Business case: Network Resilience Mobile Generation

2025-30 Regulatory Proposal

Supporting document [5.8.3]

January 2024

SA Power Networks

Empowering South Australia

Contents

Glossary

Acronym / term	Definition
ABC	Aerial bundled cable
AER	Australian Energy Regulator
Capex	Capital expenditure
kWh	Kilo-watt hour
HV	High voltage
MVA	Mega-volt amperes
MWh	Mega-watt hour
Opex	Operating expenditure
RCP	Regulatory Control Period
SAPS	Stand-alone power systems
VCR	Value of customer reliability
MED	Major event day
GSL	Guaranteed Service Level
STPIS	Service Target Performance Incentive Scheme
SAIDI	System average interruption duration index
SAIFI	System Average Interruption Frequency Index
CAB	Community Advisory Board

1 About this document

1.1 Purpose

This document provides a business case to support forecast expenditure for the 2025-30 Regulatory Control Period (**RCP**) on programs in the area of Network Resilience.

1.2 Expenditure category

This expenditure comprises one input to our overall network augmentation capital expenditure.

1.3 Related documents

This document should be read in conjunction with the following documents that specifically relate to these programs, and together form a suite of supporting documents to our Regulatory Proposal for this program:

- Network Resilience Forecasting Structure document - provides a structural overview of the approaches used to prepare the forecasts for the Network Resilience Mobile Generation program included in this business case.
- The Innovation Fund business case - a related business case to address network and community resilience issues where costs and benefits may be uncertain or difficult to quantify, and/or where addressing the need is best done in partnership with other stakeholders and the exact partnering models may be uncertain until closer to the date.

Ref	Title
1	5.8.4 - Network Resilience mobile generation forecasting Structure - Methodology
2	5.7.7 - Innovation Fund - Business case
3	5.3.1 - Network Asset Replacement Expenditure – Business Case
4	5.10.1 - Fleet Business Case
5	5.2.5 - Resourcing Plan for Delivering the Network Program

2 Executive summary

This program responds to the need to improve network resilience, especially during extreme weather events and in areas supplied by long, radial networks where customers are vulnerable to long duration outages. An investment of $7.1 million[1] over five years is proposed to procure three additional mobile generators with a combined capacity of 9MVA, which will return a Net Present Value of $11.6 million over 20 years. This investment is expected to increase our capability to use mobile generation to restore power to regional and remote communities when power restoration via repair of a radial network is delayed.

This recommendation is preferable to other options considered because:

- based on reasonable assumptions regarding the frequency of usage of these generators over their lives, the benefits to consumers by way of avoided unserved energy (measured using the Value of Customer Reliability, **VCR**) that result from this program exceed the costs;
- mobile generators are currently the most cost-effective mobile alternate power supply option where the cost of building an alternate supply line is prohibitive; and
- mobile generators provide greater reliability improvements when compared to fixed solutions, as they are able to be used more frequently due to their ability to relocate between fault affected areas.

This is a new area of expenditure that seeks to align to outcomes recommended by customers during our consumer and stakeholder engagement program.

[1] All financial figures are in June $2022 unless otherwise stated. Totals stated throughout document may not reconcile due to rounding.

3 Background

3.1 The scope of this business case

This business case responds to the need to improve the resilience of the distribution network and our electricity distribution services to customers from the impacts of extreme weather events and / or the occurrence of severe damage in areas of the network supplied by long radial lines. It considers options to reduce the duration of the interruptions to customer supplies that can result from these events.

