

Retirement of Sadadeen 22 kV switchboard

Final Project Assessment Report

Final Project Assessment Report under clause
5.17.4(n) of the Northern Territory National
Electricity Rules

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1. Summary

This is Power and Water Corporation's (Power and Water) Final Project Assessment Report for the retirement of the 22 kV switchboard at Sadadeen zone substation. As stated in the Non-Network Options Notice (the Notice), we found there are no credible non-network options or stand-alone power systems (SAPS)¹ options to address all or part of the identified need at Sadadeen (SD) zone substation. We have made the determination under clause 5.17.4(c) of the NT National Electricity Rules (NT NER) and published the Notice pursuant to clause 5.17.4(d).

Pursuant to clause 5.17.4(n), we have progressed directly to the Final Project Assessment Report based on the estimated cost of the preferred option being less than the threshold of \$12 million specified by the Australian Energy Regulator (AER)².

1.1 Identified network issue

The 22 kV switchboard at Sadadeen zone substation in Alice Springs is at end of life. The primary network issue is deteriorated condition of the 22 kV switchboard as identified by increasing partial discharge³ on the switchboard bus. Compounding the issue are:

- a depleted level of spare parts to maintain the asset
- long lead times to obtain spare parts
- several recent asset failures and failure history associated with this type of switchboard
- condition issues with associated assets including the distribution feeder protection relays and the switchboard building.

Poor asset condition has been managed operationally since 2008. Spare parts are now depleted and obtaining new parts has a lead time of 3 to 6 months as they need to be custom made. It is not possible to continue to maintain the asset.

The consequences of asset failure are reduced network security, safety risk to our field crews and capacity constraints resulting in significant outages to our customers.

1.2 Options assessment

We have identified 5 network solutions that were assessed to identify the option with the highest benefit to customers. We prefer Option 4, which involves decommissioning the 22 kV switchboard at Sadadeen zone substation and installing 2 new 22 kV cables. This option is preferred under all scenarios tested and has an expected Net Present Value (NPV) of \$111.4 million.

As determined in the Notice, we found no potentially credible non-network solutions and therefore no non-network options are included in this report.

¹ We note that a recent rule change requiring the consideration of SAPS is not operational under the NT NER.

² Australian Energy Regulator, 2021 RIT and APR cost thresholds review – Final Determination, November 2021, Table 3

³ Partial discharge is a localised arcing between 2 surfaces (an active phase and earth or 2 active phases) when there is insufficient insulation. The arcing does not completely bridge the gap/insulation between the 2 surfaces, hence being termed partial. It causes damage to the insulation so over time it will result in a fault occurring between the 2 surfaces.

1.3 Further information

As required by clause 5.17.4(j)(12) of the NT NER, please direct any questions regarding this notice or requests for further information to:

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2. Background

2.1 The Alice Springs network

The Alice Springs network is relatively small, compared to other networks in Australia, providing power to more than 10,000 residential households and almost 2,000 business customers. The MacDonnell Ranges pass along the south of Alice Springs and geographically splits the town into 2 regions. The suburb known as The Gap has a natural valley through the ranges and is the primary connection between the 2 regions, reflected in the configuration of the electricity network.

Figure 1 provides an indicative overview of the network⁴. Sub-transmission is supplied at 66 kV from Owen Springs Power Station (OSPS) to Lovegrove zone substation. North of The Gap is supplied at 11 kV and is comprised of the Alice Springs CBD, older commercial areas and the majority of residential customers. South of The Gap comprises predominantly commercial and industrial customers supplied at 22 kV. Most future load growth, including future residential development, is expected south of The Gap.

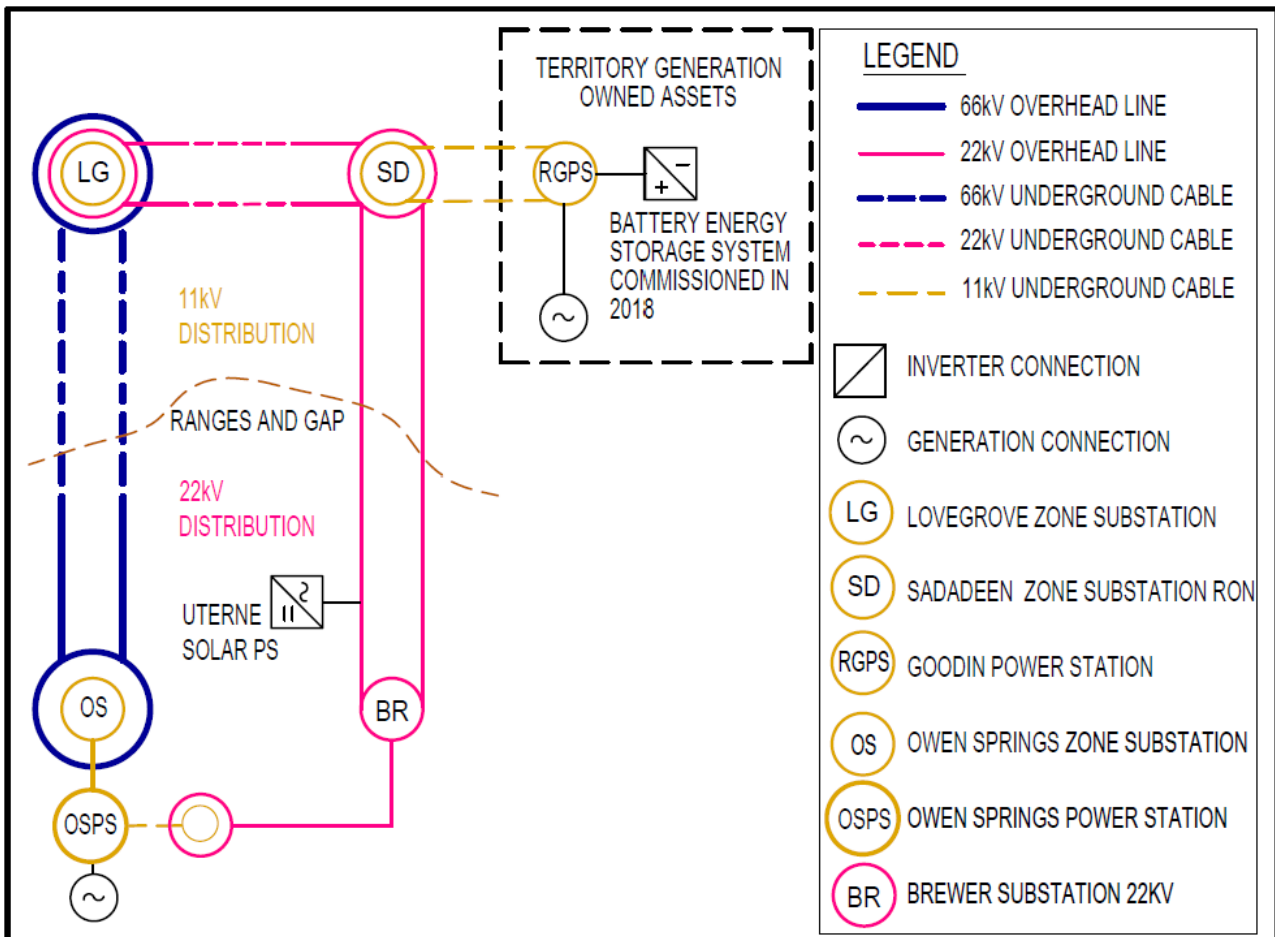


Figure 1: Simplified single line network diagram for Alice Springs

⁴ An aerial view of Alice Springs highlighting the impact of The Gap is shown in Figure 7 in Appendix A.

Prior to the construction of OSPS in 2011, Ron Goodin Power Station (RGPS) was the primary generator with support from the Brewer generator (now decommissioned) and the network consisted of 22 kV and 11 kV voltages. The 66 kV voltage level was introduced to connect OSPS to Lovegrove zone substation resulting in a more complex network topology.

The sub-transmission network provides the majority of capacity to Alice Springs. However there remains a 11/22 kV transformer at the decommissioned Brewer generation site that is supplied from OSPS to provide supply directly to the 22 kV network south of The Gap. The Brewer transformer is limited to approximately 8 MVA due to cable capacity constraints and to maintain control of network voltage.

2.2 Retirement of Ron Goodin Power Station

OSPS is the primary power station with a firm capacity of 90 MVA that is sufficient to supply the total demand of the network. As a result, Territory Generation's 2020-21 Statement of Corporate Intent has identified RGPS as being in transition to closure⁵.

Territory Generation (TGen) first identified plans for retirement of RGPS in their 2019-20 Statement of Corporate Intent. RGPS has remained in service due to system black requirements, however recent consultation has identified that the system black restart capability of OSPS is proven. There are no requirements to keep RGPS in service. It is predominately operated for maintenance purposes until it is decommissioned.

Additional issues contributing to the retirement decision include:

- Noise and pollution abatement due to encroachment of residential development.
- Government decision not to install any new generation at the RGPS site and locate all new generation at OSPS⁶.
- Deteriorated condition of the 1973 commissioned generators.
- Inefficiency of the generators and cost of the diesel fuel required.

