Ensuring Reliable Supply for Adelaide’s Eastern Suburbs

Final Project Assessment Report (FPAR)

22 December 2022

SA Power Networks
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Disclaimer

This Final Project Assessment Report (FPAR) has been prepared in accordance with and is limited to the requirements of Clause 5.17.4 of the National Electricity Rules for the purpose of publicly announcing the provisional outcome of SA Power Networks evaluation of options in response to a specific set of identified needs. The FPAR is a summary or general description only of the matters considered by SA Power Networks when evaluating the various options. It is not intended to be used for other purposes, such as making decisions to invest in generation, transmission or distribution capacity. This document has been prepared using information provided by, and reports prepared by, a number of third parties. It contains assumptions regarding, among other things, economic growth and load forecasts that, by their nature, may or may not prove to be correct. SA Power Networks recommends and advises that anyone proposing to use this information should verify its reliability, accuracy and completeness before committing to any course of action or expenditure. SA Power Networks accepts no responsibility or liability of any nature whatsoever for any loss or damage that may be incurred by any person acting in reliance on the information or assumptions contained in this document. Any use of or reliance upon the information or assumptions contained in this report is at the sole risk of the user. SA Power Networks makes no warranties or representations whatsoever as to the reliability, accuracy and completeness of any information contained in this document. SA Power Networks specifically disclaims any liability or responsibility for any errors or omissions in any of the information contained in this document.

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Contents

Figures

Tables

Changes (from the DPAR)

- Noted no submissions received during the DPAR consultation period.
- Transmission component of the Capex increased by $10M (to $15M for Option 1). No tangible impact to NPV analysis.

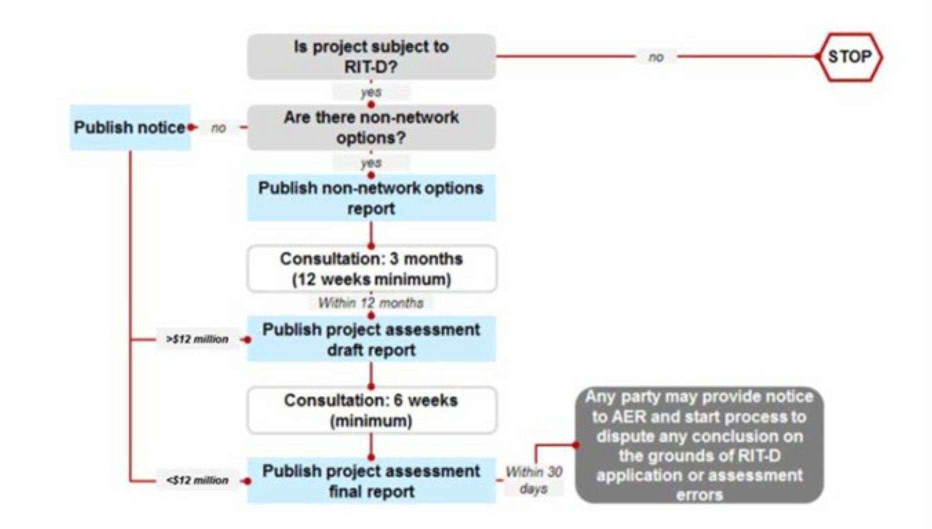
1 Introduction

The Northfield 66 kilovolt (kV) substation is a key link in the 66kV interconnected network that supplies approximately 115,000 customers in Adelaide's eastern suburbs. It was installed in the late 1980s and components of its infrastructure are now reaching the end of their service lives and are in poor condition. In particular, the gas insulated switchgear (GIS) that forms part of the substation is in poor mechanical condition and subject to accelerated ageing. These condition issues are principally a result of significant external corrosion – specifically on the flanges and O-rings in the GIS – caused by 35 years of continuous service in an outdoor environment.

Reflecting its age, the condition of the Northfield GIS has deteriorated to the extent that there is a material risk of asset failure. Failure of the GIS installation has the potential to lead to significant levels of unserved energy to customers in Adelaide's eastern suburbs. SA Power Networks has therefore commenced this Regulatory Investment Test for Distribution (RIT-D) to determine the most efficient means of ensuring reliable supply for Adelaide's eastern suburbs. Further, SA Power Networks expects there to be significant market benefits associated with ensuring reliable supply for Adelaide's eastern suburbs – principally in the form of avoided involuntary load shedding – and considers the identified need for this RIT-D to be delivering market benefits. In addition to market benefits, SA Power Networks expects there will be significant environmental benefits from avoided leakages of the gas used to insulate the Northfield GIS.

SA Power Networks has prepared this Final Project Assessment Report (FPAR) in accordance with the requirements of clause 5.17.4 of the National Electricity Rules (NER). It is the third and final stage of the formal consultation process set out in the NER in relation to applying the RIT-D – figure 1.1 below. This FPAR follows the publication by SA Power Networks of the options screening notice and the Draft Project Assessment Report (DPAR), including the associated consultation periods. SA Power Networks has concluded that there will not be a non-network option, or stand-alone power system (SAPS) option, that could form a potential credible option on a standalone basis, or that could form a significant part of a potential credible option for this RIT-D.

Figure 1.1: Overview of the RIT-D process



The purpose of this FPAR is to:

- describe the identified need SA Power Networks 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;

- explain why SA Power Networks has determined that classes of market benefits or costs do not apply to the credible options;
- present the results of a net present value analysis of each credible option, including an explanation of the results; and
- identify the proposed preferred option.

If you have any comments or enquiries regarding this notice, please send to the following email: requestforproposals@sapowernetworks.com.au.

