposed in this DPAR, are now subject to the RIT-D. Accordingly, Ausgrid has initiated this RIT-D for the Peakhurst STS replacement project in order to identify a preferred option that would ensure Ausgrid is able to satisfy its reliability and performance standards in supplying the St George network area.

Two credible options have been assessed to address reliability concerns

Ausgrid has identified two network options that either refurbish the 33kV switchgear building in situ (i.e. a 'brownfield development'), or construct a new 33kV switchgear building and retire existing 33kV buildings (i.e. a 'greenfield development').

The two credible options are summarised below.

Table E.1 – Summary of the credible options considered

Network option	Estimated capital cost ($2018/19)
Option 1 – Brownfield development	$22.1 million + $0.5 million (decommissioning costs)
Option 2 – Greenfield development	$20.1 million + $2.0 million (decommissioning costs)

Option 1 is more expensive due to the complexities of staged construction next to energised equipment. It is also the option more exposed to higher risk of unforeseen costs.

Ausgrid also considered retirement of the 33kV switchgear and associated equipment of Peakhurst STS, but was found to be non-credible as there are no other viable options of maintaining ongoing supply to the St George area.

Non-network options are not considered viable for this RIT-D

Ausgrid has also considered the ability of any non-network solutions to assist in meeting the identified need. As the driver for this replacement investment is largely the need to manage safety risks at the site, a demand management assessment into reducing the unserved energy has determined that non-network alternatives cannot cost-effectively address the risk, compared to the network options outlined above. Therefore non-network solutions are unlikely to form a standalone credible option, or form a significant part of a credible option, as set out in the separate notice released in accordance with clause 5.17.4(d) of the NER

If during the course of this RIT-D process, a cost-effective non-network solution emerges, then it will be assessed alongside the other options.

Three different 'scenarios' have been modelled to deal with uncertainty

Ausgrid has elected to assess three alternative future scenarios – namely:

- Low benefit scenario – Ausgrid has adopted a number of assumptions that give rise to a lower bound NPV estimate for each credible option, in order to represent a conservative future state of the world with respect to potential market benefits that could be realised under each credible option;
- Baseline scenario – the baseline scenario consists of assumptions that reflect Ausgrid's central set of variable estimates, which, in Ausgrid's opinion, provides the most likely scenario; and
- High benefit scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected potential market benefits.

Given that no non-network options have been found to be viable, Ausgrid considers the appropriate discount rate to be 4.19 per cent, equal to the latest AER Final decision for a DSNP's regulatory proposal at the time of preparing this DPAR[1].

Table E.2 – Summary of the three scenarios investigated

Variable	Scenario 1 – low benefits	Scenario 2 – baseline	Scenario 3 – high benefits
Capital cost	110 per cent of capital cost estimate for greenfield and 130 per cent for brownfield	100 per cent of capital cost estimate	90 per cent of capital cost estimate
Demand	POE90	POE50	POE10
VCR	$29/kWh (30 per cent lower than the central, AEMO-derived estimate)	$41/kWh (Derived from the AEMO VCR estimates)	$53/kWh (30 per cent higher than the central, AEMO-derived estimate)
Safety risk cost	70 per cent of baseline estimate	100 per cent of baseline estimate	130 per cent of baseline estimate
Unplanned corrective maintenance cost	70 per cent of baseline estimate	100 per cent of baseline estimate	130 per cent of baseline estimate

Option 2 has the highest expected net market benefits, under all scenarios

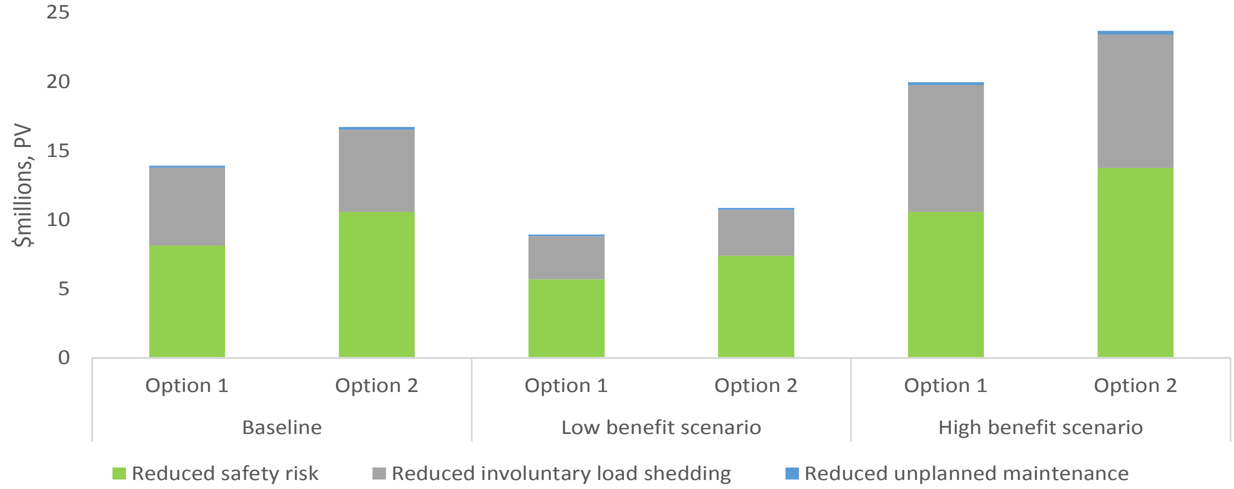
Expected benefits are largely driven by the value of avoided costs associated with safety, by mitigating the risk of potential injuries/fatalities to Ausgrid staff and general public.

The two options are found to have similar overall benefit, as these options are assumed to be commisioned only two years apart and therefore avoid similar levels of safety risk costs and expected unserved energy.

On a weighted present value basis, Option 2 is expected to provided approximately $2.8 million more gross benefits arising from two additional years of benefits in 2021/22 and 2022/23 compared to Option 1.

[1] See TasNetworks' PTRM for the 2017-19 period, available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2017-2019/final-decision

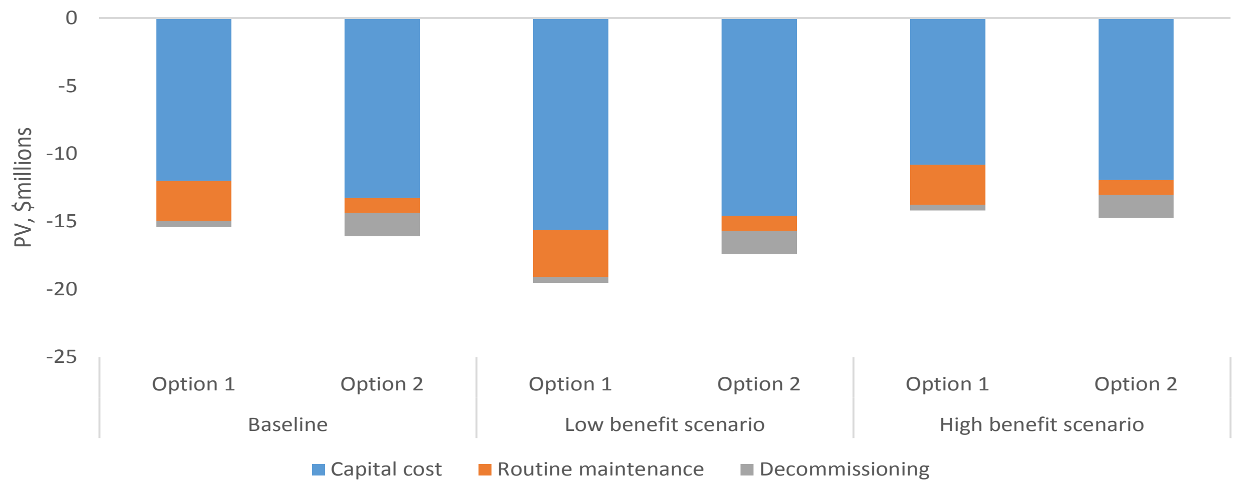
Figure E-1 – Breakdown of gross economic benefits of each credible option relative to the base case



The figure below provides a breakdown of costs relating to each credible option. Capital costs are the determining factor for the ranking of credible options considered.

The two options have similar costs under all scenarios in present value terms, noting that Option 1 has higher routine maintenance costs associated with keeping the existing buildings in service, and that Option 2 involves higher decommissioning costs arising from demolition costs associated with the existing substation zone buildings.

Figure E-2 – Present value of costs of each credible option relative to the base case



The table below summarises the net market benefit in NPV terms for each credible option under each scenario. The net market benefit is the gross market benefit minus the cost of each option, all in present value terms.

Overall, Option 2 exhibits the highest estimated net market benefit, which is driven primarily by it having the lowest capital cost and two more years of market and avoided cost benefits out of the two credible options considered.

Table E.3 – Net Present Value of credible options relative to the base case, $m 2018/19[2]

Option	Capital costs	Operating costs	Weighted PV of gross benefits	Weighted PV of net benefits	Option ranking
Option 1	-12.6	-3.5	14.2	-1.9	2
Option 2	-13.3	-2.8	17.0	0.9	1

The results have been sensitivity tested and Option 2 is consistently the preferred option.

[2] Figures in Table E.3 may not add due to rounding.

Option 2 is the preferred option at this draft stage

Option 2 has found to be the preferred option, which involves the construction of a new 33kV switchroom, installation of new 33kV switchgear and the retirement of the existing 33kV switchgear and associated buildings.