While OSPS has sufficient capacity to meet the forecast demand at a whole of network level, with RGPS retiring, existing embedded generation capacity on the 11 kV and 22 kV network will decrease and result in potential constraints, as discussed in section 3.2.3.

2.3 Capacity to meet system demand

Figure 2 shows the load duration curve for the entire Alice Springs network. The load duration curve is calculated from 30-minute load data from 1 July 2020 to 30 June 2021 and shows the period time, as a percentage of the year that the load on the network exceeds the corresponding demand on the y-axis.

The N capacity represents the capacity available with all transformers in service, namely the two 66/22 kV 45 MVA transformers at Lovegrove zone substation and the 11/22 kV 8 MVA Brewer transformer⁷. The N-1 capacity represents the capacity available if there is an outage on one of the 2 Lovegrove transformers.

⁵ Territory Generation, 2020/21 Statement of corporate intent, Page 23

⁶ NT News, Owen Springs to become new power base for Alice with \$75m expansion plan, Ron Goodin to shut, February 2016

⁷ The Brewer Transformer is supplied directly from OSPS at 11kV and steps up the voltage to 22kV, therefore it provides additional capacity to the Alice Springs system in addition to Lovegrove zone substation. It does not have a tap changer so is unable to effectively control network voltage and limits its use operationally.

The load duration curve shows that there is no load at risk from a whole of network perspective. However, as discussed in section 3.2.2, there is some load at risk at a local level within the network.

Figure 3 also shows that overall, there is no significant forecast demand growth in the next 10 years. The demand on the 11 kV network north of The Gap is forecast to decrease slightly while demand on the 22 kV network south of The Gap is forecast to increase slightly.

We have concluded there is insignificant risk regarding overall capacity to supply the Alice Springs network.

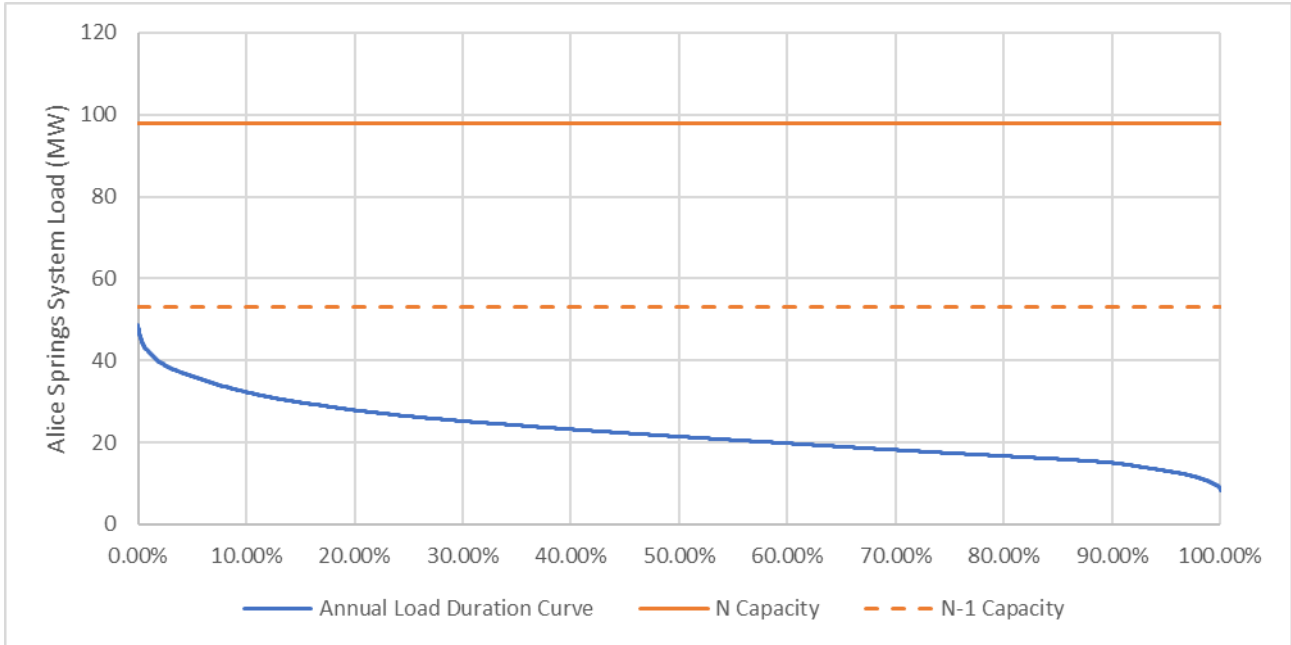


Figure 2: Load duration curve for the whole Alice Springs network for FY22

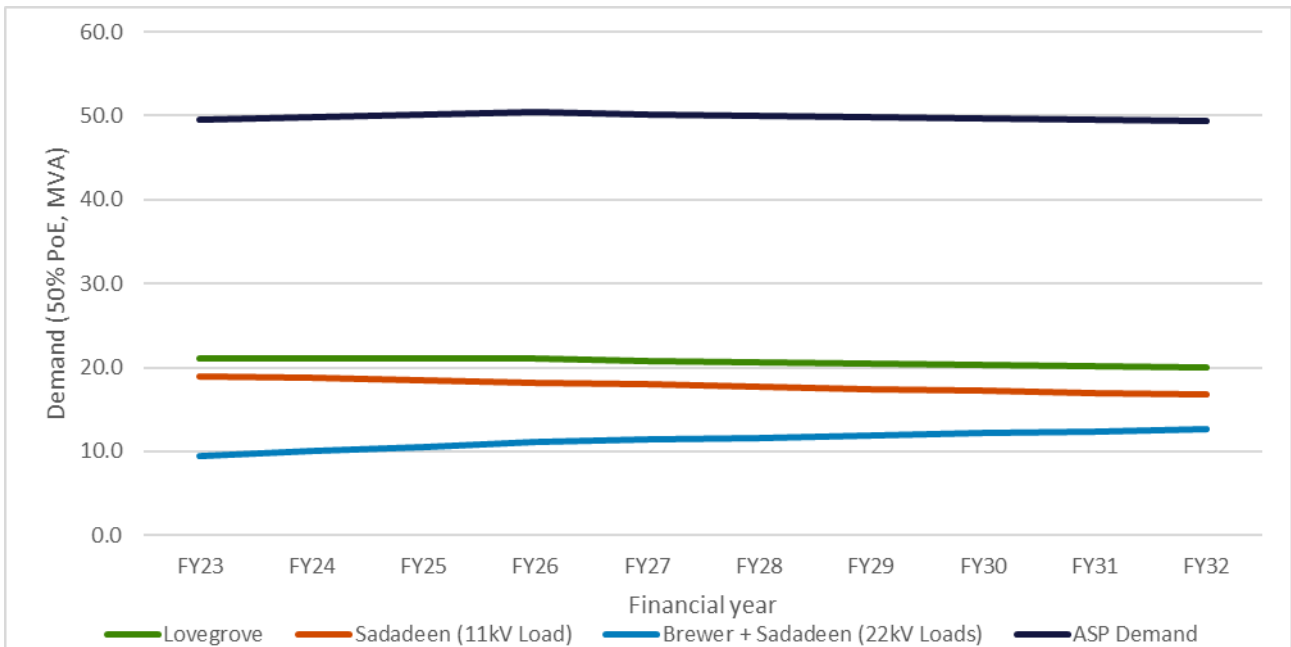


Figure 3: Forecast demand by zone substation and distribution voltage

2.4 Load transfer capability

The load transfer was considered under N, N-1 and N-2 scenarios. Failure of the Sadadeen switchboard, considered a credible event for the reasons described in section 3 below, would cause an N-2 scenario as it will result in total loss of supply at Sadadeen because both express ties supplying Sadadeen are connected at 22 kV, refer to Figure 4 below.

There is capacity at Lovegrove zone substation at 11 kV and on the 11 kV distribution network to transfer load from the Sadadeen 11 kV switchboard to Lovegrove under N and N-1 scenarios. However, once RGPS is retired there will be a shortfall in capacity of approximately 8.5 MVA under a N-2 scenario. This is due to the capacity of the 22/11 kV transformers at Lovegrove zone substation and distribution network constraints.

On the 22 kV network, there is currently sufficient transfer capacity under N, N-1 and N-2 scenarios. However, the forecast load growth on the 22 kV network means there will be an increasing shortfall of supply capacity in the future.

More information on the capacity required to address these shortfalls in transfer capacity is provided in section 3.2.2.

3. Identified need

We have assessed the Sadadeen 22 kV switchboard to be at end of life based on the condition of the asset and history of failures. The deteriorated condition of this asset presents a risk to the reliable and secure operation of a significant part of the Alice Springs distribution network.

3.1 Deteriorated asset condition

The Sadadeen 22 kV switchboard is a 33-year-old indoor switchboard with SF6 insulation that consists of 2 buses. It has two 22 kV feeders from Lovegrove zone substation, supplies 3 feeders at 22 kV (Jay Creek feeder is not in service) and three 22/11 kV transformers. There is one generator, Set 9 from RGPS, connected. The single line diagram is shown in Figure 4.