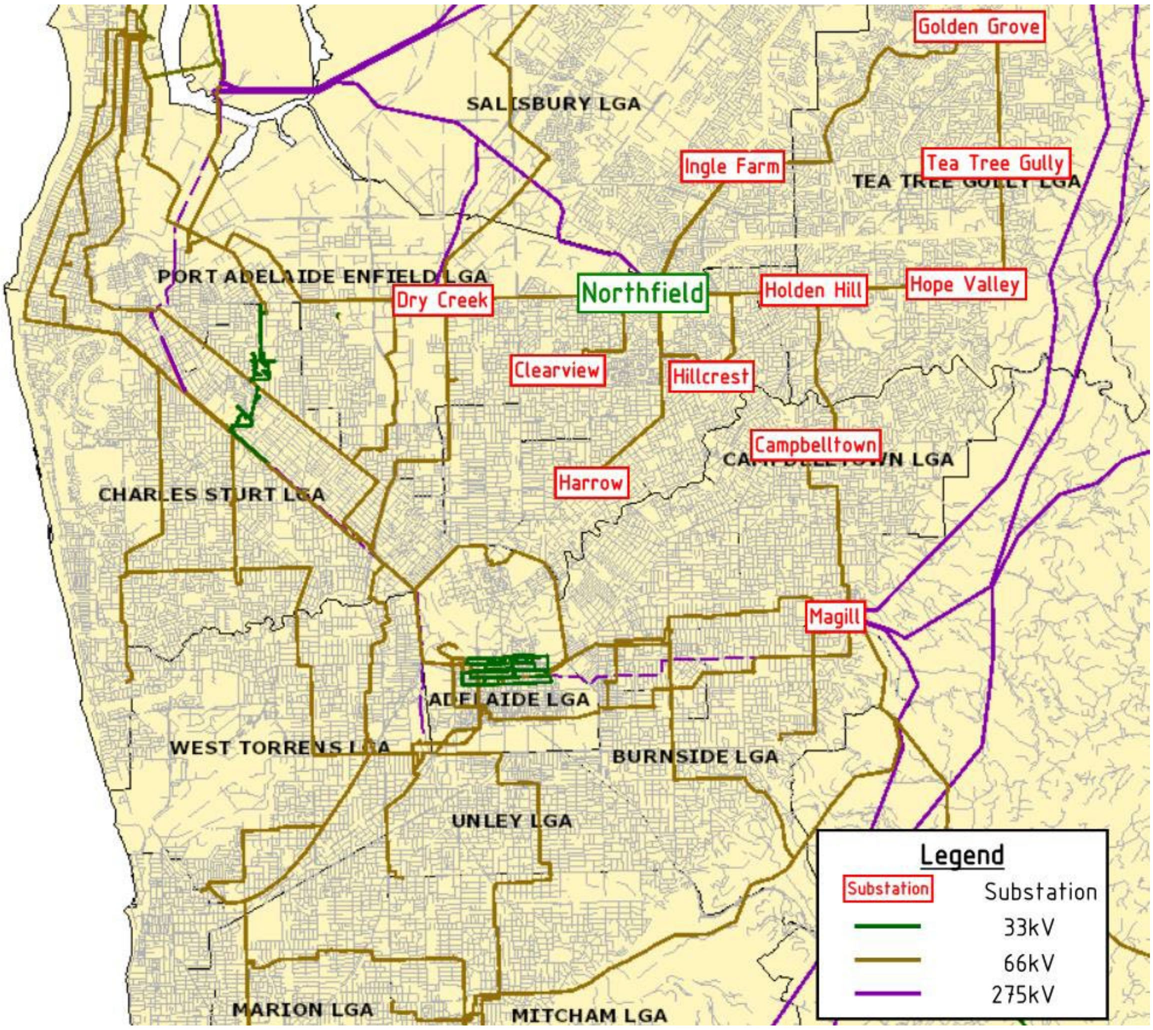
2 Description of the Identified Need

This section describes the identified need for this RIT-D and sets out the key assumptions and methodologies that underpin this need. SA Power Networks has used these assumptions in making the determination that there will not be a potential credible non-network option or SAPS option on a standalone basis, or that forms a significant part of a potential credible option, capable of meeting this need, in accordance with clause 5.17.4(c) of the NER.

2.1 Relevant area of the SA Power Networks distribution network

The Northfield substation is a key link in the 66kV interconnected network that supplies approximately 115,000 customers in Adelaide's eastern suburbs. Figure 2.1 provides an overview of where the Northfield substation is located within the SA Power Networks distribution network and the surrounding network infrastructure.

Figure 2.1: Northfield GIS location within Greater Adelaide Metropolitan

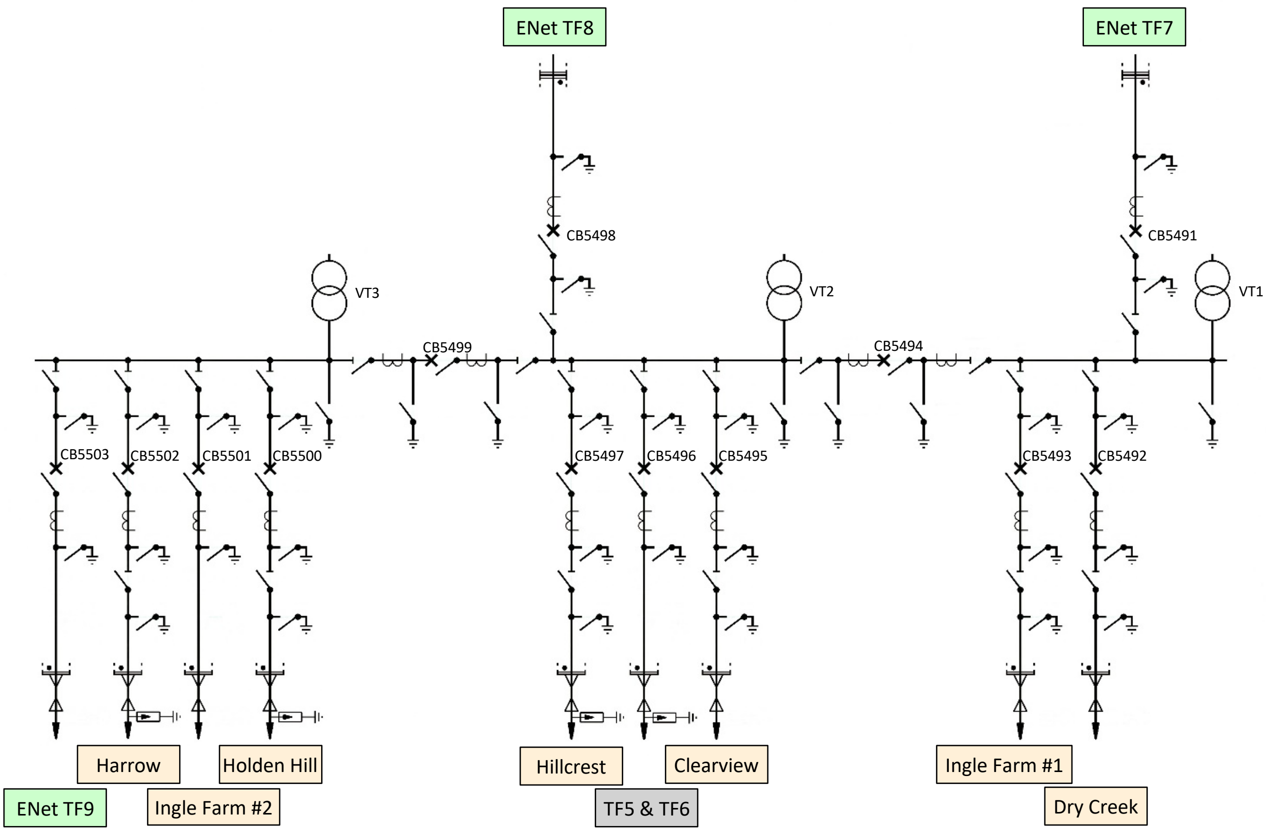


2.2 Design of the Northfield GIS

The Northfield substation is classified as a connection point substation because it is a physical link between South Australia's transmission and distribution networks. It contains an outdoor air-insulated switchgear (AIS) installation operating at 275kV owned by ElectraNet and an outdoor GIS installation operating at 66kV majority owned by SA Power Networks. These installations consist of three 275/66kV transformers supplying seven 66kV sub-transmission lines to Adelaide's eastern suburbs and the surrounding Northfield and Northgate areas via two 66/11kV transformers.

The present 66kV GIS installation at Northfield is configured into three basic bus sections, with the bus sections linked together through a circuit breaker and associated disconnect switches. Each bus section has the provision to connect a maximum of four external sources (one incomer and up to three outgoing connections), with each connection achieved through a circuit breaker and associated disconnect switches. Figure 2.2 provides an overview of the existing configuration of the Northfield GIS.

Figure 2.2: Simplified line diagram of the Northfield GIS configuration



Functionally, the Northfield GIS is used primarily to inject power into SA Power Networks' eastern suburbs 66kV network. To do this, it takes power from the three 275/66kV ElectraNet transformers on site and directs it into the 66kV network via seven sub-transmission lines also located in the substation. The output of these transformers is fed into the 11kV feeder network surrounding the substation via SAPN's two 66/11kV transformers 5 and 6.

The switchboard high voltages are insulated using gas (specifically SF_6), which is used extensively in the industry as an insulator and an arc interruption medium in gas insulated switchboards, cubicles, circuit breakers and other switchgear components. Within the switchboard, flanges are used to connect separate sections of switchgear with O-ring seals to contain the gas in separate chambers. The separate chambers have gas injection ports to enable the chambers to be filled with gas or for topping up should gas leaks occur. The gas is critical for the functioning of the electricity equipment and if low pressure occurs SCADA alarms are raised. If a sudden loss of gas was to occur the circuit breakers would attempt to isolate the faulted section. If any of the circuit breakers failed, supply to all 115,000 customers could be lost and the GIS could be damaged beyond repair.