It does not consider options to:

- replace assets where the need to replace is largely a function of the age / condition of the existing assets, which are considered in **supporting document 5.3.1 - Network Asset Replacement Expenditure – Business Case**;
- maintain existing mobile generation capability, which is considered in **supporting document 5.10.1 - Fleet Business Case** under a base-trend-step approach;
- enhance business-as-usual recurrent operating practices, which could relate directly or indirectly to network resilience (eg vegetation management, emergency response and major event management), which are forecast on a top-down basis using the Australian Energy Regulator's (**AERs**) base-trend-step approach; or
- apply innovative approaches to addressing network and community resilience issues where costs and benefits may be uncertain or difficult to quantify, and / or where addressing the need is best done in partnership with other stakeholders and the exact partnering models may be uncertain until closer to the date, which are included in **supporting document 5.7.7 - Innovation Fund - Business Case**.

The Network Resilience Mobile Generation program is a new program we are proposing to implement during the 2025-30 RCP.

3.2 Drivers for change

Overall drivers for change for network resilience

In engaging with our customers and stakeholders in developing our 2025-30 Regulatory Proposal, the importance of the impact of extreme weather-related events on electricity network performance, and the effect on communities, was evident. There is some uncertainty about the future impacts of climate change on the network which creates challenges for investing in adaptation and recovery to extreme weather.

SA Power Networks embeds network resilience concerns into planning and network operations through:

- a mature operational bushfire risk and emergency management approach;
- consideration of bushfire and reliability risks in augmentation and replacement expenditure planning; and
- the use of steel and concrete 'Stobie poles', which generally survive bushfires and floods, reducing ex-post repair costs and customer restoration times.

In developing the 2025-30 Regulatory Proposal, SA Power Networks undertook a high-level review and engagement with customers on hazards affecting the network which may increase in frequency and severity due to climate change, as shown in Figure 1.

It was also acknowledged that, while there is limited evidence on the impact of climate change on extreme wind and lightning storms in South Australia, these weather events already lead to significant impacts on customers, as evidenced by a storm event on 12 November 2022 when severe thunderstorms developed in the vicinity of Adelaide. Wind gusts of up to 106km/h were observed in the Adelaide area. Damage associated with vegetation and wind led to power outages impacting 160,000 customers (approximately 20 percent of SA Power Networks' customer base) and over 500 wires down jobs. In some areas of the Adelaide Hills, a full rebuild of parts of the network was required, with some customers off supply for a week.

Customer engagement also highlighted the vulnerability of regional and remote communities which are supplied by long, radial powerlines to widespread and long-duration outages due to weather events, asset failure and third-party impacts. With minimal alternative services nearby, these outages can lead to flow-on impacts to other community services, such as telecommunications, food and fuel.

Figure 1: Key weather factors of concern for South Australia

Heat

The number of hot days is increasing

No. of very hot days (>40 °C) increase from **2 to 6 days/year** in Adelaide between now and 2050, leading to potential:

- Increases in peak electricity demand
- Increased risk of network fire starts
- Increased health impacts of power outages, including from coincident storm or bushfire events[3]

Bushfire

Longer, riskier fire seasons

Longer fire seasons, with **~ 40%** more 'very high' fire danger days[1] between now and 2050, leading to potential:

- Increased risk of network fire starts
- Increased risk of prolonged power outages (due to Public Safety Power Shutoffs, bushfire damage, and delayed access for repairs) [3]

Rainfall & Flood

Lower total rainfall projected, but extreme rainfall to increase

By 2030 total annual rainfall across SA projected to decline by **4.4–9.0%*** - but the amount of rain falling in extreme rainfall events will increase & the frequency of extreme rainfall events will increase[1,2] between now and 2050, leading to potential:

- Increased risk of prolonged power outages (due to asset damage and delayed access for repairs) [3]

Note: excludes impacts of wind and lightning, as the impacts of these are less certain and less likely to impact SA.

[1] Data from Climate change Australia (CSIRO) Summary of weather for SA – forecasts are for mid-century (2050),

[2] Data from SA Climate Ready Initiative – uses a baseline period of 1981 to 2010.