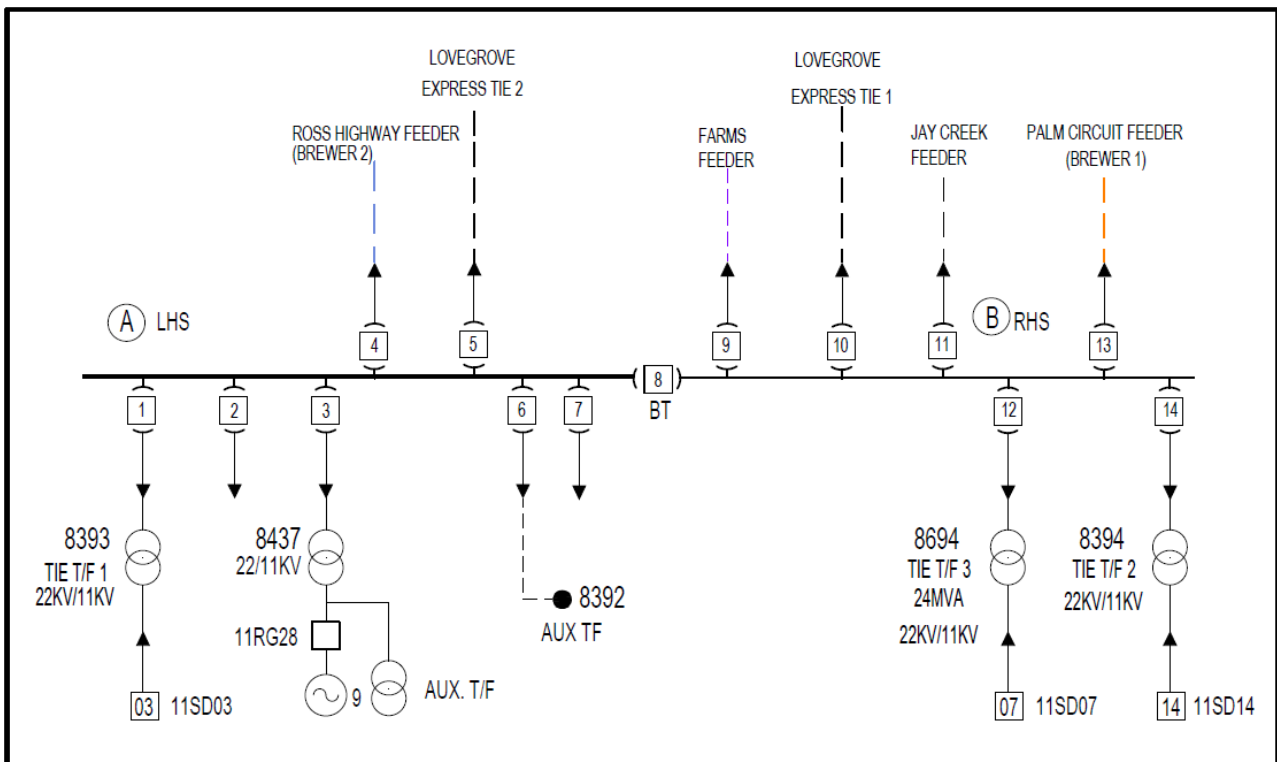


Figure 4: Single line diagram for the Sadadeen 22 kV switchboard

There are multiple issues identified on the switchboard that result in both network reliability and health and safety hazards:

Partial discharge

- The switchboard is a Yorkshire YSF6 type exhibiting significant partial discharge across various parts of the board and circuit breaker trucks. The partial discharge issue on this make and model of switchboard has been observed across the electricity industry. The issue is attributed to the switchboard design resulting in significant electrical stress on specific parts, exacerbated by high humidity. Even when reduced through environmental controls, the low levels of partial discharge continue to deteriorate the insulation and increases the probability of a fault and asset failure when environmental conditions change, even for very brief periods. The result is a considerable reduction in serviceable life of the switchboard compared to industry expectations.

- The partial discharge is highest on the right-hand side (Bus B), which is also the most critical bus as it supplies 2 transformers for the 11 kV network and 3 feeders to the 22 kV network.
- In 2022, the Sadadeen switchboard was fitted with an online partial discharge monitoring system that provides data for analysis. We commissioned EA Technologies⁸ to undertake analysis of the data recorded. The analysis found 5 instances of partial discharge recorded that were severe enough to require inspection and further investigation:
 - Multiple transient events between 15 July 2022 and 23 March 2023 on the 22RG01 transformer 1 coupling and cable box.
 - Ongoing partial discharge identified on the spare circuit breaker 22RG02.
 - Ongoing partial discharge was recorded on the spare circuit breaker 22RG07.
 - Ongoing partial discharge identified on the bus tie and bus bars on 22RG 08.
 - Ongoing events recorded on 22RG12 transformer 3 coupling and cable box.

Partial discharge should not occur within air insulated areas of a switchboard and is a lead indicator of asset deterioration. Any partial discharge is detrimental to the insulation system and over time will eventually lead to failure.

This switchboard is susceptible to high levels of partial discharge, which increases the probability of in-service failure.

- There are also water ingress issues with the building that creates a high humidity environment within the switch room. The level of partial discharge has been observed to increase as humidity increases. The switchboard is reliant on the continued operation of large commercial dehumidifiers to maintain low humidity levels.

Asset failures

- This type of switchgear has a history of poor performance across our networks and other electricity businesses causing a high number of failures or near misses⁹. Inspection of the failures found the cause to be flashovers, with evidence of partial discharge demonstrating the deterioration of the insulation over time, supporting the identified issue at Sadadeen.
- On our networks, there have been 3 failures and 2 near misses in recent years on the YSF6 type switchboards. We note the removal and decommissioning of the Katherine and Manton switchboards in 2012 and 2013 respectively. The failures and near misses were:
 - 2005 – A partial discharge was detected at Katherine zone substation. Inspection found a number of components had disintegrated due to prolonged partial discharge. Identification occurred before a failure.
 - 2008 – The cause of a failure at Manton zone substation was found to be a flashover from the bus bar to the metal frame, with evidence of partial discharge tracking at the flashover location.
 - 2008 – Following the failure at Manton zone substation, Sadadeen was inspected with extensive damage due to partial discharge identified. These issues were identified before a failure.
 - 2009 - Katherine zone substation failure caused by flashover where the circuit breaker connected to the bus. Issues with partial discharge were ongoing until the asset was retired.

⁸ EA Technologies are an internationally recognised service provider specialising in partial discharge detection and analysis on electrical equipment.

⁹ Where inspection has found significant deterioration of the asset that would have resulted in a failure if not found.

- 2010 - A bus section failed at Sadadeen zone substation due to deteriorated internal components. The fault resulted in flashover between SD07 and SD08 and demonstrates the reduced level of insulation. High humidity in the switch room contributed to the failure.

Obsolete technology

- This is the last switchboard of its make and model on the network. Switchboards were replaced at Katherine and Manton in 2008 and 2010, respectively. They were considered at end-of-life due to significant deterioration of insulation condition leading to multiple failures that also caused additional damage and contamination. The Sadadeen switchboard was retained as it is in a lower humidity environment. By using environmental controls and restricting access to limit exposure to the hazards produced by high voltage insulation failures, asset life could be extended.
- The decommissioned switchboards provided spare parts for minor failures in Sadadeen and are now exhausted. The spare circuit breakers have been in storage for more than 10 years and require refurbishment prior to being put into service. Some common components are readily available, however most of the major components need manufacturing on request, if they are available. The refurbishment of circuit breakers and manufacture of components has a lead time from 90 to 180 days and is expensive due to individual manufacture rather than part of a large batch. Hence, any fault is likely to result in the network being at a reduced level of security for an extended period, with elevated potential for significant disruption to customers and increased risk of subsequent failures.
- Distribution feeder protection assets are also at end-of-life. These assets are showing signs of deterioration, use obsolete technology (first generation digital SPAJ relays) and have limited and insufficient functionality. They are 30 years old and require replacement by 2027. Mounted in the switchboard and directly adjacent, extensive work on and around the board increases exposure for workers without de-energising the board for upgrade and does not address access risks for ongoing maintenance.

Safety limitations

- The switchboard is not arc-fault rated; therefore a failure poses a health and safety risk to field crews. Failure is most likely to occur during switching operations that requires the presence of field crews, increasing the safety risk.

The switchboard is only equipped with frame leakage protection rather than high speed differential protection, which operates more slowly than high speed differential protection and is tested less frequently as it can only be tested with the entire bus out of service. This increases the risk of an arc flash resulting in failure of the switchboard.

The current condition of the switchboard is considered poor and at the end of its serviceable life. This is supported by:

- the extent of partial discharge being observed throughout the board via the online monitoring system
- deterioration of the insulation caused by historical partial discharge events that has also been observed during visual inspections and offline partial discharge testing.

Our view that the Sadadeen switchboard has reached end-of-life is further supported by the historical failures, all of which demonstrated partial discharge damage at the faulted location that reduced insulation integrity, leading to flashovers. The partial discharge is therefore considered a leading indicator of asset failure.

Management of these risks is operational through the deployment of dehumidifiers, permanent partial discharge monitoring for analysis, and operational restrictions to manage the health and safety of field crews.