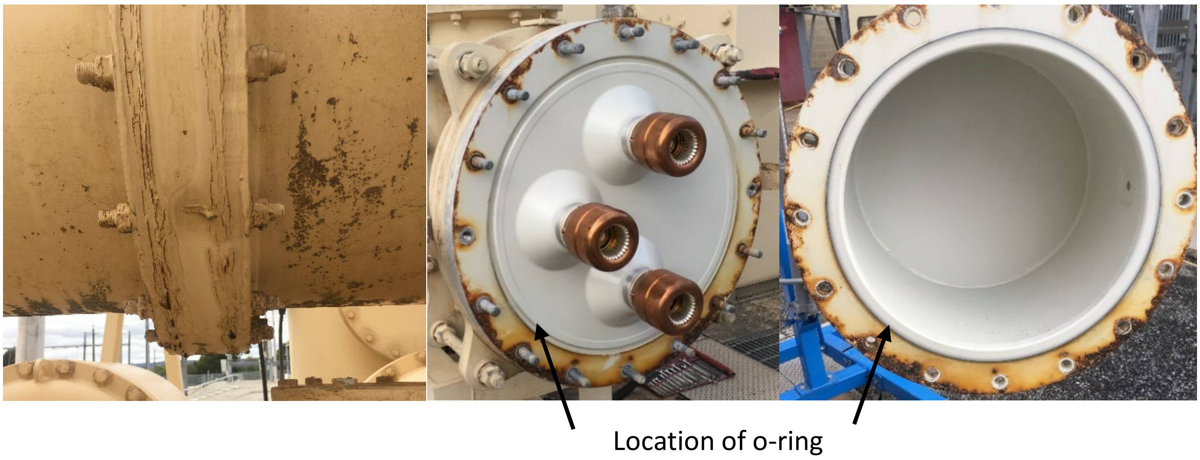
A critical element of the design is the rubber gas seal that holds the gas within the chambers. The equipment at Northfield GIS was designed with one sealing O-ring between the flanges instead of two sealing O-rings that other manufacturers adopted at the time, and which is currently design practice for GIS. The double seal is superior to a single seal for two key reasons:

- it provides higher protection against leaks; and
- if leaks do occur, the repairs are more likely to be successful.

2.2.1 Condition of the aging O-ring seals is leading to risk of gas leakages

O-ring seals age over time and become brittle, with the rate of ageing increasing with higher operating temperatures. The outdoor installation of the switchboards at Northfield GIS has meant that, after 35 years of continuous operation, the O-ring seals and flanges are in poor condition and a material risk of failure. In particular, the flanges are severely corroded – figure 2.3.

Figure 2.3: Condition of O-rings in the Northfield GIS



The condition of the O-rings are such that SA Power Networks is already experiencing seal failures. In April 2017, there were seal failures at two flanges that resulted in uncontrolled atmospheric gas leaks. In September 2019, seal failure occurred on a third flange. The leaks were caused by increasing corrosion on the flange surface and further leaks are expected which will compromise the integrity of the switchgear.

2.2.2 Attempts at refurbishing/repairing the seals have been unsuccessful

SA Power Networks has attempted to address the gas leaks and moisture ingress resulting from the severe external corrosion of the O-rings by refurbishing/repairing the seals. The attempts to provide sealing to stop the leaks was carried out by the manufacturer (Hitachi) in October 2018, which aimed to prolong the asset's useful life.

The repair works for one of the leaks at one of the metal-to-metal flanges was successful. The repair works for the second gas leak at a metal-to-board-to-metal flange took two attempts to seal the leak. However, in January 2019, a gas leak appeared at the same joint. The metal-to-board-to-metal flange repair has been unsuccessful since and more severe leakage of gas has occurred compared to the original gas leak. An additional gas leak at a third flange was identified in September 2019.

In July 2019, Hitachi advised that it is unable to provide the same repair solution to address the more recent leaks because it was no longer viable. SA Power Networks subsequently engaged BLJ In-Situ Solutions to attempt further repair works on the leaks (three attempts, the last in May 2022), all of which have been unsuccessful. Today the flange continues to leak SF_6, requiring the constant addition of gas to maintain pressure and keep the GIS in service.

2.3 Expected unserved energy if action is not taken

If investment is not undertaken, there will be significant unserved energy (USE) in SA Power Networks' distribution network because the asset condition will continue to deteriorate increasing the prospect of GIS failure. However, the extent of load at risk depends on the nature of the failure. SA Power Network has therefore considered three significant failure scenarios:

- Scenario 1: an event where a single GIS bus section fails;
- Scenario 2: an event where a failure causes two GIS bus sections to be inoperable, such as the failure of the circuit breaker connecting two adjacent bus sections; and
- Scenario 3: an event where failure results in total loss of Northfield GIS.

In developing each of these scenarios, SA Power Networks has assumed that the failed GIS is non-repairable and cannot be returned to service – triggering replacement that takes at least two years, which results in on-going load at risk during this replacement period, as well as the immediate load-shedding during the failure event. SA Power Networks' experience has been that even slow leaks cannot be repaired in some cases.

In estimating the load at risk, SA Power Networks has used the average load from 2018/19 of 89.15 megawatts (MW), because more recent data does not accurately represent future loads due to the effects of COVID-19 and mild summers. 10 per cent probability of exceedance (POE) forecast values were also used with a total peak load of 357MW. It was also assumed there is a total of 113,666 customers resulting in 318.4 customers per MW.

2.3.1 Scenario 1 – single Northfield 66kV bus section failure

Scenario one considers an event where a single GIS bus section fails, such as the loss of the centre bus section (identified as TF8 in figure 2.2 above). Under this scenario, SA Power Networks has contingency response plans in place to re-establish supply from the substation within a 24-hour period. Northfield and Clearview substations are restored via bypasses and offloads. 24 hours after the initial event, there is no on-going load at risk, however, there is a significant N-1 risk because of the single GIS bus section failure.

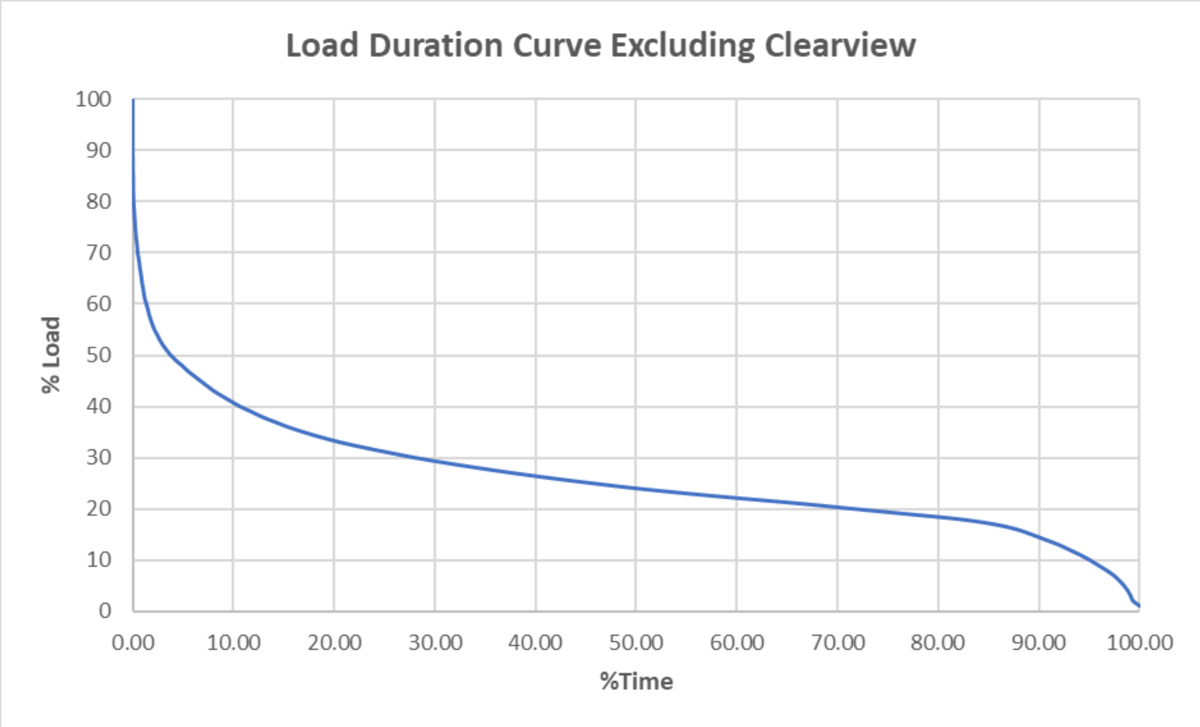
2.3.2 Scenario 2 – two Northfield 66kV GIS bus section failures

Scenario two considers an event where there are two GIS bus section failures, such as a leak on a section circuit breaker chamber or the centre section as well as a subsequent leak on the TF9 section (see figure 2.2).