[3] Examples of common climate risks and their impacts (NSW/ACT/TAS/NT Electricity Distributors Network Resilience: Collaboration Paper 2022)

Based on this engagement and analysis, SA Power Networks is taking the following approach to network resilience to extreme weather:

- **Bushfires** are a key risk for SA Power Networks and are likely to increase in frequency and severity due to climate change. Forecasts of climate change have not been factored into our modelling in support of our expenditure on network upgrades to mitigate bushfire risk, which relies on historic weather patterns. Instead, climate change has been considered as a sensitivity in the Bushfire Risk Mitigation business case to maintain conservativity in our forecast expenditures. We have also introduced a program to mitigate the risk of increased Public Safety Power Shutoffs.
- The impact of **heatwaves** on our network will need to be managed as part of a holistic approach to significant increases in peak demand in South Australia forecast by the Australian Energy Market Operator over the 2025-30 RCP, primarily due to forecast increases in large industrial loads as well as electrification. We are currently taking a measured approach to this forecast increase, recognising the affordability concerns expressed by our customers and erring on the side of conservatism while we further evaluate the potential for non-network solutions and flexible load connections to help manage this demand.
- Despite the River Murray floods experienced in 2022/23, the future impact of **floods** on our network due to climate change is currently uncertain. As a result, SA Power Networks is not proposing investment as part of the 2025-30 Regulatory Proposal to directly mitigate flood impacts.
- While there is little conclusive evidence on the impact of climate change on extreme wind and lightning in South Australia, the impact of **long duration, widespread outages** due to storms or other outage causes on community resilience in remote and regional areas has been acknowledged as an

issue for customers here and now. In order to mitigate these impacts, we are proposing the following investments in 2025-30:

  - an investment of $7.1 million in mobile generation to restore supply to customers in regional and remote areas during outages, while providing additional flexibility in managing the uncertain impacts of climate change such as heatwaves and floods (covered in this Business Case); and
  - provision within the Innovation Fund to investigate innovative and community-based options to increase community resilience during long duration, widespread outages.

- As our Stobie poles generally survive bushfires and floods, **ex-post repair costs** are less of a factor in our consideration of resilience. We have not yet identified any economic opportunities for ex-ante resilience investment to reduce ex-post repair costs, but will continue to monitor alternative network architectures, such as Stand-Alone Power Systems (**SAPS**) for viability.

Drivers for change for the Mobile Generation program

SA Power Networks services customers over a wide area of South Australia, with 70 percent of our assets dedicated to serving 30 percent of our customers. As a result, many of these customers are therefore serviced by long radial lines to minimise costs.

Restoration times in these areas can be extended due to the following factors:

- inability to restore supply from alternative parts of the network;
- increased exposure of long powerlines to both weather-related and non-weather-related faults;
- extended efforts required to locate faults;
- increased chance of weather events (such as lightning storms) impacting a large proportion of the network in a region, placing pressure on locally available resourcing; and
- challenges associated with obtaining safe access for repairs, which can be impacted by bushfire damage, flooding, heavy rainfall making access tracks inaccessible for vehicles, and high winds impacting on the ability to safely work at heights.

This has led to increasing inequity in the experience of our metropolitan and regional customers, as metropolitan customers are often able to avoid long duration outages with power being restored from alternate sources, and if they do experience a long duration outage, key community services are more likely to be available in nearby areas. In regional areas supplied by long radial lines, widespread and long duration outages can occur frequently as a result of both extreme weather events and other causes such as vehicle impacts and asset failure, and cannot be mitigated through alternate sources of network supply. The community's experience of these outages also differs in regional areas. In our customer engagement, we heard that the flow-on impacts of a power outage on other critical services, such as telecommunications, food and fuel, can often be as inconvenient as the power outages themselves. Given the large geographical area covered by these outages, it can be difficult to obtain these services from outside the outage area.

To better quantify the extent network resilience improvement solutions could avoid or reduce the duration of interruptions in regional areas, we have conducted a high-level review of historical outages over the last 12 years to produce a sample set of past outages (**sample outage set**), where approaches to reduce the duration of customer interruptions could be appropriate (note – this sample outage set has considered all outage causes, where a solution such as mobile generation could be appropriate, not just outages due to extreme weather).