3.2 Consequence of asset failure

As described in section 3.1, the switchboard condition is significantly deteriorated with a history of failures. Bus or switchboard failure are assessed as credible scenarios.

The 3 key risks/consequences needing addressing by any credible network or non-network option are as follows.

3.2.1 Health and safety

Arc faults are a significant risk to the safety of field crews. Insulation deterioration can cause asset failure by electricity arcing across from an active phase to earth or between phases. This arc releases a significant amount of energy that generates heat and causes gases to expand. The longer the arc is sustained, the more energy is released, which can result in an explosion and serious injury of anyone nearby. High speed differential protection is fast acting and isolates the asset, however frame leakage protection detects current in the earthing system and is much slower, allowing more energy to be released, increasing the risk of an explosion.

As stated in section 3.1, the switchboard is not rated to contain an arc fault with only frame leakage protection, increasing the chance of an explosion. The inherent design of this switchboard, likely failure modes and deteriorated condition poses an elevated risk to field crews.

Switchboard faults are more likely to occur when switching is undertaken, which means it is more likely for a field crew to be present at the time of the fault.

Current risk management is through operational restrictions that require remote switching. The field crew must be present to physically rack in the circuit breakers. Remote switching mitigates the safety risk to our employees - it does not fully alleviate it.

3.2.2 Loss of supply to customers

As described in section 3.1, the switchboard is in significantly deteriorated condition. Failure of a single bus or the entire switchboard are assessed to be credible scenarios. In addition, due to the lack of available spare components, return to service of the switchboard following a failure is not certain, leaving the network in a state of reduced security, increasing the consequence of a subsequent failure.

We assessed the impact of a failure to determine the load at risk and to present it in a way that enables assessment of whether network and/or non-network options will manage the consequence. In this assessment, we noted where there would be outages during switching to restore supply and excluded that from our assessment of any sustained capacity constraints.

Figure 5 shows a 90% Probability of Exceedance, Average and a 10% Probability of Exceedance for the daily demand for each 30-minute period of the day on the 11 kV network for the financial year July 2020 to June 2021. It also shows the profile of the day during the 2020-21 year with the maximum demand, illustrating the maximum shortfall that could occur. The network capacity under N, N-1 and N-2 scenarios are shown for comparison.

The network demand is consistently higher during the October to March period. This is the time when humidity is highest, which elevates the probability and consequence of a fault. The elevated consequence of failure is included in our modelling.

Figure 6 shows the Load Duration Curve (LDC), which shows the percentage of the year that each level of demand is exceeded. For example, 25MVA demand is exceeded for 12% of the year, or approximately 1,050 hours.

Under an N-2 scenario, once Ron Goodin is retired, there is an expected supply constraint due to the capacity of transformers at Lovegrove zone substation.

Based on the annual LDC shown in Figure 6, there would be a short fall across a year of 212 MWh over a duration of 114 hours with a peak demand of 8.5 MW. The worst case, based on maximum demand, could result in the inability to supply 32.6 MWh with a peak of 8.5 MW, average of 4.1 MW for a duration of 8 hours. In a year, there are 36 days when there would be a capacity shortfall. These parameters describe the capacity and performance required from any solution to address the need.

We note a short-term outage is expected for some customers while network switching is undertaken. This is excluded from consideration of the sustained outage.

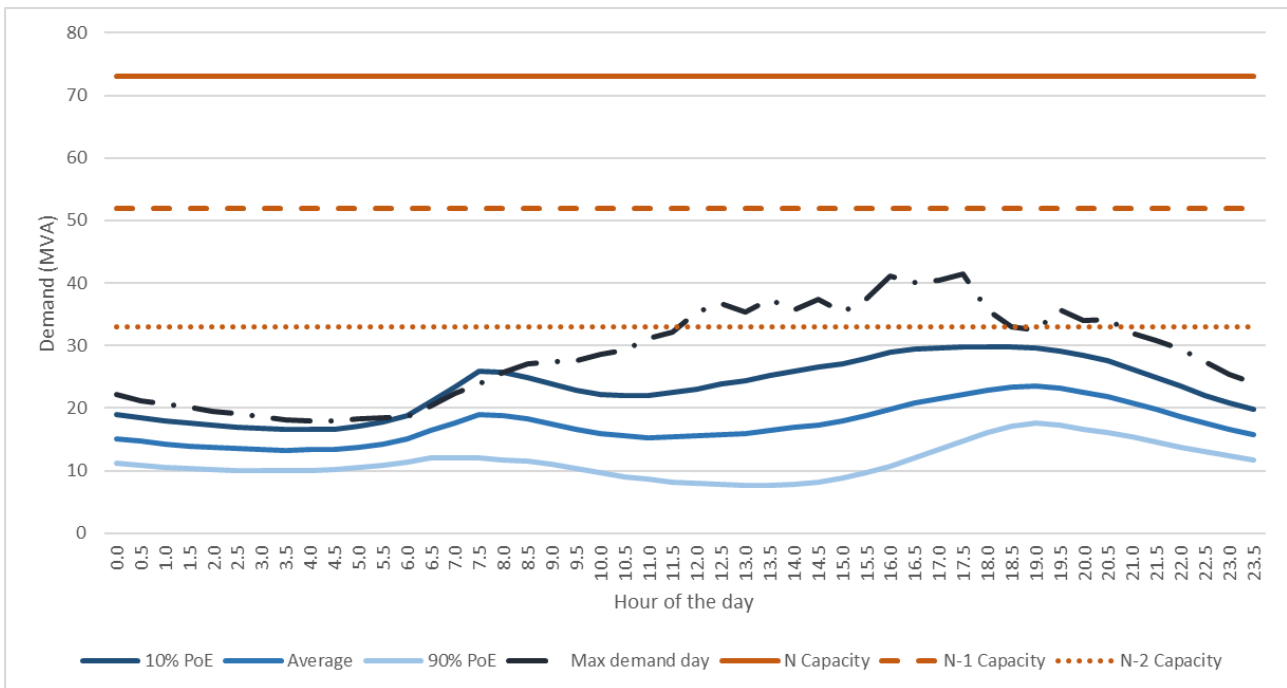


Figure 5: 11kV network daily load profile compared to network capacity under credible scenarios

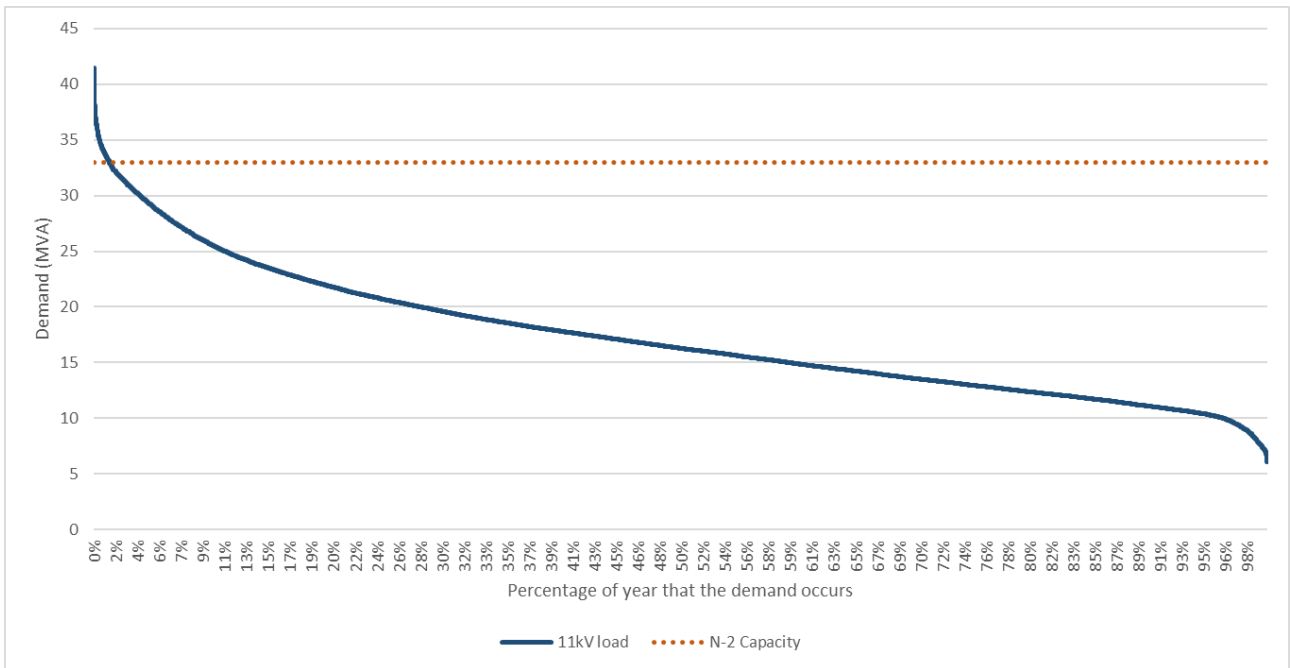


Figure 6: Load duration curve of the 11 kV network compared to the N-2 capacity

Figure 7 shows the minimum, average and maximum daily demand for each 30-minute period on the 22kV network for the financial year July 2020 to June 2021. The network capacity under N, N-1 and N-2 scenarios is shown for comparison.