Following such a fault the Clearview, Northfield 11kV and Harrow substations would experience an outage, resulting in the Magill to Campbelltown and Northfield to Ingle Farm 1 lines supplying the entire load in the area. These lines would be supplying the entire load in the north-east and have a total emergency rating of 281MW, meaning they can support all load initially before the restoration of the affected substations.

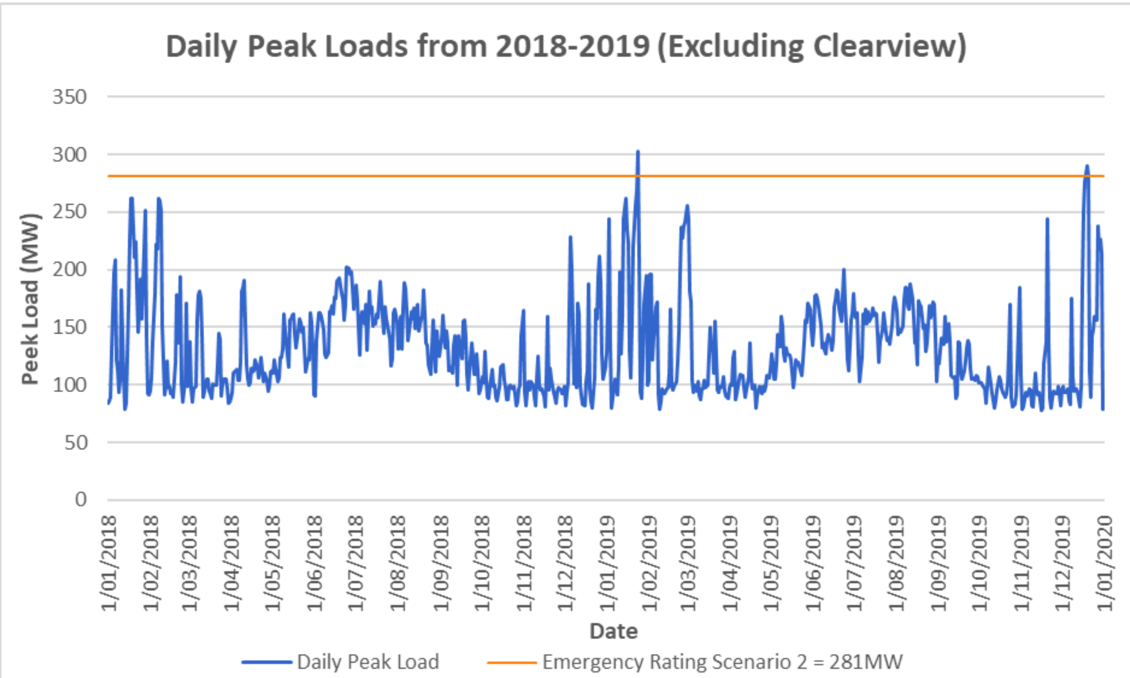
After 24 hours the Clearview, Northfield 11kV and Harrow substations would be restored via bypasses or 11kV load transfers. However, there would be an ongoing risk of unserved energy during the two-year replacement period because the nature of the supply restoration is such that network would not be able to meet peak demand in the area. SA Power Networks notes that Clearview would be restored via the Dry Creek 66kV line which would then result in it being supplied outside of the constrained eastern suburbs interconnected network. It has therefore been excluded from the load duration curve underpinning the assessment of load at risk during the replacement period under this scenario – figure 2.4.

Figure 2.4: Load duration curve under Scenario 2



Based on the load duration curve in figure 2.4, the amount of time the Magill to Campbelltown and/or Northfield to Ingle Farm # 1 lines would be overloaded prior to the replacement of the failed bus sections is 0.08 per cent – or eight hours at risk per 10 per cent POE year, implying that load shedding would be required for three days – figure 2.5.

Figure 2.5: Daily peak loads from 2018/19

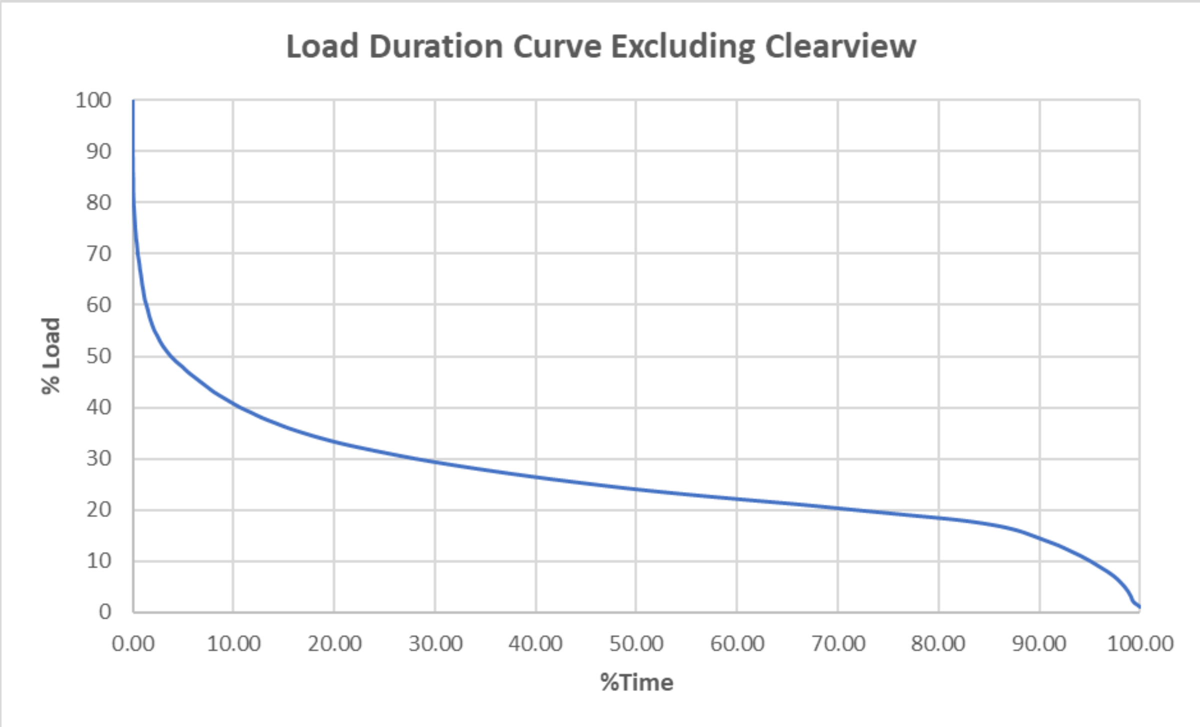


2.3.3 Scenario 3 – total loss of Northfield 66kV GIS

Scenario 3 considers the total loss of the Northfield GIS. SA Power Networks considers this is a credible risk due to the poor condition of the asset and large number of joints with the potential to leak on the GIS. In particular, two or more significant leaks on different bus sections could cause this scenario, leading to complete failure of the asset.

Depending on the particular nature of the failure, any radial load lost would be restored within 24 hours of the initial fault. Specifically, Clearview, the Northfield 11kV and Harrow substations would be restored via bypasses or 11kV transfers. However, similar to Scenario 2, there would be an ongoing risk of unserved energy during the two-year replacement period because the nature of the supply restoration is such that network would not be able to meet peak demand in the area. Clearview would again be restored via the Dry Creek 66kV line and therefore supplied outside of the eastern suburbs 66kV interconnected network and it has therefore been excluded from the load duration curve underpinning the assessment of load at risk under this scenario – figure 2.6.