Specifically, the scope of the greenfield development involves:

- construction of a new building to be located on the existing substation site;
- installation and commissioning of three sections of new 33kV switchgear;
- installation of new control and protection for the new 33kV switchgear, as well as local 132kV control and protection and a new distributed SCADA system; and
- installation of underground XLPE cable connections to transfer the 33kV feeders to the new 33kV switchgear.

The estimated cost of this option is approximately $20.1 million with a further $2.0 million for decommissioning costs. Ausgrid assumes the greenfield development would commence in 2018/19 with the replacement scheduled to be commissioned in 2021/22 and subsequent decommissioning of the aged network assets in 2022/23. Once the replacement is complete, operating costs are expected to be approximately $100,000 per annum (around 0.5 per cent of capital expenditure).

Ausgrid considers that this DPAR, and the accompanying detailed analysis, identify Option 2 as the preferred option and that this satisfies the RIT-D. Ausgrid is the proponent for Option 2.

How to make a submission and next steps

Ausgrid welcomes written submissions on this DPAR. Submissions are due on or before 30 October 2018. Submissions and queries should be addressed to:

Matthew Webb
Head of Asset Investment
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GPO Box 4009
Sydney 2001

Or

email to: assetinvestment@ausgrid.com.au

Submissions will be published on the Ausgrid website. If you do not want your submission to be publicly available please clearly stipulate this at the time of lodgement.

The next step of this RIT-D involves publication of a Final Project Assessment Report (FPAR). The FPAR will update the assessment of the net benefit associated with different investment options, in light of any submissions received on this DPAR. Ausgrid intends to publish the FPAR as soon as practicable after submissions are received on this DPAR

1 Introduction

This Draft Project Assessment Report (DPAR) has been prepared by Ausgrid and represents the first step in the application of the Regulatory Investment Test for Distribution (RIT-D) to options for managing asset risks in the St George network area going forward.

In particular, the entire St George 33kV subtransmission network is supplied primarily from only one subtransmission substation (STS), which is located at Peakhurst. This STS was commissioned in 1964 and is equipped with three 132/33kV 120 MVA transformers (two of which are in service currently, while the third is on standby) and four sections of 33kV switchgear. It currently supplies five 33/11kV zone substations in the area – Arncliffe, Blakehurst, Mortdale, Riverwood and Sans Souci.

While one of the existing 33/11kV substations in the St George area will be retired in coming years (i.e. Arncliffe), which will reduce Peakhurst STS load from 2019 onwards, as reflected in maximum demand forecasts, there is an enduring need for the Peakhurst STS and there are fundamental asset condition issues identified. Specifically, the 33kV switchroom and control buildings are in poor condition and most of the 33kV switchgear equipment is at end of its service life.

In addition, there are a number of 33kV bulk oil circuit breakers, the failure modes of which impose an unacceptable safety risk that could result in a failure of the inner switchroom doors, walls or roof panels (and, ultimately a fire at the STS). Although the existing 33kV circuit breakers are outdoor bulk oil-type, they have been installed in enclosed rooms, a common practice by the NSW Electricity Commission in the 1960s, which means that replacing them with modern equivalent circuit breakers in the existing building and enclosures while maintaining electrical clearances is not feasible.

Ausgrid identified the need to address the deteriorating assets at the Peakhurst STS in 2013 and identified a preferred solution, which involves constructing a new 33kV switchgear building and retiring the existing 33kV building (i.e. a greenfield development). This solution can be commissioned in 2021/22 and minimise safety and involuntary load shedding earlier than the other option considered. This is possible as a new 33kV switchgear building avoids the complexity of refurbishing legacy assets in a live switchyard, which can be complicated, give rise to additional safety considerations during construction and incur unexpected costs.

Ausgrid has initiated contacts with the community, seeking feedback on the proposed network option. These activities have so far included letters to the neighbourhood explaining the proposed works at Peakhurst STS as well as a letter to the Georges River Council.

Rule changes to the National Electricity Rules (NER) in July 2017 have meant that the replacement plan for the St George area is now subject to the RIT-D. Accordingly, Ausgrid has initiated this RIT-D in order to investigate and consult on options to ensure Ausgrid is able to satisfy the reliability and performance standards that it is obliged to meet.

Ausgrid has determined that non-network solutions are unlikely to form a standalone credible option, or form a significant part of a credible option, as set out in the separate notice released in accordance with clause 5.17.4(d) of the NER.

1.1 Role of this draft report

Ausgrid has prepared this DPAR in accordance with the requirements of the NER under clause 5.17.4. It is the first stage of the formal consultation process set out in the NER in relation to the application of the RIT-D.

The purpose of the DPAR is to:

- describe the identified need Ausgrid is seeking to address, together with the assumptions used in identifying it;
- provide a description of each credible option assessed;
- quantify relevant costs and market benefits for each credible option;
- describe the methodologies used in quantifying each class of cost and market benefit;
- provide reasons why Ausgrid has determined that classes of market benefits or costs do not apply to a credible option(s);
- present the results of a net present value analysis of each credible option and accompanying explanation of the results; and
- identify the proposed preferred option.

The next stage of this RIT-D involves publication of a Final Project Assessment Report (FPAR). The FPAR will update the quantitative assessment of the net benefit associated with different investment options, in light of any submissions received on this DPAR.

The entire RIT-D process is detailed in Appendix B. The next steps for this particular RIT-D assessment are discussed further below.

1.2 Submissions and queries

Ausgrid welcomes written submissions on this DPAR. Submissions are due on or before 30 October 2018. Submissions and queries should be addressed to:

Matthew Webb
Head of Asset Investment
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GPO Box 4009
Sydney 2001

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Submissions will be published on the Ausgrid website. If you do not want your submission to be publicly available please clearly stipulate this at the time of lodgement.

2 Description of the identified need

This section provides a description of the network area and the 'identified need' for this RIT-D, before presenting a number of key assumptions underlying the identified need.

2.1 Overview of the St George area

The St George area extends west from Arncliffe and Sans Souci on Botany Bay, and inland to Peakhurst. The East Hills and Illawarra railway lines, as well as the Princes Highway and planned F6 Freeway extension, pass through the area.

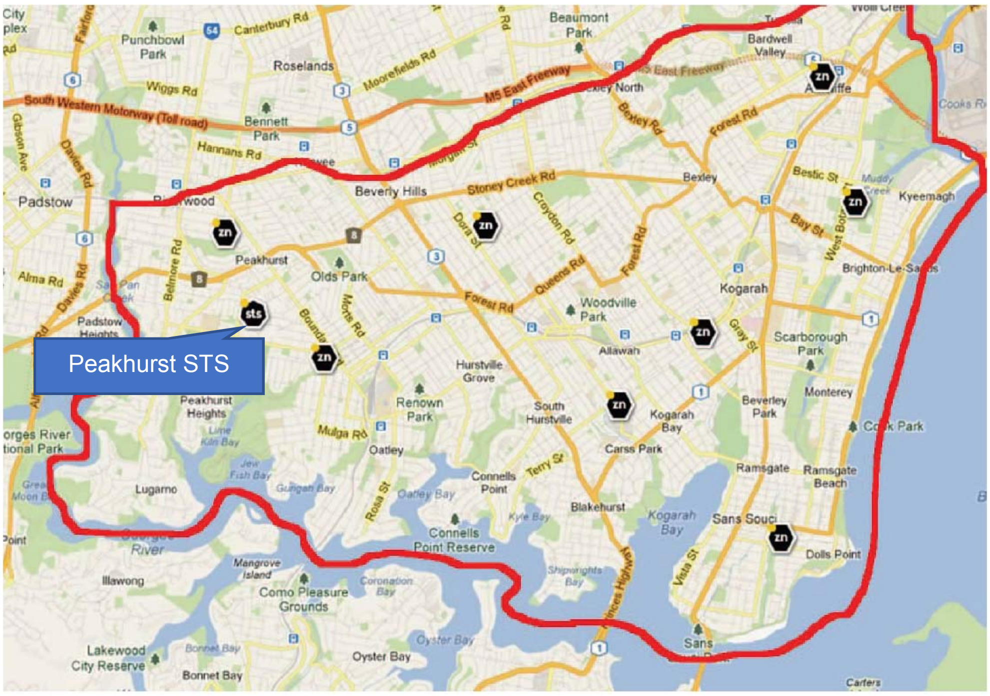
The network in the St George network area:

- is substantively supplied from Peakhurst STS via two 132kV feeders from TransGrid's transmission system at the Sydney South Bulk Supply Point;
- includes five 33/11kV zone substations (Arncliffe, Blakehurst, Mortdale, Riverwood and Sans Souci) and three 132/11kV zone substations (Kogarah, Hurstville North and Rockdale); and
- is traversed by 132kV XLPE cables from Peakhurst to Canterbury and Beaconsfield West.

The St George network is an urban area and includes an increasing number of high density residential developments along with commercial areas such as the Hurstville retail district. As a result, population growth along the rail corridor continues to be the driver behind load growth. Importantly, there are limited opportunities for connection with other areas of the network because of various geographic, network and physical features of the area, including waterways and transport corridors.

The figure below illustrates the geographic region of the St George area network as well as the eight zone substations that service the region (i.e. both the five 33/11kV zone substations and three 132/11kV zone substations) shown by black hexagons. Peakhurst STS is also highlighted in Figure 2-1.

Figure 2-1 – St George network area



The Peakhurst STS was commissioned in 1964. It is equipped with three 132/33kV 120 MVA transformers (two of which are in service currently, while the third is on standby) and four sections of 33kV switchgear. It currently supplies all five of the 33/11kV zone substations in the St George area. Peakhurst STS has a firm rating capacity of 233MVA and a current peak load (summer driven) of 132MVA. However, with the proposed related project of retiring Arncliffe zone substation, Peakhurst STS load will be reduced to 119MVA in 2019.