It demonstrates that under N, N-1 and N-2 scenarios the Brewer Transformer, excluding any short-term interruptions that may be required to enable network switching to restore supply and current high voltage issues, can currently supply the load on the 22 kV network.

Demand on the 22 kV network is currently 8.1 MVA and is within the Brewer Transformer capacity. Therefore, no shortfall in supply is expected under any outage scenarios. However, demand forecast for the 22 kV network shows increasing demand, with the majority of future growth in Alice Springs planned for south of The Gap. Therefore, the load at risk is expected to increase over time introducing an additional constraint to be addressed by any proposed solution.

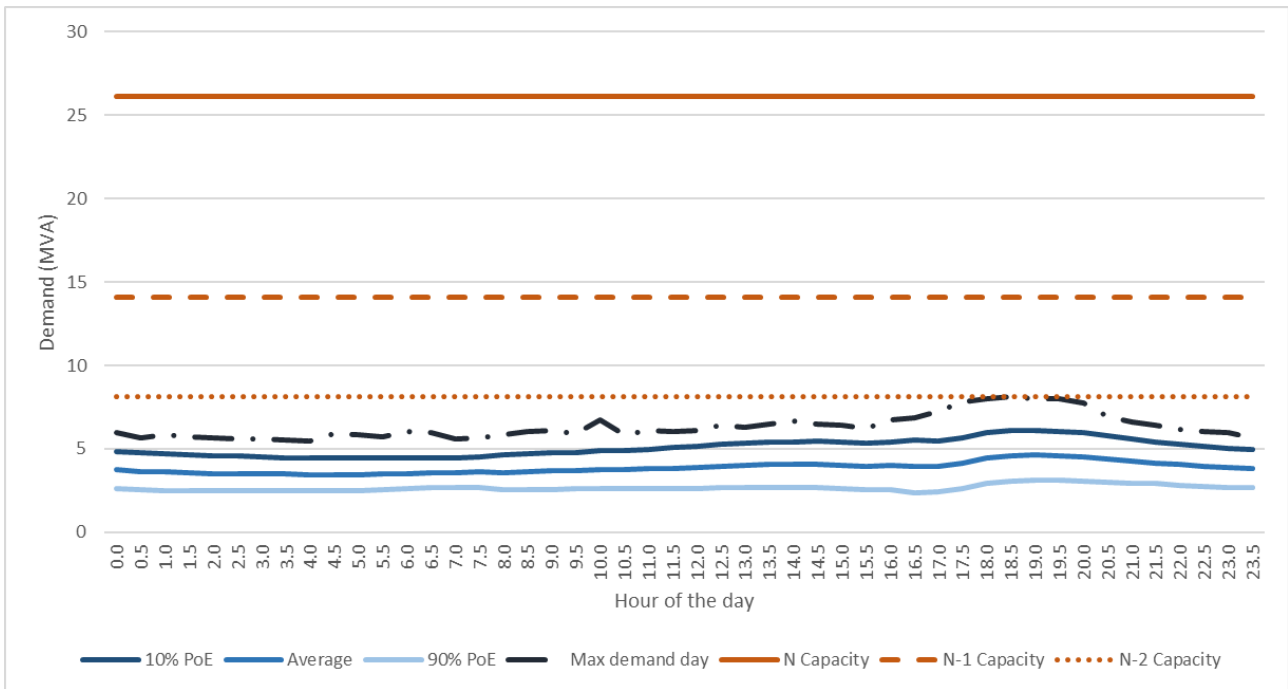


Figure 7: 22 kV network daily load profile compared to network capacity under credible scenarios

Note: Uterne solar power station provides approximately 2 MVA to the 22 kV network and is excluded from Figure 7.

Table 1 summarises the impact to be managed on each network based on the current demand data. The value of lost load calculated is based on the most recent Value of Customer Reliability (VCR) of \$20.37 per kWh published by the AER for residential customers in the Northern Territory.¹⁰

Scenario	Peak demand	Duration	Energy	Value of lost load
Max daily profile	8.5 MW	8 hrs	33 MWh	\$0.67 million
Annual shortfall	8.5 MW	114 hrs	212 MWh	\$4.32 million

Table 1: Summary of impact on supply capacity for the 11 kV network

3.2.3 Loss of network security and system black events

Failure of the entire Sadadeen switchboard would result in the sudden loss of a significant amount of load and impact the operation of generators. There is a high risk that the generators would not ride through the fault. The likely outcome a system black event where power is lost to the entire Alice Springs power system by disconnection of the generators from the network to protect them and network equipment from damage.

The sequence of events and technical reasons that could lead to a system black under different network loading configurations are described in Table 2.

¹⁰ Australian Energy Regulator, 2022 VCR Annual Adjustment, December 2022

We note that system black events have occurred in Alice Springs in the past:

- Most recently in 2019 due to a sudden reduction in generation from a solar generator.
- In 2012 and 2017 due to limitations on the operating state of the generators. After a significant network fault, the network and generation protection devices operated to shed load and avoid damage to the generators, network and customer assets.

Due to its configuration, restarting the Alice Springs network can be a time-consuming process with some specific technical issues needing to be managed. This results in an extended outage for our customers.

While the capability to ride through disruptions and restore the network has improved since the 2019 system black, it demonstrates the susceptibility of the network to significant unexpected disruptions as well as reduced network security and system black potential to be credible outcomes.

Due to the unavailability of spare parts, switchboard repair and return to service following a failure is uncertain. If one bus fails, the network would be in a reduced level of security and with a single point of failure for an extended period. This increases the risk of a subsequent fault occurring and a system black.

Network load scenario	Assessment of system black risk
<p>Low load (at or below 13 MW)</p>	<ul style="list-style-type: none"> - 20% to 50% chance of system black. The lower the load, the higher the risk. Our economic modelling assumed a base case of 35% as the midpoint of the estimate. Sensitivity and scenario analysis will test the impact of the upper and lower limits. - At low load, the machines operating at the lower edge of their capability, likely with only 4 units running. With loss of between 30% and 48% of the system load depending on the time of day and year, all machines will need to reduce active power to below minimum operational point. This is likely to result in one of the machines to trip off on reverse power. - One unit tripping can then cascade to other machines and cause them to trip off due to under excitation limiters, over frequency or over voltage. - At load below minimum operational point, generators are also likely to trip off due to mechanical issues such as vibration, as they are not designed to operate at such low levels for prolonged periods.
<p>Average load (13 MVA to 27 MVA)</p>	<ul style="list-style-type: none"> - 15% chance of system black. Our economic modelling assumed a probability of 15% as the base case. Sensitivity and scenario analysis will test the impact of changing this assumption. - The cause of a system black is the same as for low load, however since there is higher load on the network there is more time/ability for the generator governors to react in time to correct the issues.

Network load scenario	Assessment of system black risk
High load (>27 MVA)	<ul style="list-style-type: none"> - 20% to 30% chance of system black. The higher the load, the higher the risk. Our economic modelling assumed a base case of 25% as the midpoint of the estimate. Sensitivity and scenario analysis will test the impact of the upper and lower limits. - The absolute MW of load lost is significant. This will result in an increase in network frequency. The higher the load (and larger the amount lost) the more rapid the rise in frequency. Over frequency protection on the generators is likely to trip more than one machine. - This can then result in under frequency if too much generation is removed from the network and the under-frequency load shedding scheme will operate to remove load to raise frequency. - Due to the size of MW involved, there is not enough time for machine governors to react to the change between over frequency and under frequency, which will lead to load or generation shedding and system black. - This is what occurred in 2017, demonstrating it is a credible scenario.

Table 2: Summary of system black risk based on network load

4. Description of credible options

This section describes the various options analysed to address the increasing risk and identify the recommended option. The options were analysed based on ability to address the identified needs, prudence and efficiency, commercial and technical feasibility, deliverability, benefits and an optimal balance between long term asset risk and short-term performance.

4.1 Network options

Table 3 provides details of credible options identified as part of network planning activities to date. All costs in this section are in real \$2022/23, unless otherwise stated.