Figure 2.6: Load duration curve under Scenario 3



Under this scenario the only supply into the eastern suburbs 66kV interconnected network is the Magill to Campbelltown 66kV line (Northfield to Ingle Farm # 1 is no longer available due to the complete loss of the GIS). Drawing on the load duration curve presented in figure 2.6, this line would be overloaded 8.1 per cent or 707 hours per POE10 year. In particular, during peak load periods there would be 332MW of demand compared to the 142MW emergency rating of the line – implying an overload of 134 per cent which translates to a 190MW supply shortfall. Further, peak load at Northfield substation would likely exceed the emergency rating of the line on 140 days – figure 2.7.

Figure 2.7: Daily peak loads from 2018/19

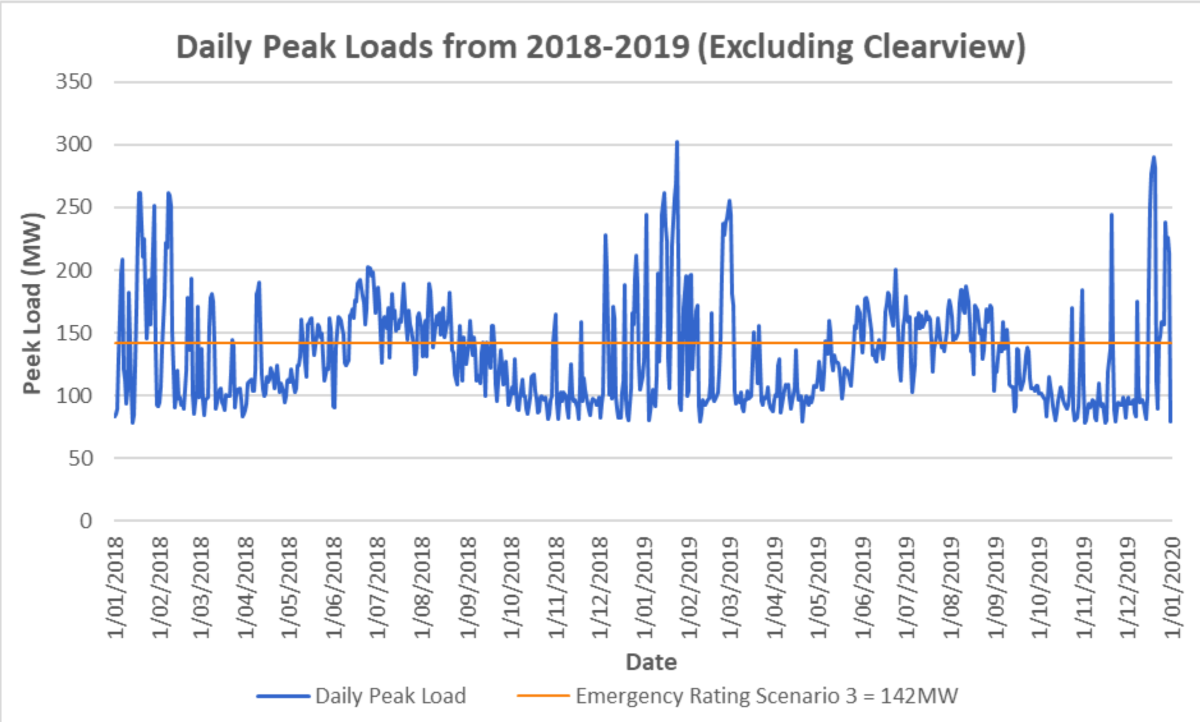
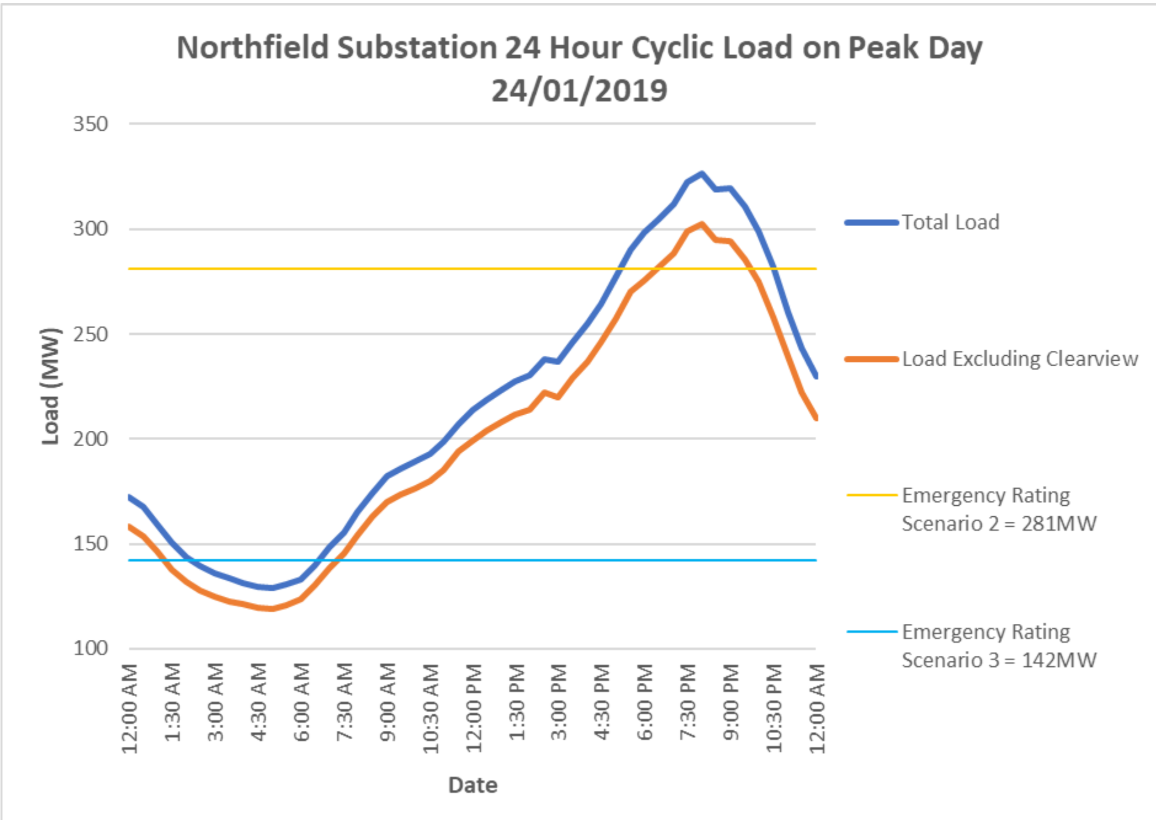


Figure 2.8 presents the peak load profile for a summer day at Northfield substation and compares this profile to the emergency rating of the available lines under Scenarios 2 and 3, illustrating that network support would be required for the majority of the day during the summer period irrespective of the failure scenario (with the exception of Scenario 1).

Figure 2.8: Peak summer day profile for Northfield substation



2.4 Environmental Impact

The Northfield 66kV GIS is currently leaking significant volumes of SF_6 gas into the atmosphere from known leak points. The leak rate is highly likely to increase as more leaks develop and the existing unrepairable leaks deteriorate further. SF_6 gas is the most potent greenhouse gas known, approximately 23,000 times worse than CO_2.

In the financial year 2020-2021, the annual emission of SF_6 amounted to approximately 76kg from Northfield Substation alone, adversely contributing to climate change. It is likely the condition of the GIS will continue to deteriorate, increasing the rate of uncontrolled SF_6 release into the atmosphere.

SA Power Networks acknowledges that environmental impacts are not an assessment factor in the RIT-D process, but the company environmental policy recognises that SF_6 losses should be minimised and its use discontinued owing to the significant negative environmental impact. There are also reputation risks faced by SA Power Networks (and potentially the broader electricity sector) because of releasing SF_6, and there is growing pressure internationally to ban the use of this gas.

3 Proposed network options to meet the identified need

SA Power networks has identified two credible network options to address the identified need. This section provides more information on the scope and cost of these options. It also outlines options considered but that SA Power Networks does not propose to progress further.