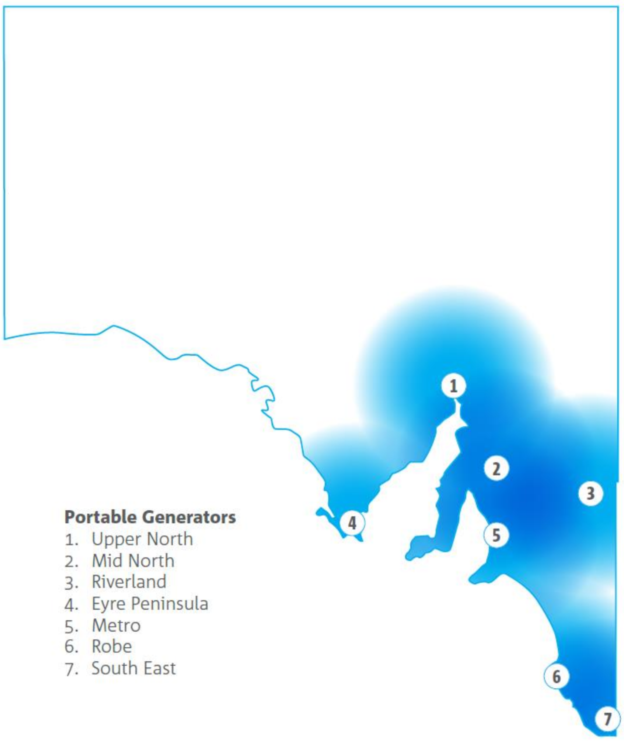
Given a consideration of this network resilience improvement program was the possible use of mobile generation, this review sought to identify outages where mobile generation could reduce the duration that customer supplies were interrupted. The criteria used to identify these outages were as follows:

- The avoidance of the outage was not being addressed through reliability programs.
- The outage related to major damage of the network such that a generation option could be a suitable solution to mitigate customer impacts during the repair.
- There was a high number of customers being interrupted within localised communities, rather than individual and wide-spread interruptions (ie a relevant use for the scale of mobile generation being considered here).
- The interruption duration lasted long enough that suitably located generation could be transported and connected in time to reduce the interruption duration.
- Multiple outages during the same event in the same area were excluded, as a single set of mobile generation plant would have been unable to be used for both outages.
- Long duration outages in metropolitan areas were excluded, where it was assumed that customers would be able to more easily make alternative plans due to the availability of power in areas geographically nearby to the outage, decreasing the customer service benefits of using mobile generation for these outages.

As part of that review, seven possible areas to base mobile generation were defined and preferred areas selected for each outage in the sample set. These seven areas were as follows:

- Upper North;
- Adelaide (and its surrounding regional areas);
- Eyre Peninsula;
- Robe;
- Mid North;
- Riverland; and
- South East.

Figure 2: Potential locations for mobile generation



This review has identified a sample outage set of 119 outages. Two thirds of the outages affected Rural Long feeders or their upstream sub-transmission network, and the remaining affected Rural Short and Urban feeders or their upstream sub-transmission network.

Approximately one third of the unsupplied energy[2] associated with the interruptions occurred on Major Event Days (**MED**s), and 55 percent of the unsupplied energy was associated with outages related to significant weather (eg wind, rain, lightning).

Figure 3 shows the distribution of the duration of the interruption to customer supply across the sample outage set, provided as the percentage of customer minutes interrupted[3]. This figure indicates that approximately 60 percent of the overall customer minutes interrupted (or unsupplied energy) associated with the sample outage set, is due to interruptions that lasted longer than 12 hours, with over 80 percent due to interruptions that lasted longer than six hours.