Option overview	Concerns	Estimated capital cost
<p>1. Do nothing: continue to manage the asset operationally.</p>	Accepts the increasing risk.	\$0
<p>2. Replace with a modern equivalent switchboard: direct replacement to the current asset to maintain the same network configuration:</p> <ul style="list-style-type: none"> Construct new switch room or repair existing switch room Install new 22 kV switchboard Install new protection, SCADA, communications and auxiliary secondary systems Decommission existing assets. 	This option has a high capital cost and is likely to create a stranded asset once RGPS is retired.	\$10.3 million
<p>3. Replace with a temporary mobile switchboard: direct replacement with a temporary solution to defer larger expenditure:</p> <ul style="list-style-type: none"> Repair the mobile switchboard Upgrade protection, SCADA, communications, and auxiliary secondary systems Transport to site and install Cut over cables from the existing switchboard Decommission existing switchboard. 	<p>The temporary switchboard consists of only one bus, therefore this option would introduce a single point of failure on the network and will not meet the objectives of maintaining network reliability and security.</p> <p>While undertaking the options analysis, the temporary switchboard was allocated to another project. Initial analysis suggests the switchboard will be required for the alternative project for some time and is therefore unlikely to be available to support the retirement of the Sadadeen 22 kV switchboard.</p> <p>This means there is a significant risk that the proposed solution may not be a credible option. Nevertheless, we have still included the option in our cost benefit analysis.</p>	\$5.3 million

Option overview	Concerns	Estimated capital cost
<p>4. Retire the switchboard – 2 cable solution: install 2 new 22 kV cables to enable the switchboard to be bypassed and retired:</p> <ul style="list-style-type: none"> • Install 2 cables from the Lovegrove 22 kV switchboard to connect to the existing ‘Farms’ feeder • Connect the Sadadeen end of the Farms feeder to the Brewer ties (via GCB) • Connect 22 kV express feeders to 22/11 kV transformers • Decommission switchboard and RGPS Set 9. 	<p>This is the preferred option. Refer below.</p>	<p>\$7.4 million</p>
<p>5. Retire the switchboard – 11 kV express ties and 11/22 kV substation at Owen Springs: augment the existing 22 kV switchyard at Owen Springs to supply all the 22 kV network and retire the Sadadeen 22 kV assets:</p> <ul style="list-style-type: none"> • Establish a new zone substation at the Owen Springs/Brewer site. Install 2 new 22/11 kV transformers and associated assets to replace the unit transformer • Upgrade the connection from OSPS to the new transformers • Connect 22kV express feeders to 22/11kV transformers • Decommission switchboard and RGPS Set 9. 	<p>This option is expected to be expensive.</p> <p>Feasibility of supply of sufficient capacity from OSPS to a new 11/22 kV switchyard is not confirmed.</p>	<p>\$17.7 million</p>

Table 3 Summary of credible network options

4.2 Non-network options

Due to the type and function of these assets, there are no non-network alternatives or solutions that can be implemented to resolve all aspects of the identified network issue. A range of potential non-network options were assessed including additional generation, Battery Energy Storage System, demand management and SAPs. We note that the Regulatory Investment Test for Distribution (RIT-D) guidelines¹¹ clarify that an option is not considered credible if any one of the assessment criteria is not met.

¹¹ Australian Energy Regulator, Application Guidelines for the Regulatory Investment Test for Distribution, August 2022, page 75

For the reasons set out in the Non-Network Options Notice¹², pursuant to clause 5.17.4(c) of the NT NER, we have determined there are no credible non-network options to address the identified need at Sadadeen zone substation.

4.3 Network options considered but rejected

Our analysis identified an alternative option, however, it was found to be non-credible based on time to implement and cost, and is described below.

Retire the switchboard – 11 kV express ties and 66/22 kV substation at Norris Belle

Build a new 66/22 kV zone substation at the Norris Belle site to supply all the 22 kV network and decommission the existing 22kV switchyard at Owen Springs and retire the Sadadeen 22 kV assets. The forecast demand is not enough to trigger the need for this scale of investment as the expected cost to construct a new zone substation and the related sub transmission works is more than \$40 million. It would not be deliverable within the timeframe required to address the identified need.

5. Economic assessment of options

In this section we present the results of economic assessment of the business-as-usual approach to managing this asset and 4 credible options, set out in table 4.1. The scenario analysis identifies the preferred option, which is subject to sensitivity analysis and optimum timing analysis.

The preferred option will maximise the net economic benefit to customers and meet the identified need of enabling continuity of reliable supply to our customers, as set out in section 3.

5.1 Methodology

The methodology applied in this assessment aligns with the requirements of the NT NER and the approach set out by the AER:

- Application guidelines - Regulatory investment test for distribution - December 2018
- Industry practice application note - replacement planning - January 2019.

Our methodology calculates the annual Sadadeen switchboard risk cost, based on the probability of failure of the asset under different failure modes, the likelihood of consequences of the failure and the severity of that consequence.

When assessing the base case, the risk assessment is limited to the key failure mode of bus failure and its consequences. The failure modes modelled consider:

- failure of the bus insulation, demonstrated to be in deteriorated condition
- failure of the circuit breaker coupling (connection point) to the bus that will result in a bus outage. There is evidence of deterioration of these connection points – with failure previously experienced on other YSF6 switchboards on our networks.

¹² TRIM reference D2023/251913

The costs for each failure mode were estimated in each of the following consequence areas:

- Involuntary supply interruption:
 - Short term impact while switching is undertaken to restore supply immediately following a bus fault
 - Long term impact due to inability to repair the bus fault resulting in a long-term capacity shortfall.
- Impact to network security (system black event)
- Safety (i.e. threat to our workers, the public are not able to access the asset so were not included)
- Operating expenditure (the difference between a new and old asset)
- Capital expenditure associated with restoring supply following asset failure.

The cost, timing and degree of risk mitigation of each option is assessed to determine the economic impact of the option and any benefit it provides compared to the base case. The option with the highest economic benefit is the preferred option.

The consequence of an individual circuit breaker failing that does not affect the bus is not expected to be material and is unlikely to change the ranking of the options assessment. Therefore, we have taken a conservative approach and excluded this scenario from the analysis.

5.2 Key variables and assumptions

Table 4 lists the variable tested in the scenario and sensitivity analysis, the type of variable and a description of its impact on the model.

Variable	Type / Category	Description
Discount rate	Financial	The Weighted Average Cost of Capital (WACC) discounts the future value of money. The higher the WACC, the lower the value of future revenue/cost in present terms.
Capex	Financial	A factor to adjust the capital cost of the proposed option.
Opex	Financial	A factor to adjust the ongoing operational cost of the proposed option.
RGPS capacity	Capacity	The availability and reliability weighted dispatchable capacity available from RGPS.
RGPS retirement year	Capacity	Expected year that RGPS will close.
Demand forecast (PoE)	Demand	Forecast network demand based on the most recent 10 year forecast.
Demand growth rate – 11 kV	Demand	Rate of demand growth on the 11 kV network applied to the period beyond the demand forecast.
Demand growth rate – 22 kV	Demand	Rate of demand growth on the 22 kV network applied to the period beyond the demand forecast.
VCR sensitivity	Consequence / Risk	A factor to adjust the Value of Customer Reliability (\$/kWh) published annually by the AER and is weighted by customer type numbers. The factor accounts for future changes in the published value of the VCR.
Characteristic life	Probability of failure	Expected life of the asset. An input to the survival curve based on a Weibull probability distribution.
Shape factor	Probability of failure	An input to the survival curve based on a Weibull probability distribution. This factor defines the shape of the survival curve for a given characteristic age.
Probability of system black	Consequence / Risk	Probability that an outage will result in a system black event.
Duration of system black	Consequence / Risk	Duration to restart the electricity network following system black.
Repairability	Consequence / Risk	Probability that a fault can be repaired, accounting for the extent of damage and availability of parts. If not repairable (1 – Repairability) then capital replacement solution is required, increasing the risk-cost.
Probability of a safety incident	Consequence / Risk	Likelihood that an asset failure will result in injury to an employee.

Table 4: Variables used in the scenario and sensitivity analysis

Table 5 sets out the values applied to each variable for the purposes of the scenario analysis. The values have been determined based on our expectations and experience.

Variable	Lower bound	Expected	Upper bound
Discount rate	4%	6%	8%
Capex	-10%	0%	+20%
Opex	-10%	0%	+10%
RGPS capacity	0 MVA	5 MVA	15 MVA
RGPS retirement year	2024	2026	2030
Demand forecast (PoE)	PoE 90	PoE 50	PoE 10
Demand growth rate – 11 kV	-3.0%	-1.0%	1.0%
Demand growth rate – 22 kV	0.0%	2.0%	4.0%
VCR sensitivity	-5%	0%	5%
Characteristic life (years)	35	40	45
Shape factor	5	5	5
Probability of system black	19%	30%	41%
Duration of system black (hours)	4	6	12
Repairability	80%	90%	95%
Probability of a safety incident	0.0%	2.5%	5.0%

Table 5: Values applied to the variables for the scenario analysis

We note that negative growth in demand and VCR is intended to reflect a future state where solar PV and storage has expanded, which reduces future demand growth and the reliance on the grid, reducing the VCR.

5.3 Scenarios adopted for option assessment

Five scenarios that depict possible future states of the world were developed using the key variables listed in Table 4. These scenarios are described in Table 6 along with the weighting applied to the outcome of each. The sum of the weighted Net Present Values (NPVs) of each scenario is used to identify the option that is preferred, as it will most likely maximise benefits to customers under most future circumstances.