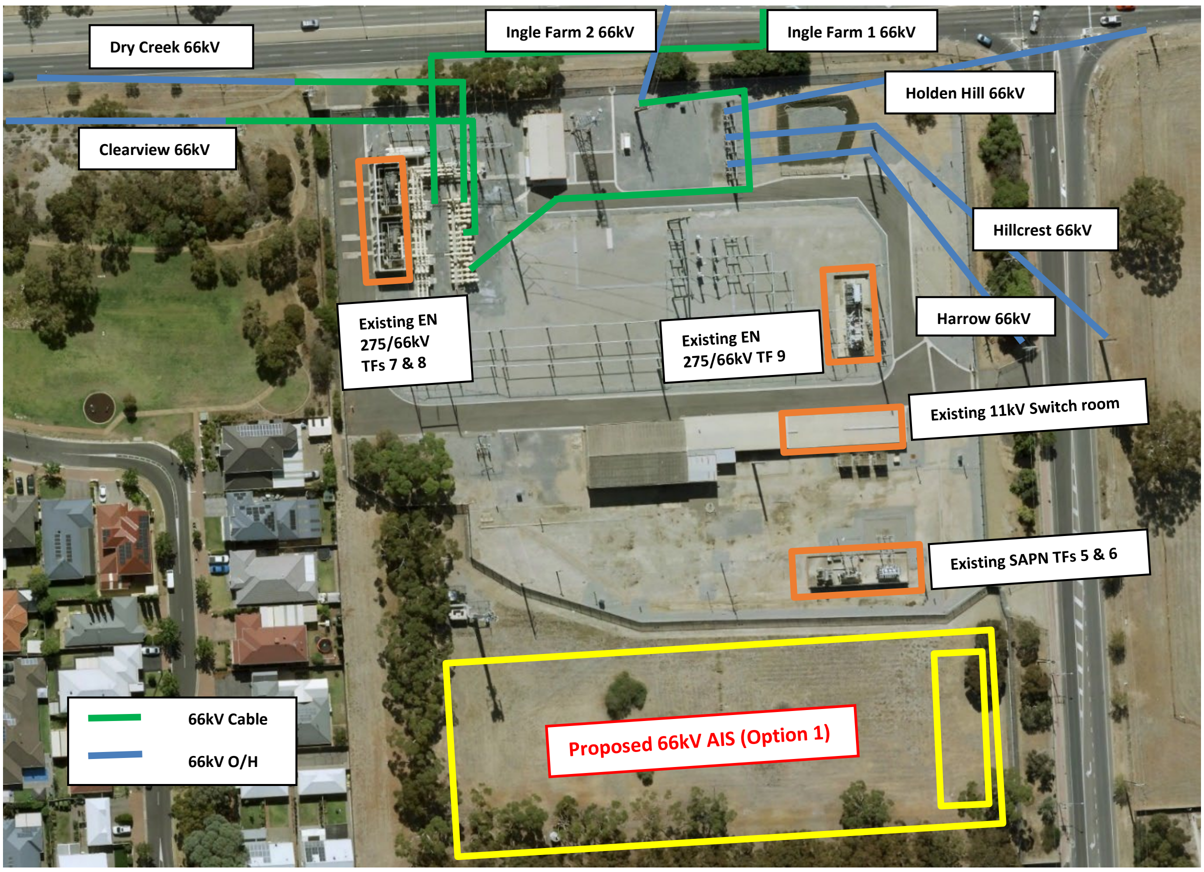
3.1 Option 1 – Construct a new Northfield 66kV AIS

Option 1 involves constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation. In particular, the outdoor AIS would comprise:

- three 275/66kV transformer connections;
- three 66kV bus sections with ring bus cable tie;
- seven 66kV line exits, with provision for nine exits in total;
- connection to the existing 66/11kV transformers at Northfield substation, with provision for three additional transformers; and
- building characteristics that are capable of accommodating future 11kV upgrades to meet capacity constraints (forecast to be required by 2030).

Figure 2.9 provides an overview of the layout of Northfield substation under this option.

Figure 2.9: Layout of Northfield AIS under Option 1



The total cost of this option is expected to be $45.5 million, including approximately $15M in transmission (ElectraNet) capex. Construction of the new AIS would commence in 2023 with commissioning of the asset completed in 2025.

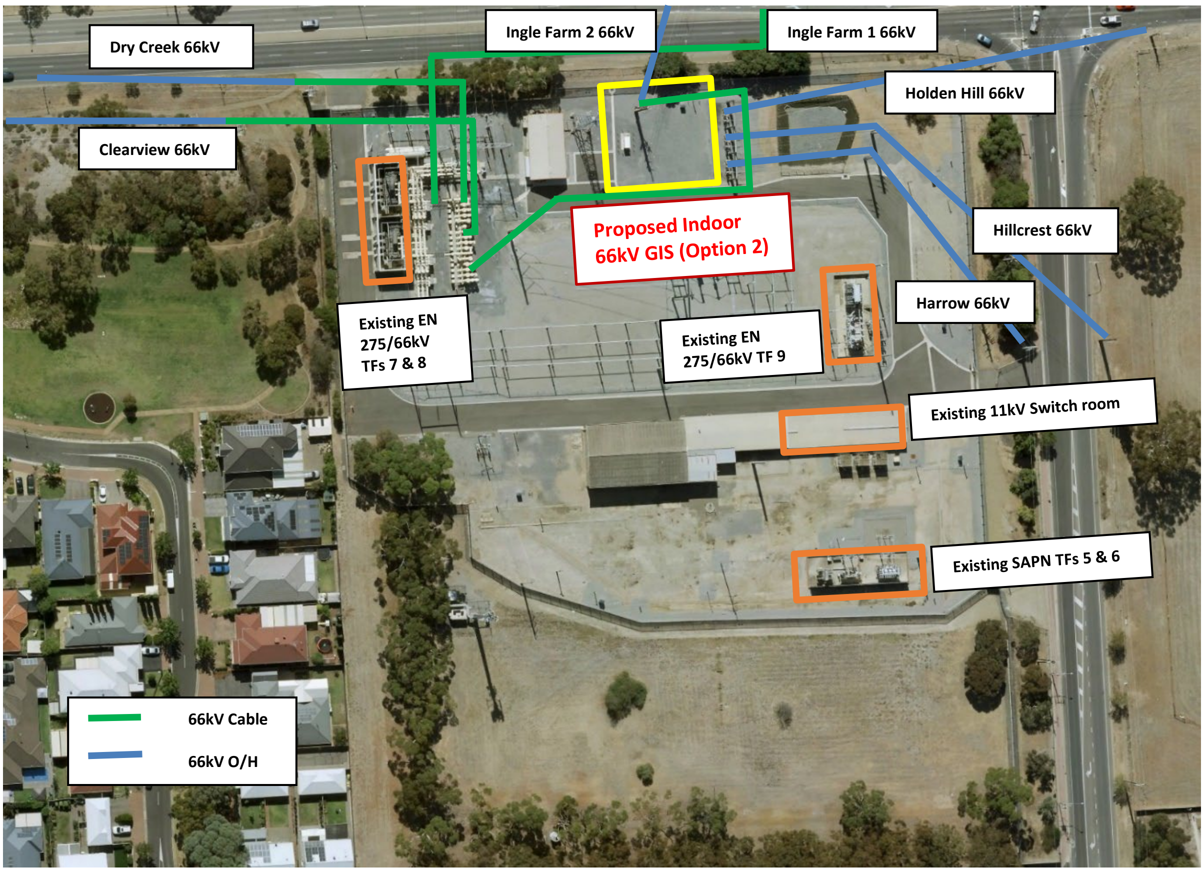
3.2 Option 2 – Construct a new indoor Northfield GIS

Option 2 involves constructing a new three section 66kV GIS in a climate-controlled building in the northeast corner of the Northfield substation. The new GIS would be housed indoors to minimise the potential for corrosion and thereby avoid the present asset condition issues. Within the climate-controlled building the GIS would comprise:

- three 275/66kV transformer connections;
- three 66kV bus sections with ring bus cable tie;
- seven 66kV line exits, with provision for nine in total; and
- connection to the existing 66/11kV transformers at the Northfield substation, with provision for three additional transformers.