Despite the reduced load coming into effect from 2019, there are fundamental asset condition issues that have been identified at Peakhurst STS– specifically:

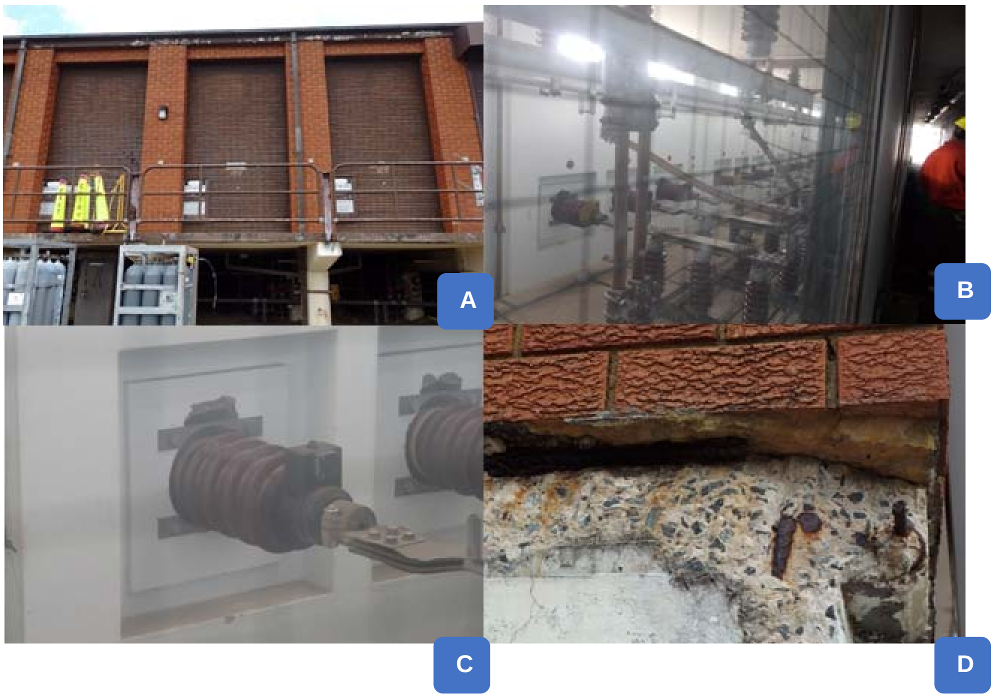
- The 33kV switchroom and control buildings are in poor condition:
    - the existing straw mat ceiling in the 33kV busbar chambers is a flammable material and is in relatively close proximity to live 33kV equipment – when in good condition risks have been manageable, however over time water penetration causes the roofing material to degrade, exposing the electrical equipment to water damage;
    - several beams and piles on the building have spalled concrete and exposed corroded steel reinforcement; and
    - further, in the event of fire, the building's physical structure does not allow contemporary levels of segregation within the switchroom building.
- Most of the 33kV switchgear equipment is at end of its service life:
    - in particular, there have been failures in the 33kV wall bushings as a result of degraded insulation quality; and
    - the 33kV isolators and earth switches are also in poor condition and are an obsolete design, requiring manual operations through a series of mechanical drives and linkages.

In addition, there are number of 33kV bulk oil circuit breakers and the failure modes can result in a failure of the inner switchroom doors, walls or roof panels, and fire leading to an unacceptable safety risks. Although the existing 33kV circuit breakers are outdoor bulk oil-type, they have been installed in enclosed rooms (a common practice by the NSW Electricity Commission in the 1960s), which means that replacing them with modern equivalent circuit breakers in the existing building and enclosures while maintaining electrical clearances is not feasible.

It should also be noted that the building has non-compliance issues with standards established in the Building Code of Australia (BCA). In particular, the switchroom and control room building has inadequate emergency stair cases, stair handrails and exit lighting.

The figure below illustrates the physical condition of key substation equipment at the Peakhurst STS.

Figure 2-2 – Condition of equipment at Peakhurst STS



A: External view of 33kV circuit breaker chambers (no adequate segregation and venting in the event of failure)

B: 33kV busbar gallery above circuit breakers

C: 33kV porcelain wall bushings (with degraded insulation quality)

D: Concrete spalling, control room floor, close-up

Ausgrid believes that there is a window of opportunity to address these issues before they deteriorate further. Timely intervention is critical in avoiding the risk of sudden further deterioration and the need for unplanned intervention, with associated safety hazards, extended unplanned outages and repair times. Ausgrid considers that the modelling presented in this DPAR illustrates this case.

2.2 Overview of Ausgrid's relevant safety and distribution reliability standards

Ausgrid must manage safety risks to ensure that they are eliminated so far as is reasonably practicable (SOFAIRP) or where that is not possible, mitigated to a level which is 'As Low as Reasonably Practicable' ('ALARP'), in accordance with obligations under the New South Wales Electricity Supply (Safety and Network Management) Regulation 2014 and Ausgrid's Safety Management System.

In addition, all New South Wales electricity distribution businesses, including Ausgrid, are obliged to comply with reliability and performance standards as part of their distributor's license.[3] These standards are determined by the New South Wales Government.

At a high-level, the reliability and performance standards are specified in terms of both:

- the average frequency of interruptions a customer may face each year; and
- the average time those outages may last.

Specifically, under the current Ausgrid license, reliability and performance standards are expressed in two measures – namely:

- the System Average Interruption Frequency Index – 'SAIFI' – which measures the number of times on average that customers have their electricity interrupted over the year;[4] and
- the System Average Interruption Duration Index – 'SAIDI' – which measures the total length of time (in minutes) that, on average, a customer would have their electricity supply interrupted over a given period.[5]

These two reliability measures capture two key sources of inconvenience to electricity customers from supply disruptions, i.e. how long their electricity supply is off for as well as how often their electricity supply is off. Customers experience less inconvenience (i.e. a better level of supply reliability), the lower these measures are. Reliability standards applied to distribution networks typically set minimum requirements in relation to each of these two measures.

The current reliability standards applying to the St George network area (classified as an 'urban' feeder type) are shown in the table below.

Table 2.1 – Current distribution reliability standards applying to Ausgrid[6]

Feeder type	Network Overall Reliability Standards		Individual Feeder Reliability Standard	
	SAIDI (Minutes per customer)	SAIFI (Number per customer)	SAIDI (Minutes per customer)	SAIFI (Number per customer)
Urban	80	1.2	350	4

2.3 Key assumptions underpinning the identified need

The need to undertake reliability corrective action is predicated on the deteriorating condition of substation equipment at the existing Peakhurst STS, and the characteristics of any resultant outages. Key assumptions underpinning the identified need are presented in this section.

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[3] Granted by the Minster for Industry, Resources and Energy under the *Electricity Supply Act 1995 (NSW)*.

[4] SAIFI is calculated as the total number of interruptions that have occurred during the relevant period, divided by the number of customers. Momentary interruptions (which in NSW are currently defined as interruptions less than one minute) are typically not included.

[5] SAIDI is calculated as the sum of the duration of all customer interruptions over the period divided by the number of customers. Momentary interruptions (i.e. those of less than one minute) are typically not included.

[6] The Hon. Anthony Roberts MP Minister for Industry, Resources & Energy, Reliability and Performance Licence Conditions for Electricity Distributors, 1 December 2016, pp. 18-19 - available at: https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-administrative-electricity-network-operations-proposed-new-licence-conditions/ausgrid-ministerial-licence-conditions-1-december-2016.pdf

2.3.1 Deteriorating assets at the Peakhurst STS are expected to increase safety incidents and the risk of involuntary load shedding going forward

The Peakhurst STS was installed in 1964 and many critical assets of which it is comprised are reaching or have exceeded their service lives.

The table below presents the remaining lives of critical components of Peakhurst STS compared to standard age, which shows many of the 33kV isolators and earth switches, 33kV circuit breakers, 33kV circuit breaker ceilings and some of the power transformers have exceeded their standard lives.

Table 2.2 – Age of substation assets at Peakhurst STS

Type of Equipment	Manufacturer	Age (Years as on 2018)	Standard Age (Years)
33kV Circuit Breakers	Westinghouse	54	45
33kV Isolator & Earth Switch	Esantee	54	45
33kV Wall Bushing	-	54	45
Building – Switchroom & Control room (includes Stramit straw roof)	-	54	60
Fire System – 33kV Circuit Breaker Ceilings		54	45
Power Transformers 132/33kV	Toshiba / Wilson	54 /17	50
Auxiliary Transformers 11kV/415V	Johnson & Philips	54	50
132kV Isolator & Earth Switch	Dickson Primer / AEM	54 / 10	45
	Endurance Electric	54	45
132kV Voltage Transformers	Crompton Greaves/Ritz/Arteche	7-20	45
132kV Circuit Breakers	Mitsubishi/Siemens/ABB/Areva	7-10	45

The Peakhurst STS serves an enduring need for distributing electricity in the St George network area since it is the sole STS in the area. The substation is expected to serve between 90MVA to 140 MVA of load between 2018/19 and 2037/38, as shown in Figure 2-3.