#	Scenario	Description	Weighting (%)
1	Expected case	The expected future state of the world with all variables taking on the expected value.	40%
2	Low growth, low risk	The most benign conditions where the risk is expected to be minimal. Low demand and low demand growth expectations, low consequence/risk parameters, high financial parameters (higher cost of capital up front and reduced value of future risk through discounting).	20%
3	High growth, high risk	The worst-case conditions where the risk is expected to be highest. High demand and high demand growth expectations, high consequence/risk parameters, low financial parameters (lower cost of capital up front and increase value of future risk through less discounting).	10%
4	Low growth, high risk	This represents where demand growth is low, however, the risk is high with a lower WACC, lower availability of RGPS, but increased risk of system black and lower chance of repair of the asset.	20%
5	High growth, low risk	This represents where demand growth is high, however, the risk is low with a higher WACC to reduce the present value of future risk, higher availability of RGPS, with reduced risk of system black and higher chance of repair of the asset.	10%

Table 6: Description of scenarios

Note that due to growth in solar PV in Alice Springs, we expect a low network demand scenario will be more likely than a high network demand growth scenario.

To construct these scenarios, Table 7 sets out the value of each parameter that is applied in each of the scenarios based on the lower, expected or upper bounds set out in Table 5.

Variable	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5
Discount rate	Expected	Upper	Lower	Lower	Upper
Capex	Expected	Lower	Upper	Upper	Lower
Opex	Expected	Lower	Upper	Upper	Lower
RGPS capacity	Expected	Upper	Lower	Lower	Upper
RGPS retirement year	Expected	Upper	Lower	Lower	Upper
Demand forecast (PoE)	Expected	Lower	Upper	Lower	Upper
Demand growth rate – 11 kV	Expected	Lower	Upper	Lower	Upper
Demand growth rate – 22 kV	Expected	Lower	Upper	Lower	Upper
VCR sensitivity	Expected	Lower	Upper	Upper	Lower
Characteristic life	Expected	Upper	Lower	Lower	Upper
Shape factor	Expected	Upper	Lower	Lower	Upper
Probability of system black	Expected	Lower	Upper	Upper	Lower
Duration of system black	Expected	Lower	Upper	Upper	Lower
Repairability	Expected	Upper	Lower	Lower	Upper
Probability of a safety incident	Expected	Lower	Upper	Upper	Lower

Table 7: Values of each variable applied to construct each scenario

5.4 Sensitivity analysis

In analysing sensitivity, we change each individual input using the upper and lower bound in Table 5 to assess the impact of each individual input on the outcomes of the economic modelling. This differs from scenario analysis, which changes multiple variables at the same time.

The purpose of sensitivity analysis is to identify if the model is sensitive to any individual inputs and informs us of any factors that need careful control when implementing the preferred solution.

5.5 Cost benefit analysis results

Option 4 has the best cost benefit analysis outcome in all scenarios assessed as it enables risk mitigation at low capital cost.

5.5.1 Economic analysis outcomes

The outcomes of economic analysis of the credible options are shown below for Net Present Cost (NPC), Net Present Value (NPV) and Benefit Cost Ratio (BCR). It demonstrates that under all scenarios and the weighted total, Option 4 has the lowest cost/highest benefit to our customers.

Table 8 shows outcomes of the scenario analysis as Net Present Cost (NPC), the sum of the capital expenditure, operational expenditure and risk cost discounted into FY24 dollars. The option with the lowest NPC is preferred as it represents the lowest cost to our customers.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Weighted total	Rank
Option 1	\$119,268	\$12,161	\$1,767,865	\$376,776	\$135,148	\$391,500	5
Option 2	\$14,392	\$9,311	\$66,907	\$23,874	\$12,945	\$22,712	3
Option 3	\$17,860	\$6,427	\$311,049	\$49,673	\$45,855	\$69,094	4
Option 4	\$7,899	\$6,761	\$12,227	\$11,362	\$6,770	\$8,728	1
Option 5	\$19,061	\$15,276	\$31,838	\$29,087	\$15,625	\$21,398	2

Table 8: Scenario analysis outcomes as Net Present Cost (\$'000, FY24)

Table 9 shows outcomes of the scenario analysis as NPV, the sum of the discounted avoided risk cost (benefit of the option), capital expenditure and operational expenditure into FY24 dollars. In this case, Option 1 is the base case (reference case) other options are measured against. The option with the highest NPV is preferred as it represents the highest benefit to our customers.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Weighted total	Rank
Option 1	\$-	\$-	\$-	\$-	\$-	\$-	5
Option 2	\$104,876	\$2,849	\$1,700,958	\$352,902	\$122,203	\$368,787	3
Option 3	\$101,409	\$5,734	\$1,456,816	\$327,103	\$89,293	\$322,405	4
Option 4	\$111,369	\$5,400	\$1,755,638	\$365,414	\$128,379	\$382,772	1
Option 5	\$100,207	-\$3,115	\$1,736,026	\$347,689	\$119,523	\$370,101	2

Table 9: Scenario analysis outcomes as Net Present Value (\$'000, FY24)

Table 10 shows outcomes of the scenario analysis as Benefit Cost Ratio (BCR), the sum of the discounted benefits (NPV) divided by the discounted costs (NPC). A BCR greater than one means the benefits exceed the cost. The option with the highest BCR is preferred as it represents the highest benefit to our customers.

	Scenario 1	Scenario 2	Scenario 3	Scenario 4	Scenario 5	Weighted total	Rank
Option 1	0.0	0.0	0.0	0.0	0.0	0.0	5
Option 2	7.3	0.3	25.4	14.8	9.4	16.2	3
Option 3	5.7	0.9	4.7	6.6	1.9	4.7	4
Option 4	14.1	0.8	143.6	32.2	19.0	43.9	1
Option 5	5.3	-0.2	54.5	12.0	7.6	17.3	2

Table 10: Scenario analysis outcomes as Benefit Cost Ratio

5.5.2 Sensitivity and scenario analysis outcomes

We undertook sensitivity analysis for each of the options. Sensitivity analysis involved calculating the change in the project NPV based on the change of a single variable using the upper and lower bounds in Table 5.

Figure 8 shows the outcomes of the sensitivity as a tornado plot and demonstrates visually the magnitude of the impact of each variable on the outcome of the model. The analysis shows Demand Growth Rate on the 22 kV network, characteristic life, discount rate and repairability have the largest impact on the overall NPV of the project. Based on this analysis, we reviewed our assumptions and analysis regarding these parameters to ensure they are appropriate.

Under all sensitivities tested, we found the NPV of Option 4 remained positive and was the highest of the 5 options assessed. Even with a significant impact on the NPV of the project, none of the sensitivities affected the option found to be the most prudent and efficient. Therefore Option 4 remains the preferred option.

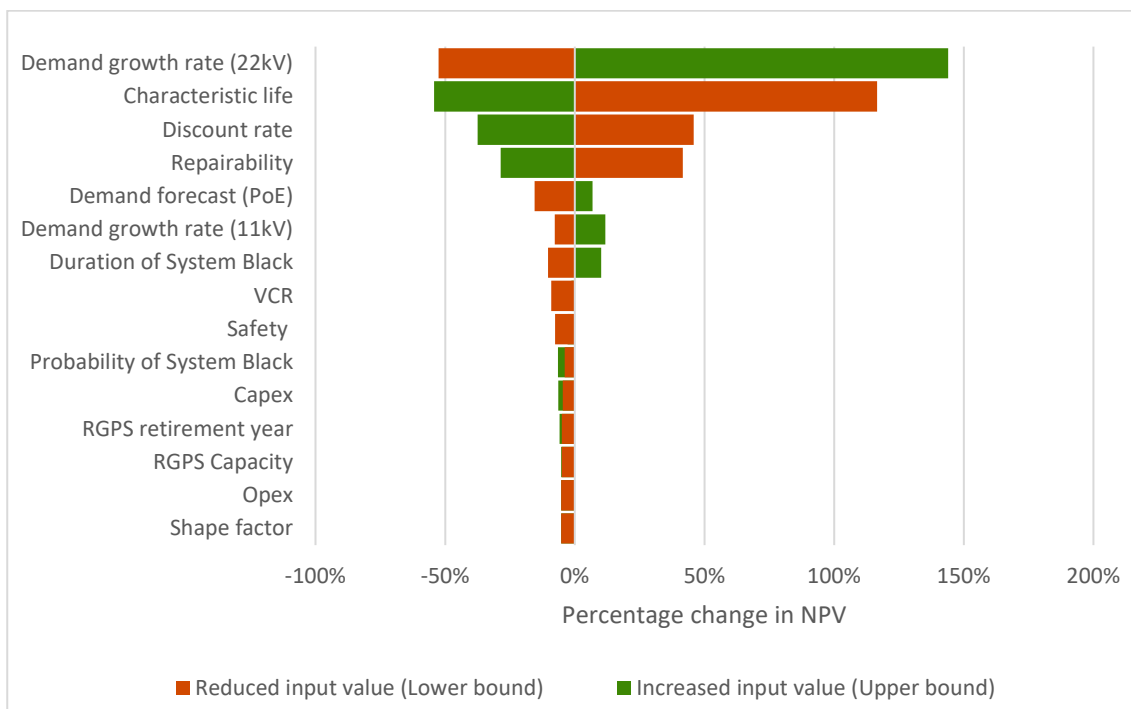


Figure 8: Tornado plot showing the percentage change in NPV based on changing an individual variable input

5.5.3 Optimum timing analysis

Optimal timing of implementation of the preferred option can be determined based on when the risk-cost of the base case exceeds the annualised cost of the preferred option, as described in the AER’s replacement planning guidelines¹³. We have undertaken this assessment for the preferred option under the 5 scenarios. Figure 9 shows the range of outcomes of the 5 scenarios versus the annualised cost of the preferred option. The grey shaded area is bounded by the upper and lower risk cost observed across the 5 scenarios.