Figure 3: Interruption duration ranges in the sample outage set, provided as percentage of the customer minutes interrupted

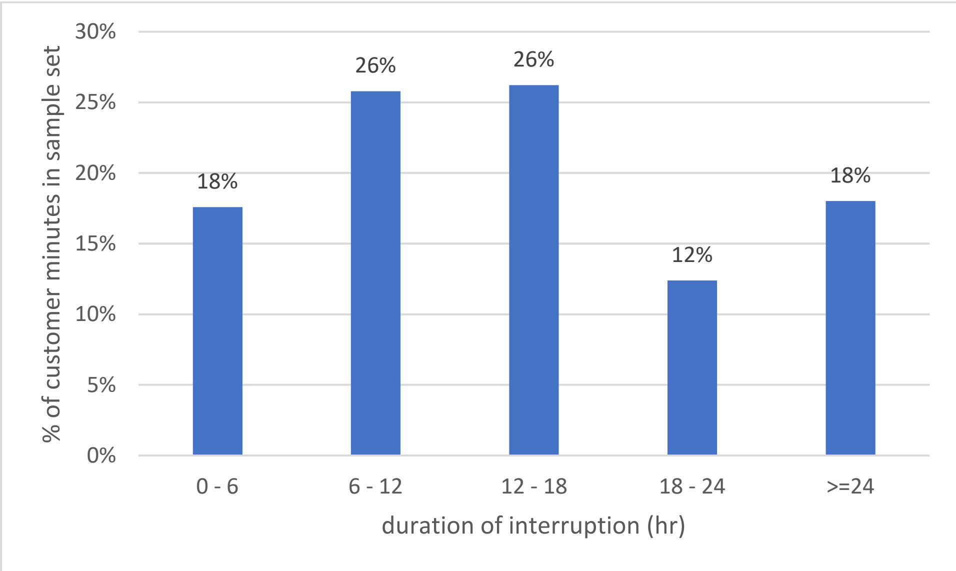


Table 1 summarises the key outage statistics that have been calculated from the sample outage set, for each of the seven candidate generation areas. The unsupplied energy and associated economic value have been calculated using our usual methods to estimate these amounts for reliability analysis[4].

2 Note, we estimate the unsupplied energy due to an outage based on the customer minutes interrupted for that outage (ie customers interrupted x duration of interruption) using the usual method we use for reliability calculations.

3 The customer minutes interrupted can be considered a proxy for the unsupplied energy due to the interruption, where we typically estimate the unsupplied energy via a factor that defines the average energy unsupplied (kWh) per customer minute interrupted.

4 This uses a kWh per customer minute interrupted and AER's VER figures, that has been calculated for this set of outages based on their network categories (ie Rural Long, etc) and these VCRs published by the AER in 2022.

Table 1: Summary of outage statistics by generation area

Generation areas	Outages per annum	average duration (hour)	average customers interrupted per outage	unsupplied energy per annum (MWh)	value per annum ($ millions)
Upper North	1.8	11.4	1,762	37.5	1.7
Adelaide	4.2	9.6	1,443	60.6	2.8
Eyre Peninsula	0.5	18.7	1,814	16.5	0.8
Robe	1.3	4.8	3,449	23.1	1.1
Mid North	0.8	10.8	1,807	15.9	0.7
Riverland	0.1	5.0	842	0.3	0.0
South East	0.6	15.1	1,413	13.9	0.6
All locations	**9.2**	**9.5**	**1,834**	**168.0**	**7.8**

These key statistics can be viewed as the 'supply risk' characteristics of the outage set, in terms of various average likelihood and consequence parameters, whereby the primary benefit of the options considered in Section 5 is the reduction in this supply risk (viewed as the value of the avoided unsupplied energy).