Figure 2-3 – Peakhurst STS load forecast

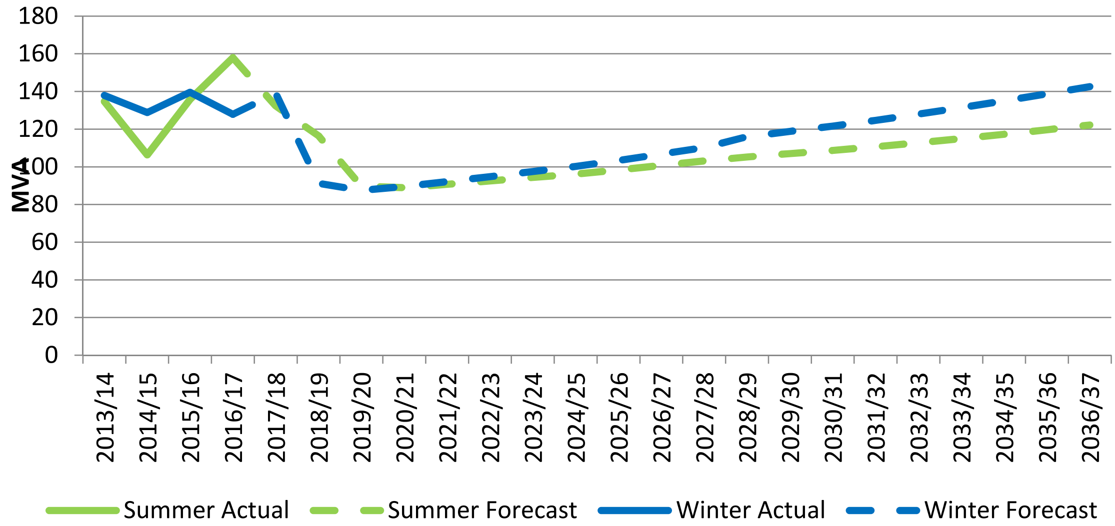

Figure 2-3 shows the reduced load from 2018/19 onwards on account of related projects retiring the Arncliffe and Rockdale substations (and transferring load elsewhere).

2.3.2 The probability of assets failing is material

Network asset failure probabilities and asset unavailability have a significant effect on any safety-related incidents and the expected level of involuntary load shedding. Ausgrid has adopted a constant failure rates and repair time due to limited availability of failure data for 33kV switchgear. The time to failure for the 33kV switchgear is determined as the point when insulation test results have exceeded the limit defined by industry best practices.

A detailed discussion of the probability of failure and asset availability is provided in Appendix D.

2.3.3 Feeder redundancy exists but capacity to undertake load transfers are limited

Load transfer capacity at peak is approximately 34MVA in the Peakhurst STS network area.

The level of cost expected from any involuntary load shedding is dependent on underlying assumptions relating to the level of redundancy in feeders and the capacity to transfer load to other substations that could supply load currently served by Peakhurst STS.

Both the degree of redundancy and the ability to transfer load elsewhere have been taken into account by Ausgrid in forecasting expected unserved energy.

3 Two credible options have been assessed

This section provides descriptions of the two credible options Ausgrid has identified as part of its network planning activities to date.

In particular, Ausgrid has identified two network options:

- Option 1: Brownfield development - refurbish the 33kV switchgear building and roof in situ, with like for like replacement of each 33kV circuit breaker and associated control and protection; or
- Option 2; Greenfield development – construct a new 33kV switchgear building equipped with new 33kV fixed pattern switchgear and associated control and protection, then retire existing 33kV switchgear building and associated 33kV bulk oil circuit breakers and associated control and protection.

The two credible options are summarised in the table below. All costs in this section are in 2018/19 dollars, unless otherwise stated.

Table 3.1 – Summary of the credible options considered

Network option	Key components	Estimated capital cost
Option 1 – Brownfield development	• resolution of the 33kV building issues at Peakhurst STS. • repair of the 33kV switchroom roofs and replacement of the roof sheeting in the 33kV circuit breaker bays and over the 33kV busbar gallery. • "like-for-like" replacement of 33kV bulk oil circuit breakers, 33kV Essantee isolators and 33kV feeder control and protection equipment.	$22.1 million + $0.5 million (decommissioning)
Option 2 – Greenfield development	• construction of a new 33kV switchroom. • installation of new 33kV switchgear. • retirement of the existing 33kV bulk oil circuit breakers and associated control and protection. • demolition of existing 33kV switchgear buildings.	$20.1 million + $2.0 million (decommissioning)

One further option was considered in addition to those set out in the table above, which involves retirement of the 33kV portion of Peakhurst STS, but was found to be non-credible. This option is discussed in section 3.3 below.

3.1 Option 1 – Brownfield development

This option involves the brownfield refurbishment of the 33kV building at Peakhurst STS, with the repair of the 33kV switchroom roofs and replacement of the roof sheeting in the 33kV circuit breaker bays and over the 33kV busbar gallery.

The work will require significant outages of the 33kV switchgear, as entire busbar groups would need to be taken out of service for safety reasons to undertake roof repairs. The "like-for-like" replacement of 33kV bulk oil circuit breakers, 33kV isolators and 33kV feeder control and protection equipment would be undertaken in stages, with roof/ceiling refurbishment works occurring first and then isolators & earth switches and circuit breakers replacement works later, to avoid work being carried out on top of others and prevent the introduction of dust from construction activities.

Ausgrid considers that the brownfield development option would have the benefit that the resulting arrangement can be easily expanded in the future should additional 33kV feeder circuit breakers be required. However, the brownfield development option also has additional associated risks compared to the greenfield development option considered, including:

- long delivery time frame due to staged refurbishment work;
- high complexity in fitting new circuit breakers in building while maintaining electrical clearances;
- high complexity in fitting new circuit breakers into existing wall-mounted, manually operated system;

- higher uncertainty in refurbishment costs;
- busbar section outages required to enable safe works to replace roofs and ceilings of each busbar chamber; and
- operational expenditure (OPEX) will increase over time if existing switchroom building is retained.

The estimated cost of this option is approximately $22.1 million with a further $0.5 million for decommissioning costs. Ausgrid assumes the brownfield replacement would commence in 2018/19 with the replacement scheduled to finish in 2023/24. Once the replacement is complete, operating costs are expected to be approximately $220,000 per annum (around 1.0 per cent of capital expenditure).

3.2 Option 2 – Greenfield development

This option addresses the asset issues at Peakhurst STS by the construction of a new 33kV switchroom, installation of new 33kV switchgear and the retirement of the existing 33kV switchgear and associated buildings. Specifically, the scope of the greenfield replacement involves:

- construction of a new building to be located on the existing substation site, to accommodate up to four sections of new 33kV indoor switchgear;
- installation and commissioning of three sections of new 33kV switchgear, allowing a fourth section to be installed and commissioned later ;
- installation of new local control and protection for the new 33kV switchgear, including compatibility upgrades at remote end substations where required;
- installation of local 132kV control and protection;
- installation of a new distributed SCADA system;
- installation of underground XLPE cable connections to transfer the following to the new 33kV switchgear:
    - feeders 765, 785 and 786 to supply Mortdale zone substation;
    - feeders 670, 778 and 779 to supply Riverwood zone substation;
    - feeders 706, 769 and 770 to supply Blakehurst and Sans Souci zone substations;
    - No. 1 and No.2 Capacitor banks at Peakhurst STS; and
    - Three 132/33kV power transformer connections.
- decommissioning and removal of the existing 33kV switchgear at Peakhurst STS:
    - all 33kV bulk oil circuits will be drained of oil;
    - all equipment removed and scrapped once spare parts have been salvaged where possible; and
    - demolition of the switchgear buildings to slab level.

Ausgrid has identified that the greenfield replacement would have the following benefits over and above Option 1:

- reduced safety and network risks – as new buildings and equipment allows the introduction of more reliable and safer systems;
- less uncertainty in capital expenditure (CAPEX) – from avoiding the need to address legacy equipment and systems that can be complicated and time consuming; and
- reduced OPEX over time – as maintenance on a new building is expected to be less than on an older building.

The estimated cost of this option is approximately $20.1 million with further $2.0 million for decommissioning costs. Ausgrid assumes the greenfield replacement would commence in 2018/19 with the replacement scheduled to finish in 2021/22. Once the replacement is complete, operating costs are expected to be approximately $100,000 per annum (around 0.5 per cent of capital expenditure).

3.3 Options considered but not progressed

Ausgrid has considered one other option that has not been progressed. This option was the retirement of the 33kV portion of the Peakhurst STS.

This would have involved the construction of two to four new 132/11kv zone substations and their associated 132kV feeders, along with transfer of all load and retirement of the existing 33/11kV zone substations. However, this option was not progressed due to its substantial cost, relative to the credible options outlined above (without providing commensurate market benefits). This is highlighted by the fact that the estimated costs of this option would range $50-$100 million, which is approximately two to four times greater than Options 1 & 2.

Ausgrid has also considered the ability of any non-network solutions to assist in meeting the identified need. A demand management assessment into reducing the risk of unserved energy from the 33kV feeders showed that non-network alternatives cannot cost-effectively address the risk, compared to the two network options outlined above. This result is presented and explained in further detail in the separate notice released in accordance with clause 5.17.4(d) of the NER.

If during the course of this RIT-D process, a cost-effective non-network solution emerges, then it will be assessed alongside the other options.

4 How the options have been assessed

This section outlines the methodology that Ausgrid has applied in assessing market benefits and costs associated with each of the credible options considered in this RIT-D.

4.1 General overview of the assessment framework

All costs and benefits for each credible option have been measured against a ‘business as usual’ base case. Under this base case, Ausgrid is assumed to undertake escalating regular and reactive maintenance activates as the probability of failure and outages increases over time in the absence of an asset replacement program.