In contrast to Option 1, the building characteristics would not be capable of accommodating future 11kV upgrades to meet network constraints forecast to arise by 2030. Figure 2.10 provides an overview of the layout of Northfield substation under this option.

Figure 2.10: Layout of Northfield indoor GIS under Option 2



The total cost of this option is expected to be $47.0 million, including approximately $11M in transmission (ElectraNet) capex. Construction of the new indoor GIS would commence in 2023 with commissioning of the asset completed in 2025.

3.3 Options considered but not proposed to be progressed in the FPAR

Section 2.2.2 describes the various approaches SA Power Networks has adopted to address the asset condition issues of the existing Northfield GIS, none of which have proven to be successful over an extended period.

SA Power Networks engaged EA Technology, a British engineering firm with significant experience in GIS management, to complete an engineering assessment of the management of the existing Northfield GIS including its condition, previous repair attempts and future options to be explored.

EA Technology's assessment recommended that the least intrusive solution to customer supply, lowest risk for supply interruptions and best solution for environment protection is replacement of the existing GIS switchboard. SA Power Networks has therefore not considered alternative approaches that do not involve replacement of the switchboard. Rather, the focus of the RIT-D assessment is on the most efficient technical means of replacing the switchboard.

4 Assessment of non-network solutions and SAPS

SA Power Networks has determined that there is unlikely to be a non-network option or SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of a potential credible option for this RIT-D. Furthermore, no submissions were received during the consultation period for the DPAR for a non-network or SAPS solution.

This section sets out the assessment for a non-network or SAPS solution, which draws on the assumptions outlined in the sections above, and considers the required technical characteristics required in order to meet the identified need.

4.1 Requirements that a non-network option or SAPS would need to satisfy

A viable non-network option or SAPS that maintains supply to all customers in the eastern suburbs must be capable of reducing the estimated shortfall in the supply capability of the network in the event of a failure of the Northfield GIS. It should also be capable of providing the entire peak demand of the area to provide security of supply to the network as it operates in contingent conditions.

As discussed in section 2.3, there are number of failure scenarios that will affect the size of load reduction or additional supply required from a non-network option or SAPS option. SA Power Networks considers that any non-network option or SAPS option must be capable of alleviating the shortfall in supply in the worst-case scenario, i.e., total loss of the Northfield GIS (Scenario 3). Non-network options or SAPS options must therefore be able to address this failure scenario to be able to address the identified need. Being able to address the complete loss of the Northfield GIS would also ensure that any non-network or SAPS option could manage the other failure scenarios.

This section therefore focuses on the requirements that a non-network option or SAPS would need to satisfy in the event of a complete loss of the Northfield GIS.

4.1.1 Requirements to address complete loss of the Northfield GIS

Under Scenario 3 the only supply into the eastern suburbs 66kV interconnected network is the Magill to Campbelltown 66kV line. Drawing on the load duration curve presented in figure 2.6, this line would be overloaded 8.1 per cent or 707 hours per POE10 year. In particular, during peak load periods there would be 332MW of demand compared to the 142MVA emergency rating of the line – implying an overload of 134 per cent which translates to a 190MW supply shortfall.

Figure 2.8 in section 2.3.3 also demonstrates that on a peak summer day demand at the Northfield substation would exceed the emergency rating of the line for the majority of the day.

The analysis above illustrates that the requirement for support from non-network options and SAPS is substantive in both the numbers of days expected to be required and the magnitude of the support needed. In particular, it demonstrates that the required characteristics of a non-network or SAPS option to represent a credible option for this RIT-D is an order of magnitude that does not appear realistic (given the scale of assistance needed).

4.1.2 Consideration of SAPS options

Recent changes to the NER, RIT-D and RIT-D application guidelines require SA Power Networks to consider whether a SAPS option can fully or partly address an identified need. In practice, this relates to consideration of whether an identified need could be fully or partly addressed by converting part of SA Power Networks’ distribution network forming part of the interconnected national electricity system to a regulated SAPS.[1] Regulated SAPS are set out in section 6B of the National Electricity Law (NEL), which defines a SAPS as a system that:[2]

- generates and distributes electricity; and
- does not form part of the interconnected national electricity system.

SA Power Networks considers that there is not a SAPS option that could form a potential credible option on a standalone basis, or that could form a significant part of the credible option, in this RIT-D. In particular, the load requirements of the eastern suburbs interconnected network are significant and could not be supported by a network that is not part of the interconnected national electricity system with the ability to draw on grid-connection generation services.

5 How the options have been assessed

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

5.1 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, SA Power Networks will escalate regular and corrective 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 2023 to 2042. SA Power Networks considers that a 20-year period considers the size, complexity and expected life of the relevant credible option to provide a reasonable indication of the market benefits and costs of the option. While the capital components of the credible option have asset lives greater than 20 years, SA Power Networks has taken a terminal value approach to incorporate capital costs in the assessment, which ensures that the capital cost of long-lived options is appropriately captured in the 20-year assessment period.

The commercial rate determined by the Australian Energy Market Operator (AEMO) from its Integrated System Plan has been used as the central discount rate, which is currently 5.5%. This is a rate that reflects an energy business operating in the NEM. The high benefit discount rate has been set at 2.34%, reflecting the latest Australian Energy Regulator (AER) WACC determinations for DNSPs. The high discount rate determined by AEMO from its ISP has been used as the low benefit discount rate, which is currently 7.5%.

5.2 Approach to estimating project costs

SA Power Networks has estimated capital costs through formal estimations conducted by estimation experts within the business. Where possible, SA Power Networks has also estimated capital costs using supplier quotations or other pricing information.

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

[1] See definition of 'SAPS option' in the NER.
[2] Section 6B(6) of the NEL.

Operating costs have been estimated for the credible option and the base case by considering:

- the probability and expected level of 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.

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.

5.3 Benefits expected from avoided involuntary load shedding

SA Power Networks considers the relevant categories of market benefits prescribed under the NER for this RIT-D relate to changes in involuntary load shedding. Other market benefits are considered immaterial to this RIT-D in comparison to involuntary load shedding.

The approach SA Power Networks has made to estimating reductions in involuntary load shedding are outlined in Sections 5.3.1, 5.3.2 and 5.3.3.

5.3.1 Avoided involuntary load shedding

Involuntary load shedding occurs when a customer's load is interrupted from the network without warning or their agreement. This can occur due to unavailability of network elements and the resulting reduction in network capacity to supply the load.

The Unserved Energy (USE) is the probability weighted average amount of load that customers request to utilise but would need to be involuntarily curtailed due to loss of network connectivity or a network capacity limitation. SA Power Networks has forecast load over the assessment period and has quantified the USE 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 market benefit that results from reducing the involuntary load shedding with a network solution is estimated by multiplying the quantity of USE in MWh by the Value of Customer Reliability (VCR). The VCR is measured in dollars per MWh and is used as proxy to evaluate the economic impact of USE on customers under the RIT-D.

SA Power Networks has applied a central VCR estimate of $34,460/MWh, which is the value calculated for Climate Zone 5 CBD & Suburban SA by the AER in its 2021 VCR Annual Adjustment[3]. The AER also recommends using values of ± 30% of the base case VCR for the purposes of testing how sensitive investment decisions are to the VCR input[4]. A lower VCR of $24,122/MWh and a higher VCR of $44,798/MWh have been chosen for the low and high benefit scenarios, as a result.

5.3.2 Probability of 66kV GIS failure weights involuntary load shedding

SA Power Networks has developed a probability model to estimate the expected probability of failure for the GIS at Northfield.