As shown by the chart, the optimal time for replacement is no later than FY26 as the risk cost of the base case of retaining the switchboard exceeds the annualised cost of the preferred option. The inflection in the

¹³ Australian Energy Regulator, Industry practice application note – Asset replacement planning, January 2019, Section 4.6

expected risk from FY25 to FY26 is caused by the expectation of RGPS being closed in FY26, increasing the consequence of an outage.

The chart shows the optimal timing to have the preferred solution installed is as soon as possible and no later than FY26.

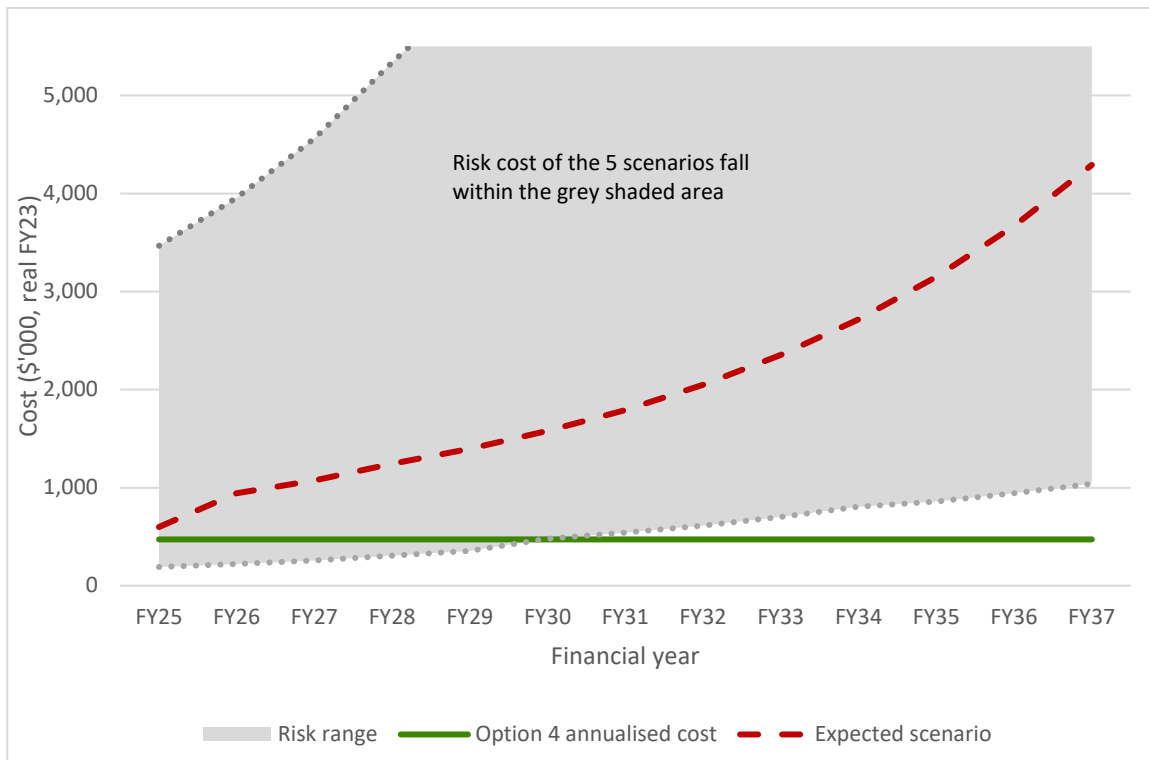


Figure 9: Annualised replacement versus base case risk-cost

6. Recommendation

Our recommendation is to implement Option 4 at an estimated cost of \$6.8 million (real FY24) with commissioning to be completed by the end of FY26.

The key points underpinning our recommendation are:

- There are no credible non-network options or SAPS¹⁴ options to address all or part of the identified need at Sadadeen (SD) zone substation. This determination was made under clause 5.17.4(c) of the National Electricity Rules, published pursuant to clause 5.17.4(d).
- In accordance with the provisions of the NT NER under clause 5.17.4(c) and 5.17.4(n), we have not published a non-network options screening report or a Draft Project Assessment Report in relation to the proposed works at Sadadeen zone substation.
- Assessment of 5 credible options based on the requirements set out in the RIT-D guidelines¹⁵ and the AER's asset replacement planning guidelines¹⁶.
- Analysis found that under all scenarios and in all sensitivities tested, Option 4 was preferred.
- Risk analysis found the optimal timing to implement the scope of work described under Option 4 has already passed indicating the project should be implemented as soon as possible.

¹⁴ We note that a recent rule change that requires the consideration of SAPS is not operational under the NT NER.

¹⁵ Australian Energy Regulator, Application Guidelines for the Regulatory Investment Test for Distribution, August 2022

¹⁶ Australian Energy Regulator, Industry practice application note – Asset replacement planning, January 2019

Appendix A. Satellite view of Alice Springs

Figure 10 provides a geographic satellite view of Alice Springs. It highlights the impact of The Gap on the connection between the northern and southern regions of the town. It also shows that most customers are north of The Gap.

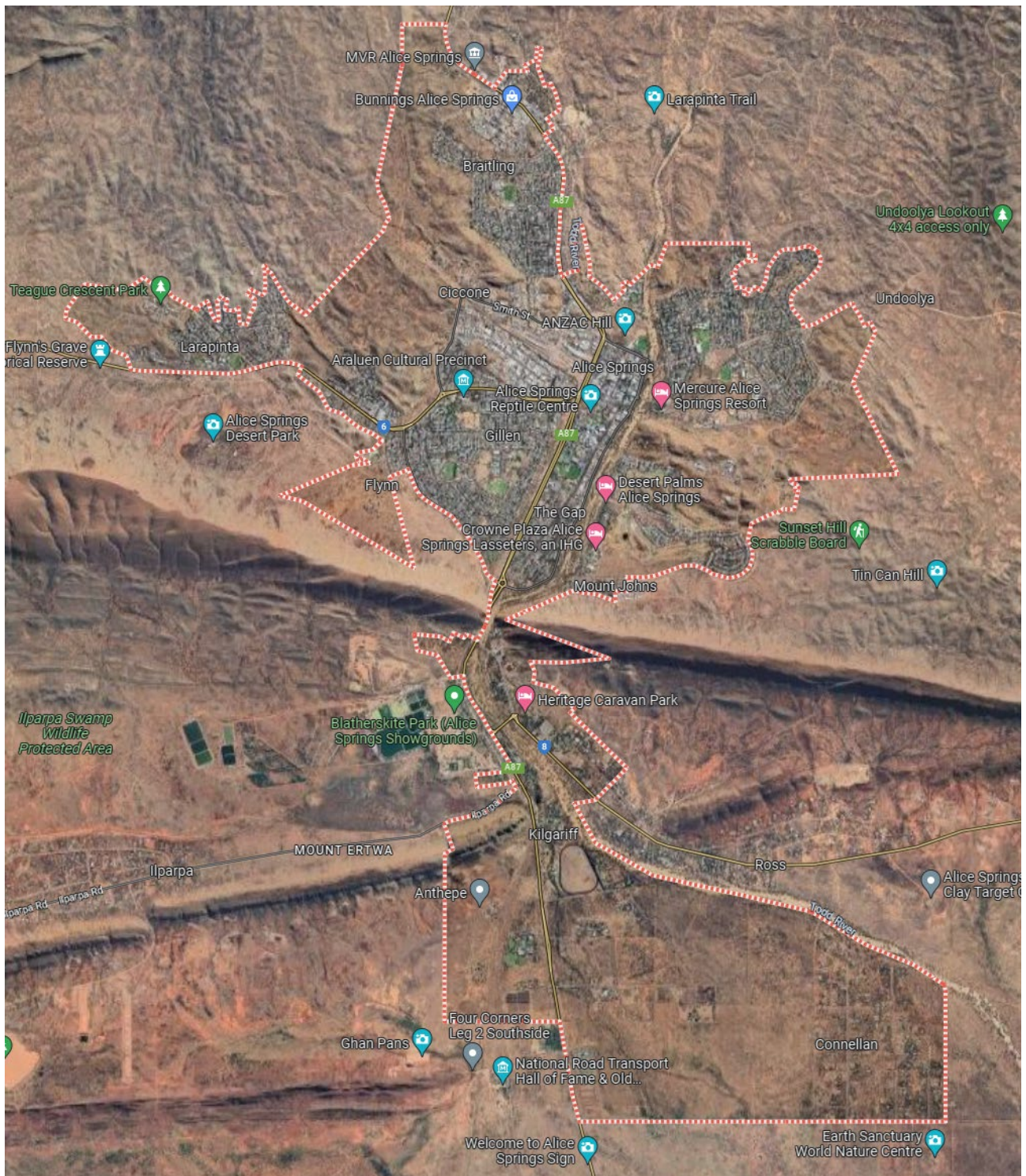


Figure 10: Satellite view of Alice Springs showing The Gap

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