The RIT-D analysis has been undertaken over a 20-year period, from 2018/19 to 2037/38. Ausgrid considers that a 20-year period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. While the capital components of the credible options have asset lives greater than 20 years, Ausgrid has taken a terminal value approach to incorporating capital costs in the assessment, which ensures that the capital cost of long-lived options is appropriately captured in the 20-year assessment period.

Given that no non-network options have been found to be viable, the appropriate discount rate is considered to be the regulated cost of capital. As a result, Ausgrid has adopted a real, pre-tax discount rate of 4.19 per cent, equal to the latest AER Final decision for a DSNP’s regulatory proposal at the time of preparing this DPAR[7].

4.2 Ausgrid’s approach to estimating project costs

Ausgrid has estimated capital costs by considering the scope of works necessary under each credible option together with costing experience from previous projects of a similar nature. Where possible, Ausgrid has also estimated capital costs for each credible option using supplier quotes or other pricing information.

Operating and maintenance costs have been determined for each option by comparing the operating and maintenance costs with the option in place to the operating and maintenance costs without the option in place. These costs are included for each year in the planning period. If operating and maintenance costs are reduced with an option in place, the cost savings are effectively treated as a benefit in the assessment.

Operating costs have been estimated for each credible option and the base case by taking into account:

- the probability and expected level of network asset faults, which translates to the level of corrective maintenance costs; and
- the level of regular maintenance required to maintain network assets in good working order, including planned refurbishment costs.

All options reduce the incidence of asset failures relative to the base case, and hence the expected operating and maintenance costs associated with restoring supply.

Ausgrid has also included the financial costs associated with safety outcomes that are assumed to be avoided under each of the options, relative to the base case.

4.3 Market benefits are expected from reduced operational risks and involuntary load shedding

Ausgrid considers that the only relevant category of market benefits prescribed under the NER for this RIT-D relates to changes in involuntary load shedding. The assumptions made to estimate involuntary load shedding are outlined in this section. Appendix C outlines the categories of market benefit that Ausgrid considers are not material for this RIT-D.

While not a ‘market benefit’ under the RIT-D, Ausgrid considers that a key source of ‘benefit’ for this RIT-D comes in the form of avoided safety-related operating costs. If the identified assets are left to further deteriorate, there is an increasing likelihood that there will be an explosive failure of switchgears at Peakhurst and/or a fire at the STS, both of which may results in fatalities or severe injuries to Ausgrid staff onsite or to the general public nearby. We therefore also present a summary of the key assumptions relating to these reduced safety-related costs below.

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[7] See TasNetworks’ PTRM for the 2017-19 period, available at: https://www.aer.gov.au/networks-pipelines/determinations-access-arrangements/tasnetworks-determination-2017-2019/final-decision

4.3.1 Avoided safety-related operating costs

Avoided safety related operating costs relate to expected risk costs arising from adverse events that affect health and safety of Ausgrid employees and the public. Safety risk costs have been estimated on three main factors:

- the consequence of a severe safety event;
- the probability of exposure of people to a severe adverse event at Peakhurst STS; and
- the probability of equipment failure.

Ausgrid estimates the consequence of a severe safety event to have a cashflow impact of several hundred million dollars[8]. This is because not only significant financial compensation would be required by the occurrence of fatalities and/or significant permanent injuries to one or more persons, but also there will be significant costs in terms of extensive litigation and adverse national media attention.

To calculate the assumed level of safety risk costs, the consequence of a severe safety event and probability of exposure to a severe adverse event are multiple together with the probability of occurrence of equipment failure. Appendix D provides additional detail on the assumptions underpinning these avoided costs.

Ausgrid recognises that there is a level of uncertainty in these estimates and therefore sensitivities have been considered, using values of ± 30% of the base case.

4.3.2 Avoided unserved energy (reduced involuntary load shedding)

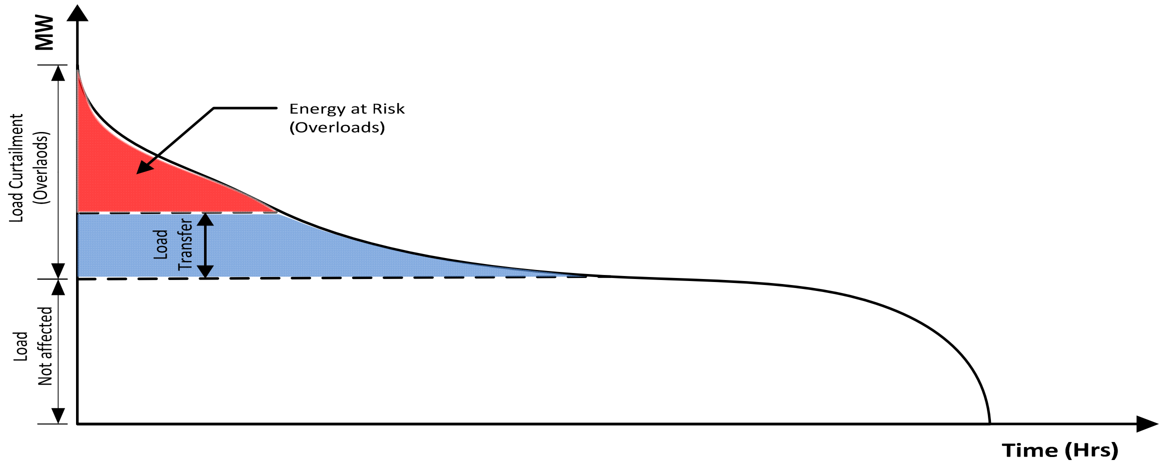
Unserved energy (USE) is the amount of energy that customers request to utilise but cannot be supplied due to a network capacity limitation. The customer's load is interrupted from the network without their agreement or prior warning. Ausgrid has forecast load over the assessment period and has quantified the expected unserved energy by comparing forecast load to network capabilities under system normal and network outage conditions. A reduction in involuntary load shedding expected from an option, relative to the base case, results in a positive contribution to market benefits of the credible option being assessed.

The Expected Unserved Energy (EUE) is the probability weighted average amount of load that would need to be involuntarily curtailed due to system limitations (i.e. the network being overloaded). These limitations arise from the unavailability of network elements and the resulting reduction in network capacity to supply the load. It also relates to the availability of network connectivity and design configuration at the substation.

The load duration curve at a substation is used to determine the energy at risk and/or the amount of load curtailment required at certain loading levels. The amount of load curtailment can be determined by using a discrete number of load points and the capacity adequacy at the substation following various credible contingencies and/or outages (i.e. single or multiple transformers out of service).

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 is illustrated in the diagram below.

Figure 4-1 – Illustration of Load Curtailment



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[8] Based on Ausgrid Risk Management Strategy, approved by Ausgrid's Board in 2015.

The calculation of the energy at risk considers the zone substation load forecast which includes the quantity of new additional load requested in the customer connection application. The expected unserved energy is the energy at risk weighted by the probability of each state and/or state probabilities of all credible contingencies or outages.

The market benefit as a result of the preferred option by eliminating unserved energy with a network solution is estimated by multiplying the unserved energy by the Value of Customer Reliability (VCR). The VCR is measured in dollars per kWh and is used as a proxy to evaluate the economic impact of unserved energy on customers under the RIT-D.

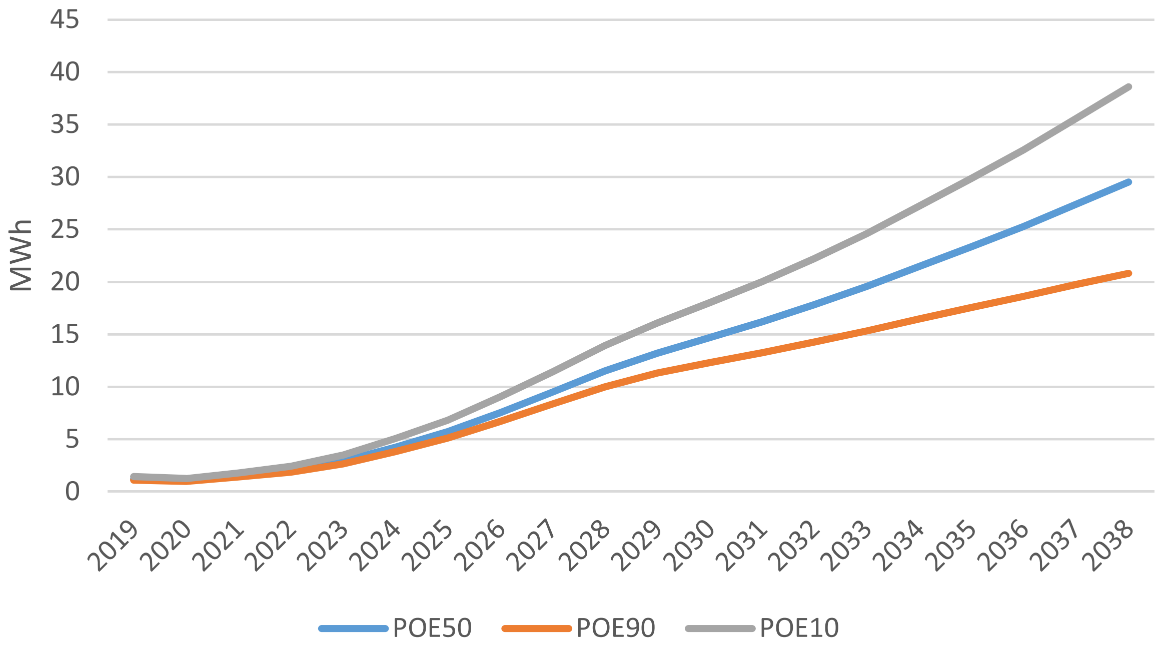
Ausgrid has applied a central VCR estimate of $41/kWh, which has been derived from the 2014 AEMO VCR estimates[9] using CPI to escalate the AEMO estimate to current real values.