[3] AER, 2021 VCR Annual Adjustment, 2021, available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20customer%20reliability%20%20update%20summary%20-%20December%202021%2813309497.1%29.pdf

[4] AER, Values of Customer Reliability Review – Final Report on VCR values – December 2019, available at https://www.aer.gov.au/system/files/AER%20-%20Values%20of%20Customer%20Reliability%20Review%20-%20Final%20Report%20-%20December%202019.pdf

The model considers the three failure modes of Section 2.3, using three independent normal distribution curves centred on conservative expectations of time to failure. Specifically, the central scenario uses mean years of 2027, 2034 and 2041 respectively. The USE is derived from the weighted sum of the three failure scenarios.

The low and high benefits scenarios were calculated by adjusting the mean failure year of the three scenarios up and down respectively.

5.3.3 Capping of unserved energy

SA Power Networks has capped the expected future USE at 5,000 MWh for any given year because the uncapped value of USE will otherwise become unrealistically high (in reality, SA Power Networks would undertake investment to avoid widespread customer outages). Using the very large, uncapped USE values has the potential to distort the comparison of net market benefits between credible options. The approach of capping USE in the base case is in-line with other RIT-Ds (and RIT-Ts) and does not affect the ranking of the overall options.[5,6]

5.4 Scenarios to address uncertainty

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.

SA Power Networks has elected to assess three alternative future scenarios – namely:

- Central Benefits Scenario – the central scenario consists of assumptions that reflect SA Power Networks’ central set of variable estimates which, in SA Power Networks’ opinion, provides the most likely scenario;
- Low Benefits Scenario – SA Power Networks has adopted a number of assumptions that give rise to a lower bound 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 the credible option; and
- High Benefits Scenario – this scenario reflects an optimistic set of assumptions, which have been selected to investigate an upper bound on reasonably expected market benefits.

A summary of the key variables in each scenario is provided in Table 5.1.

[5] SA Power Networks note that this is also consistent with the approach proposed by Dr Biggar in his review of the Powering Sydney’s Future RIT-T (see: Biggar, D., An Assessment of the Modelling Conducted by TransGrid and Ausgrid for the “Powering Sydney’s Future” Program, May 2017, p. 27). While Dr Biggar suggests capping the ‘congestion cost’ (calculated as the unserved energy valued at the VCR) in such assessments, we consider it more intuitive to cap the underlying unserved energy, in MWh. This is the approach that has been adopted by other DNSPs and is effectively equivalent to the approach proposed by Dr Biggar.

[6] See for example: Ausgrid, Ensuring reliable supply for the Sydney Airport network area, Final Project Assessment Report, 6 March 2020, p. 15.

Table 5.1: Summary of three scenarios investigated; Central, Low and High Benefits

Variable	Central Scenario	Low Scenario	High Scenario
Discount Rate	5.5%	7.5%	2.34%
VCR	$34,460/MWh	$24,122/MWh	$44,798/MWh
Capital Costs	100% of capital cost estimate	125% of capital cost estimate	75% of capital cost estimate
Unplanned Corrective Maintenance	100% of unplanned corrective maintenance estimate	75% of unplanned corrective maintenance estimate	125% of unplanned corrective maintenance estimate
Avoided Involuntary Load Shedding	100% of avoided involuntary load shedding estimate	75% of avoided involuntary load shedding estimate	125% of avoided involuntary load shedding estimate

SA Power Networks considers that the Central Scenario is the most likely, since it is based on a set of central assumptions. SA Power Networks has therefore assigned this scenario a weighting of 50 per cent, with the other two scenarios being weighted equally with 25 per cent each. SA Power Networks notes, however, that the identification of the preferred option is the same across all three scenarios, i.e., the result is insensitive to the different scenario weights.

6 Assessment of the credible options

This section provides a description of the credible network options SA Power Networks has identified as part of its network planning activities to date. The option is compared against a base case option.

6.1 Gross market benefits estimated for the credible options

Table 6.1 below summarises the gross benefit of the credible options relative to the base case in present value terms. The gross market benefit for each option has been calculated for each of the three scenarios outlined in Section 5.

Table 6.2: Present value of Benefits of credible options relative to the base case, $m 2022/23

Variable	Central Scenario	Low Scenario	High Scenario
Scenario Weighting	50%	25%	25%
Option 1: New Outdoor AIS	872.0	156.2	3,083.9
Option 2: New Indoor GIS	872.0	156.2	3,083.9

6.1.1 Unquantified benefits

SA Power Networks has also identified the following unquantified benefits which have not been included within the present value summary of benefits in Table 5.2 – namely:

- Lower whole of life site capex considering a future 11kV upgrade.
- Option 1 is modular in design. Faulted components can be replaced individually reducing operational costs and increasing overall asset life.
- Option 1 has a longer design life than Option 2 and
- Option 1 is built from standard components which SA Power Networks frequently deploys and has 'in-house' expertise to install and maintain.

6.2 Estimated costs for the credible options

Table 5.3 below summarises the costs of the credible options relative to the base case in present value terms. The cost is the sum of the project capital costs and the operating costs associated with running and maintaining the existing GIS. The cost of each option has been calculated for each of the three scenarios, in accordance with the approaches outlined in Section 5.

It is important to note that the difference in estimated costs will determine the preferred option, as the benefits of both options are the same as per Table 6.2.

Table 6.2: Present value of Costs of credible options relative to the base case, $m 2022/23

Variable	Central Scenario	Low Scenario	High Scenario
Scenario Weighting	50%	25%	25%
Option 1: New Outdoor AIS	-26.7	-39.5	-9.9
Option 2: New Indoor GIS	-30.0	-42.7	-13.8

6.3 Net present value assessment outcomes

Table 6.3 below summarises the net market benefit in Net Present Value (NPV) terms for the credible options under each scenario. The net market benefit is the gross market benefit (as set out in Table 6.1) minus the cost of the option (as set out in Table 6.2), all in present value terms. Overall, Option 1 exhibits the highest estimated net market benefit.

Table 6.3: Present value of weighted net benefits relative to the base case, $m 2022/23

Option	Weighted PV of costs	Weighted PV of gross benefits	Weighted NPV	Ranking
Option 1: New Outdoor AIS	-25.7	1,246.0	1,220.3	1
Option 2: New Indoor GIS	-29.1	1,246.0	1,216.9	2

6.4 Sensitivity analysis results

SA Power Networks has undertaken a sensitivity testing exercise with two steps to understand the robustness of the RIT-D assessment to underlying assumptions of key variables:

- Step 1 - testing the sensitivity of the optimal timing of the project to different assumptions in relation to key variables, and
- Step 2 - once the optimal timing year has been determined in step 1, testing the sensitivity of the NPV associated with the investment proceeding in that year.

That is, SA Power Networks has undertaken sensitivity analysis to first determine the optimal timing of the project, and to then confirm the NPV of Option 1 is insensitive to the range of other variables tested.

6.4.1 Step 1 - Sensitivity testing of the assumed optimal timing for the credible option

SA Power Networks has estimated the optimal timing for each option based on the commissioning year in which the NPV of each option is maximised. This process was undertaken for both the baseline set of assumptions and a range of alternative assumptions for key variables – namely:

- low and high discount rates
- low and high capital costs
- low and high operational costs
- low and high risk costs
- low and high VCR
- low and high benefits

It was found that for the baseline and each of the above alternative assumptions, the optimal commissioning year is in 2025.

6.4.2 Step 2 - Sensitivity of the net market benefit

SA Power Networks has also conducted sensitivity analysis on the NPV of the net market benefit, based on the assumed option timing established in step 1. The same key variables listed in step 1 have been used.

It was found that the NPV of the net market benefit is insensitive to all other variables once the optimal timing year has been determined.

7 Proposed preferred option

SA Power Networks proposes Option 1, to construct a new Northfield 66kV AIS, is the preferred option which satisfies the RIT-D. This option involves constructing a new 66kV outdoor AIS immediately south of the existing Northfield substation with three 66kV bus sections supplying all existing seven 66kV lines as well as supplying the two 66/11kV transformers at the existing Northfield substation.

Construction of the new AIS would commence in 2023 with commissioning completed in 2025.

SA Power Networks considers that detailed analysis within this FPAR identifies Option 1 as the preferred option and that this satisfies the RIT-D. SA Power Networks is the proponent for Option 1.