We have also investigated the effect of assuming both a lower and higher underlying VCR estimate. The AEMO Value of Customer Reliability – Application Guide recommends using values of ± 30% of the base case VCR for the purposes of testing how sensitive investment decisions are to the VCR input. Thus, a lower VCR of $29/kWh and a higher VCR of $53/kWh have been chosen as reasonable for the low and high benefit scenarios.

In addition, while load forecasts are not a determinant of the identified need (since the reliability standards expected to be breached relate to the *duration* and *frequency* of supply interruptions – neither of which are affected by underlying load), Ausgrid has investigated how assuming different load forecasts going forward changes the expected net market benefits under the options. In particular, we have investigated three future load forecasts for the area in question – namely a central forecast using our 50 per cent probability of exceedance ('POE50') forecasts, as well as a low forecast using the POE90 forecasts and a high forecast using the POE10 forecasts.

The figure below shows the assumed levels of unserved energy, under each of the three underlying demand forecasts investigated over the next ten years. For clarity, this figure illustrates the MWh of unserved energy assumed under each load forecast, if none of the credible options are commissioned.

Figure 4-2 – Assumed level of USE under each of the three demand forecasts



The level of USE only increases to significant levels after 2029/30, as shown in Figure 4-2. This exponential increase does not affect the ranking of credible options at all since the avoided safety-related operating costs (i.e. managing the safety and fire risk at the site) is by far the main benefit and occurs earlier than the USE in the assessment period. It should also be noted that the two credible network options avoid a similar level of USE.

[9] AEMO, *Value of Customer Reliability Review*, September 2014, Final Report.

4.4 Three different 'scenarios' have been modelled to address uncertainity

RIT-D assessments are required to be based on cost-benefit analysis that includes an assessment of 'reasonable scenarios', which are designed to test alternate sets of key assumptions and whether they affect identification of the preferred option.

Ausgrid has elected to assess three alternative future scenarios – namely:

- Low benefit scenario – Ausgrid has adopted a number of assumptions that give rise to a lower bound NPV estimate for each credible option, in order to represent a conservative future state of the world with respect to potential market benefits that could be realised under each credible option;
- Baseline scenario – the baseline scenario consists of assumptions that reflect Ausgrid's central set of variable estimates, which, in Ausgrid's opinion, provides the most likely scenario; and
- High benefit scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected potential market benefits.

Given that no non-network options have been found to be viable, Ausgrid considers the appropriate discount rate is the regulated cost of capital, which is equivalent to 4.19 per cent at the time of preparing this DPAR and is used across all scenarios investigated.

Table 4.1 – Summary of the three scenarios investigated

Variable	Scenario 1 – low benefits	Scenario 2 – baseline	Scenario 3 – high benefits
Capital cost	110 per cent of capital cost estimate for greenfield and 130 per cent for brownfield	100 per cent of capital cost estimate	90 per cent of capital cost estimate
Demand	POE90	POE50	POE10
VCR	$29/kWh (30 per cent lower than the central, AEMO-derived estimate)	$41/kWh (Derived from the AEMO VCR estimates)	$53/kWh (30 per cent higher than the central, AEMO-derived estimate)
Safety risk cost	70 per cent of baseline estimate	100 per cent of baseline estimate	130 per cent of baseline estimate
Unplanned corrective maintenance cost	70 per cent of baseline corrective maintenance cost estimates	100 per cent of baseline corrective maintenance cost estimates	130 per cent of baseline corrective maintenance cost estimates

Ausgrid considers that the baseline scenario is the most likely, since it is based primarily on a set of expected/central assumptions. Ausgrid has therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each. However, Ausgrid notes that the identification of the preferred option is the same across all three scenarios, i.e. the result is insensitive to the assumed scenario weights.

5 Assessment of credible options

This section summarises the results of the NPV analysis, including the sensitivity analysis undertaken. All credible options assessed as part of this RIT-D have been compared against a 'business as usual' base case.

5.1 Gross benefits estimated for each credible option

Table 5.1 below summarises the gross benefit of each credible option relative to the base case in present value terms. The gross market benefit for each option has been calculated for each of the three reasonable scenarios outlined in the section above.

Table 5.1 – Present value of benefits of each credible option relative to the base case, $m 2018/19

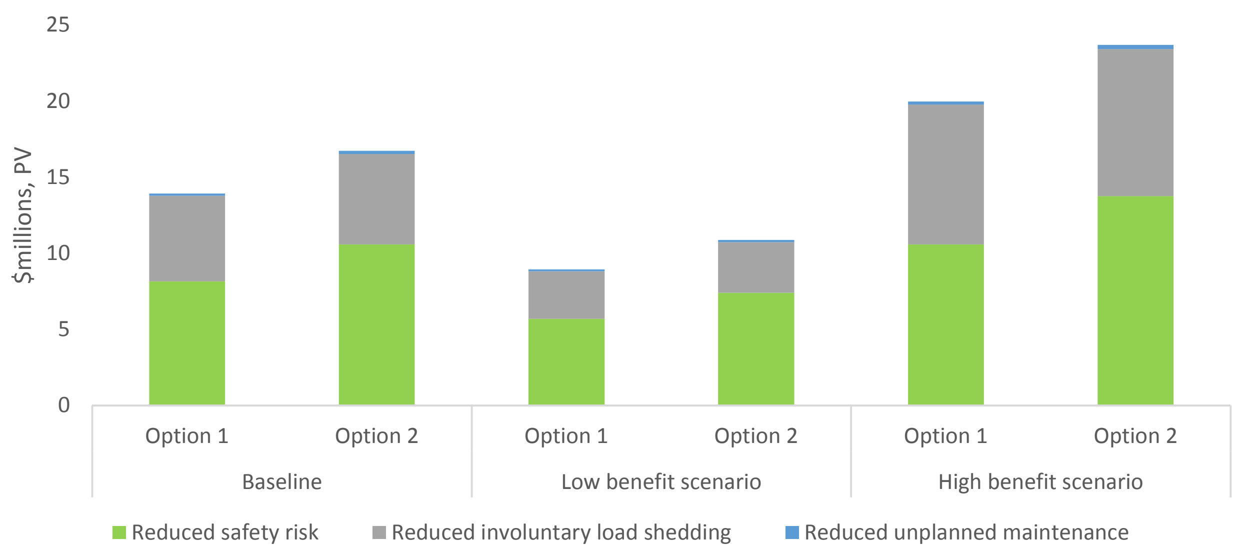
Option	Scenario 1 - Baseline	Scenario 2 – Low benefit	Scenario 3 – High benefit	Weighted PV of gross benefits
Scenario weighting	50%	25%	25%	
Option 1	13.9	8.9	20.0	14.2
Option 2	16.7	10.9	23.7	17.0

The figure below provides a breakdown of all benefits relating to each credible option. For clarity, we have combined in this chart 'market benefit' (i.e. reduced involuntary load shedding) with avoided cost benefits (i.e. reduced safety costs and avoided corrective/unplanned maintenance).

The two options are found to have similar overall benefit. This is driven by the fact that all options are assumed to be commisioned only two years appart and so avoid similar levels of expected unserved energy and safety costs.

On a weighted present value basis, Option 2 is expected to provided approximately $2.8 million more gross benefits arising from two additional years of benefits in 2021/22 and 2022/23 compared to Option 1.

Figure 5-1 – Breakdown of gross economic benefits of each credible option relative to the base case



5.2 Estimated costs for each credible option

The table below summarises the costs of each credible option relative to the base case in present value terms. The cost is the sum of the project capital costs, routine maintenance and decommissioning costs associated with each option. The cost of each option has been calculated for each of the three reasonable scenarios, in accordance with the approaches set out in Section 4.4.

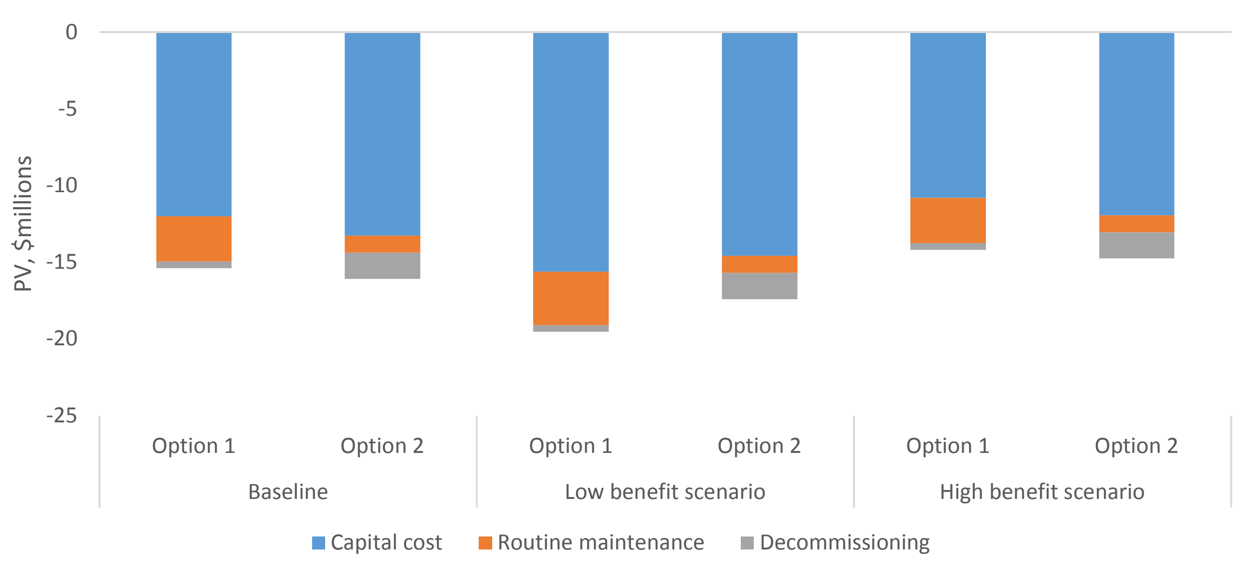
Table 5.2 – Present value of costs of each credible option relative to the base case, $m 2018/19

Option	Scenario 1 - Baseline	Scenario 2 – Low benefit	Scenario 3 – High benefit	Weighted costs
Scenario weighting	50%	25%	25%	
Option 1	-15.4	-19.5	-14.2	-16.1
Option 2	-16.1	-17.4	-14.8	-16.1

The figure below provides a breakdown of costs relating to each credible option. Capital costs are the determining factor for the ranking of credible options considered.

The two options have similar costs under all scenarios in present value terms, noting that Option 1 has higher routine maintenance costs associated with keeping the existing building in service, and that Option 2 involves higher decommissioning costs arising from demolition costs associated with the Peakhurst substation zone buildings, while Option 1 would continue to make use of them.

Figure 5-2 – Present value of costs of each credible option relative to the base case



5.3 Net present value assessment outcomes

Table 5.3 summaries the results in NPV terms for each credible option under each scenario. The net result is the gross market benefit (as set out in Table 5.1) minus the cost of each option (as outlined in Table 5.2) in present value terms.

Overall, Option 2 exhibits the highest estimated net market benefit, which is driven primarily by it having two more years of market and avoided cost benefits out of the two credible options considered.

Table 5.3 – Net Present Value of credible options relative to the base case, $m 2018/19[10]

Option	Capital costs	Operating costs	Weighted PV of gross benefits	Weighted PV of net benefits	Option ranking
Option 1	-12.6	-3.5	14.2	-1.9	2
Option 2	-13.3	-2.8	17.0	0.9	1

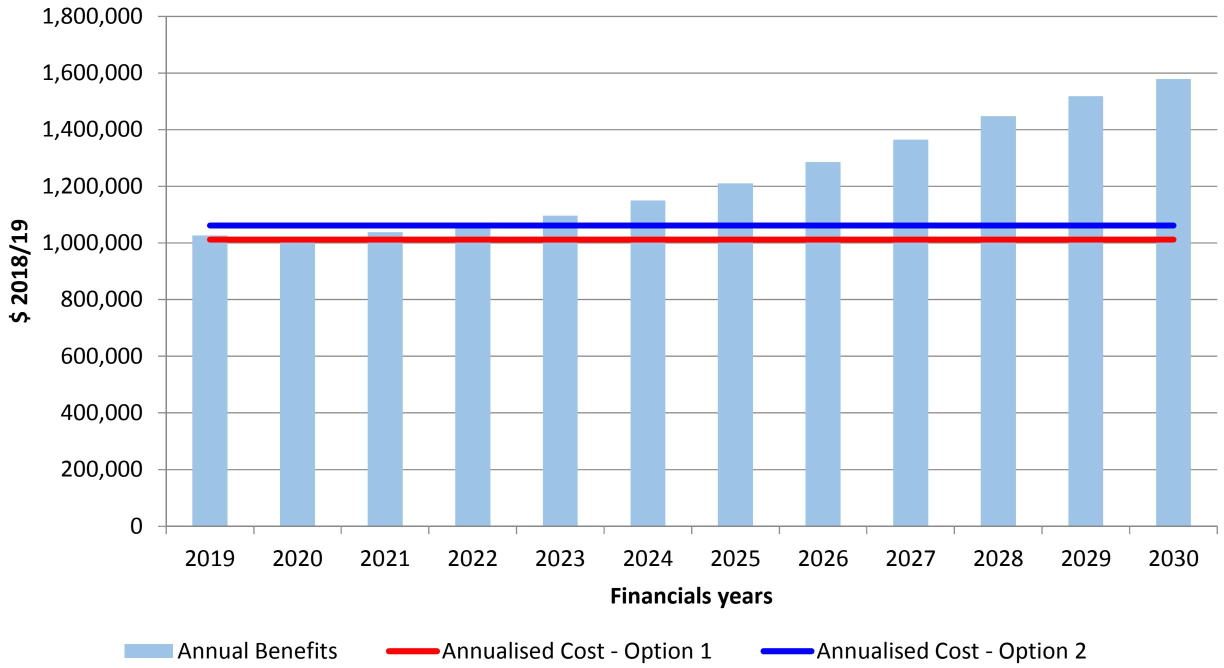
[10] Figures in Table 5.3 may not add due to rounding.

5.4 Project Timing

As a result of the project having no viable non-network solutions and being driven primarily by safety considerations, Ausgrid has estimated the project timing based on the year in which year the annualised cost of the project falls below the expected benefits from commissioning the project that year. The cost benefit analysis has been undertaken using the regulated cost of capital, which is equivalent to 4.19 per cent at the time of preparing this DPAR.

The figure below illustrates the project timing estimated for both credible options.

Figure 5-3 – Project timing of credible options



It should be noted that Option 1 cannot be delivered earlier than 2023/24 due to the need to undertake staged construction next to energised equipment. For Option 2 the annual benefits of avoided safety risks exceed the annualised cost of the project from 2021/22.

5.5 A range of sensitivity tests have also been undertaken on key assumptions

Ausgrid has undertaken a through sensitivity testing exercise to understand the robustness of the RIT-D assessment to underlying assumptions about key variables.

Once the timing of the project has been determined, the following sensitivities have been investigated:

- a 10 per cent increase for the greenfield development (30 per cent in the case of the brownfield development) and 10 per cent decrease in the assumed network capital costs;
- alternate forecasts of maximum demand growth, based on POE10 (high) and POE90 (low);
- a lower VCR ($28/kWh) and higher VCR value ($90/kWh);
- 30 per cent lower and 30 per cent higher avoided safety risk costs;
- 30 per cent lower and 30 per cent higher avoided unplanned corrective maintenance; and
- a lower discount rate of 4.19 per cent as well as a higher rate of 8.07 per cent.

Table 5.4 presents the results of these sensitivity tests and, for each sensitivity, labels the highest ranked option using bold text. The analysis strongly indicates that Option 2 is the preferred credible option on an NPV basis under all sensitivities.

Table 5.4 - Sensitivity testing results

Sensitivity	Option 1	Option 2
Higher capital cost	-5.6	**-0.7**
10% Lower capital cost	-0.3	**2.0**
Unserved energy under POE10	0.0	**2.1**
Unserved energy under POE 90	-2.6	**-0.6**
30% higher safety risk	1.0	**3.8**
30% lower safety risk	-3.9	**-2.5**
30% higher avoided unplanned corrective maintenance	-1.4	**0.7**
30% lower avoided unplanned corrective maintenance	-1.5	**0.6**
VCR $53/kWh	-0.2	**2.4**
VCR $28/kWh	-3.2	**-1.1**

6 Proposed preferred option at this draft stage

Option 2 has found to be the preferred option, which satisfies the RIT-D. It involves the construction of a new 33kV switchroom, installation of new 33kV switchgear and the retirement of the existing 33kV switchgear buildings at Peakhurst STS.

Specifically, the scope of the greenfield development involves:

- construction of a new building to be located on the existing substation site, to accommodate up to four sections of new 33kV indoor switchgear;
- installation and commissioning of three sections of new 33kV switchgear, allowing a fourth section to be installed and commissioned later;
- installation of new control and protection for the new 33kV switchgear, including compatibility upgrades at remote end substations where required;
- installation of local 132kV control and protection;
- installation of a new distributed SCADA system;
- installation of underground XLPE cable connections to transfer the 33kV feeders, capacitor banks and 132/33kV power transformer connections to the new 33kV switchgear; and
- decommissioning and removal of the existing 33kV switchgear and demolition of the switchgear buildings to slab level.

The estimated cost of this option is approximately $20.1 million with further $2.0 million for decommissioning costs. Ausgrid assumes the greenfield development would commence in 2018/19 with the replacement scheduled to be commissioned in 2021/22 and subsequent decommissioning of the aged network assets in 2022/23. Once the replacement is complete, operating costs are expected to be approximately $100,000 per annum (around 0.5 per cent of capital expenditure).

Ausgrid is the proponent for Option 2.

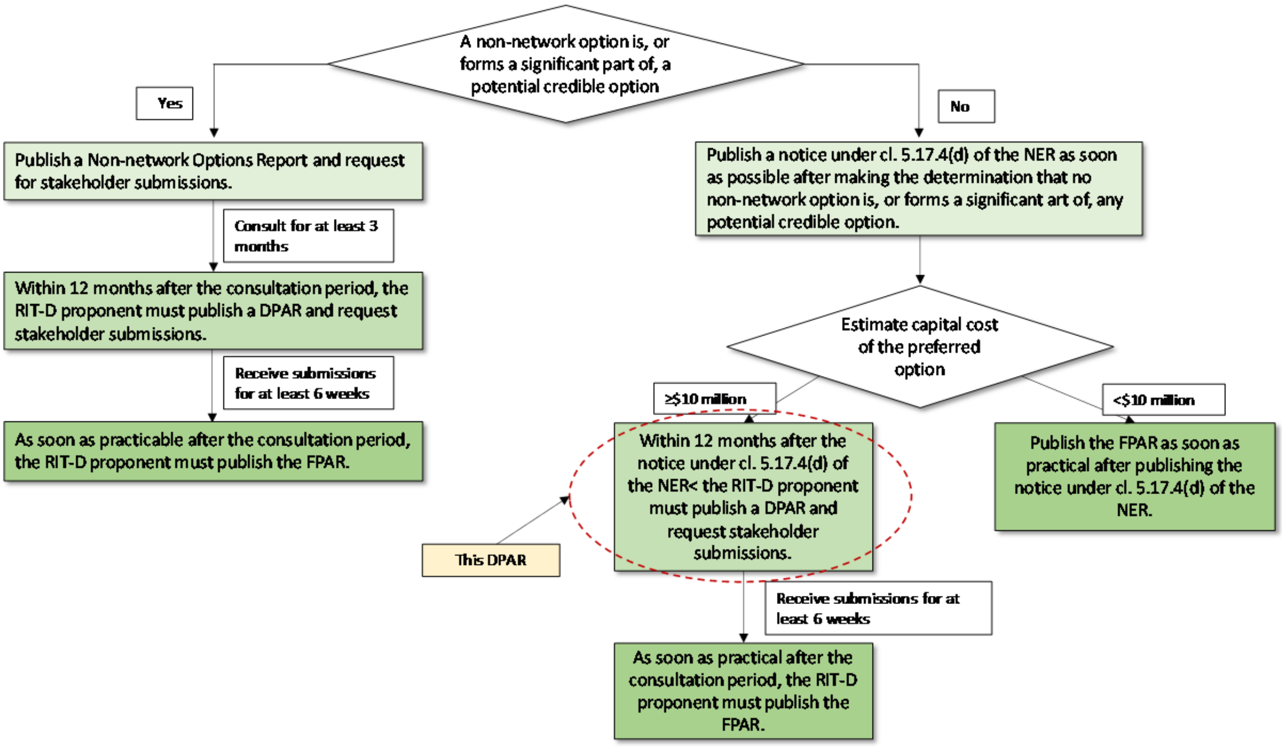
Appenidx A – Checklist of compliance clauses

This section sets out a compliance checklist that demonstrates the compliance of this DPAR with the requirements of clause 5.17.4(j) of the National Electricity Rules version 111.

Rules clause	Summary of requirements	Relevant sections in the DPAR
5.17.4(j)	(1) a description of the identified need for the investment	2
	(2) the assumptions used in identifying the identified need	2.3
	(3) if applicable, a summary of, and commentary on, the submissions on the non-network options report	NA
	(4) a description of each credible option assessed	3
	(5) where a DNSP has quantified market benefits, a quantification of each applicable market benefit for each credible option;	5.1
	(6) a quantification of each applicable cost for each credible option, including a breakdown of operating and capital expenditure	5.2
	(7) a detailed description of the methodologies used in quantifying each class of cost and market benefit	4.3
	(8) where relevant, the reasons why the RIT-D proponent has determined that a class or classes of market benefits or costs do not apply to a credible option	Appendix C
	(9) The results of a net present value analysis of each of credible option and accompanying explanatory statements regarding the results	5
	(10) the identification of the proposed preferred option	6
	(11) for the proposed preferred option, the RIT-D proponent must provide: (i) details of technical characteristics; (ii) the estimated construction timetable and commissioning date (where relevant); (iii) the indicative capital and operating cost (where relevant); (iv) a statement and accompanying detailed analysis that the proposed preferred option satisfies the regulatory investment test for distribution; and (v) if the proposed preferred option is for reliability corrective action and that option has a proponent, the name of the proponent	6
	(12) Contact details for a suitably qualified staff member of the RIT-D proponent to whom queries on the draft report may be directed.	1.2

Appendix B – Process for implementing the RIT-D

For the purposes of applying the RIT-D, the NER establishes a three stage process: (1) the Non-Network Options Report (or notice circumventing this step); (2) the DPAR; and (3) the FPAR. This process is summarised in the figure below.



Appendix C – Market benefit classes considered not relevent

The market benefits that Ausgrid considers will not materially affect the outcome of this RIT-D assessment include:

- changes in voluntary load curtailment;
- costs to other parties;
- load transfer capability and embedded generators;
- option value; and
- electrical energy losses.

The reasons why Ausgrid considers that each of these categories of market benefit is not expected to be material for this RIT-D are outlined in the table below.

Table 0.1 – Market benefit categories under the RIT-D not expected to be material

Market benefits	Reason for excluding from this RIT-D
Changes in voluntary load curtailment	Ausgrid notes that the level of voluntary load curtailment currently present in the NEM is limited. Where the implementation of a credible option affects pool price outcomes, and in particular results in pool prices reaching higher levels on some occasions than in the base case, this may have an impact on the extent of voluntary load curtailment. Ausgrid notes that none of the options are expected to affect the pool price and so there is not expected to be any changes in voluntary load curtailment.
Costs to other parties	This category of market benefit typically relates to impacts on generation investment from the options. Ausgrid notes that none of the options will affect the wholesale market and so we have not estimated this category of market benefit.
Changes in load transfer capacity and embedded generators	Load transfer capacity between substations is predominantly limited by the high voltage feeders that connect substations. Credible options under consideration do not affect high voltage feeders and therefore are unlikely to materially change load transfer capacity. Further, credible options are unlikely to enable embedded generators in Ausgrid's network to be able to take up load given the size and profile of the load serviced by network assets currently considered for replacement. Consequently, Ausgrid has not attempted to estimate any benefits from changes in load transfer capacity and embedded generators.
Option value	Option values arise where there is uncertainty regarding future outcomes, the information that is available in the future is likely to change, and the credible options considered have sufficiently flexible to respond to that change. Ausgrid notes that none of the credible options assessed involve stages or any other flexibility and so we do not consider that option value is relevant.
Changes in electrical energy losses	Ausgrid does not expect that any of the credible options considered would lead to significant changes in network losses and so have not estimated this category of market benefits.

Appendix D – Additional detail on the assessment methodology

To determine if a project is to be executed, the one year deferral benefit is compared with the difference in expected unserved energy (USE) plus the difference in additional risk costs (such as Safety, environmental, corrective maintenance) between the existing and the proposed configuration. For the investment to be considered favorable in a given year, the combined USE and risk costs associated with the existing configuration must, as a minimum, exceed the one year deferral benefit of the proposed project in that year.

For a given year the benefit in deferring the project is:

$$\text{Benefit} = sV - A_m \quad (1)$$

Where:

s = Discount rate

V = Capital Investment

A_m = Annual Maintenance Cost

For a given year the cost is the unserved energy plus the difference in additional risk costs

$$\text{Cost} = USE_{diff} + A_{risk,diff} \quad (2)$$

USE_{diff} = Difference in unserved energy between existing and proposed configurations

The difference in the USE is given by

$$USE_{diff} = USE_{existing} - USE_{proposed} \quad (3)$$

A_{risk} = Annual cost of the difference in additional risks such as environmental, safety etc

The cost benefit ratio (CBR) is given by:

$$\text{CB Ratio} = \frac{USE_{diff} + A_{risk,diff}}{sV - A_m} \quad (4)$$

If for a given year the CBR in (4) is equal to or greater than 1, then the investment is cost effective and should proceed in that year.

Input Information

The reliability information utilised for the assessment of USE at Peakhurst STS is:

Asset	Type	Failure Frequency (f/yr)	Repair Time (hrs)	Comments
33kV Switchgear	Westinghouse 345GC	0.033	40	All feeder and Tx breakers are of this type. Failure rate assumed approximately equal to MTBF. MTBF taken from Ausgrid failure data library spreadsheet.
33kV Busbars	N/A	0.02	40	Assumed 1/50yr failure rate as no data available. Failure rate includes isolator failures on the 33kV bus side of any circuit breaker

Table 1 – Failure Rates and Repair Times for Peakhurst STS

Constant failure rates and repair rates have been assumed over time.

It is understood that failure rates are likely to increase over time based on wear out characteristics of equipment and that non-increasing failure rates may underestimate these increases. Ausgrid will continue to refine equipment failure modeling and its application over successive replacement needs assessments in the future.

For the purposes of this analysis, Ausgrid has quantified the risk of physical harm as a ‘severe’ safety outcome from Ausgrid’s corporate risk matrix.

Three key factors are used to quantify the safety risk.

- Safety Consequence Value
- Factor (α) – being a measure of the probability that a given failure will lead to a ‘severe’ safety outcome. A key element of this is the ‘exposure rate’ which depends on the proportional of time a person may be in the vicinity of the asset at the time of a major failure occurs.

  $$Exposure\ Rate\ (\alpha) = \frac{Site\ visits\ per\ annum \times duration\ of\ site\ visit\ in\ hours}{365 \times 24} x\ \%\ of\ incidents\ resulting\ in\ severe\ consequences$$

  It is assumed that for a given failure where someone is exposed, there is a 1 in 10 (i.e. 10%) chance of it resulting in a severe outcome.

- Failure rate of 33kV SG section

Hence, safety impact is calculated as below.

$$Safety\ Impact\ Cost = Safety\ consequence \times \alpha \times Failure\ rate$$

Ausgrid has quantified the corrective maintenance that is required due to the failure of 33kV circuit breaker that may lead to repair of the blast wall and roller doors. The corrective maintenance impact is calculated as below:

$$Corrective\ Maintenance\ \ Cost = Repair\ cost\ x\ failure\ rate$$

Ausgrid