Important points to note from this table are as follows:

- The total economic value of unsupplied energy contained within the sample outage set is approximately $8 million per annum. This can be viewed as the upper limit of the annual benefit any option could achieve in avoiding similar outages ie the benefit of avoiding the outage itself, or having some form of fixed backup supply in place.
- The highest economic value is associated with the regional areas surrounding Adelaide, and with the Upper North.
- The Eyre Peninsula area has the longest interruptions, on average, but also has fewer outages per annum in the sample outage set resulting in a low amount of unsupplied energy or value.
- The Robe area has the most customers interrupted per outage, but has the shortest duration of outages, reducing the amount of unsupplied energy and value.
- The Riverland area has the fewest outages in the sample outage set, which are also of short duration and the lowest number of customers interrupted, resulting in the lowest unsupplied energy and value.

3.3 Industry practice

We have business-as-usual and special-purpose practices to manage our network prior to, during and after major weather events and other long-duration outages. These include:

- daily monitoring of weather forecasts to anticipate network impacts, including engaging with Weatherzone meteorologists;
- emergency management procedures to increase resourcing and support across the business in anticipation for, and in response to, major events;
- enhanced field / depot resourcing practices, including contracts with other service providers for these types of events. This included the use of Essential Energy crews in response to the 12 November 2022 storm event;
- post-event reviews for emergency events; and,
- review of major and long duration outages.

We consider that these practices are in line with good industry practice and align with the practices of other electricity distribution businesses in Australia and internationally.

Additionally, we consider that our use of Stobie poles tends to make our network more resilient (compared to wooden pole networks) by reducing the likelihood that major and extensive catastrophic damage to our network will occur due to extreme weather events and major incidents. We still suffer the effects of high winds, lightning and floods, causing extensive network faults, but typically this does not result in a large number of fallen poles which can require expensive repair, or the replacement of large sections of our overhead lines.

The capital programs proposed here should have enduring benefits that will enhance these existing practices and network arrangements. Most notably, they are aimed at efficiently reducing the longer customer interruptions that can occur as a result of extreme weather events and other impacts to critical radial lines.

Other electricity distribution businesses in Australia and internationally have recently undertaken or proposed capital programs to achieve similar aims. Most notably, Essential Energy is proposing a similar investment in mobile generation as part of its suite of programs aimed at improving the resilience of its network in its most recent Regulatory Proposal to the AER[5].

It is acknowledged that other solutions may be available to improve network and community resilience to extreme weather events. However, these solutions are generally novel, have uncertain costs and benefits, and / or are best delivered in partnerships with the exact partnering models uncertain. These solutions will be investigated as part of the Innovation Fund.

[5] Essential Energy, *10.06.11 Community Resilience Investment Case - Jan23 – Public.*

4 The identified need

4.1 Making our network more resilient to climate change

A possible effect of climate change is an increase in frequency and / or severity of extreme weather events[6], which are a major cause of network faults and customer interruptions. In considering potential responses to this driver, we engaged with our customers (discussed in Section 8), who indicated a preference to improve the resilience of our network to mitigate the possible effects of climate change.

An important objective of the Network Resilience Mobile Generation program is to make the network more resilient to extreme weather events.

4.2 Increasing net-benefits to SA Power Networks' consumers

A further important objective of the Network Resilience Mobile Generation program is to increase the net-benefit to SA Power Network's consumers by investing in network upgrades where the benefit of the investment (in terms of the expected improvement in reliability[7]) exceeds the costs of the investment.

4.3 Reducing the number of worst served customers

Through our consumer engagement (discussed in Section 8), our customers have indicated a preference to improve supply reliability to our worst served customers.

An important objective of the Network Resilience Mobile Generation program is to improve supply restoration times to a significant cohort of customers, particularly those communities most at risk to the extended interruptions that can occur following extreme weather events.

6 https://climatechangeinaustralia.gov.au/en/projects/esci/

7 The economic benefits associated with improvements in network reliability are quantified using the AER's VCRs.

5 Comparison of options

5.1 Defining credible and non-credible solutions to improve the resilience of network services

In **supporting document 5.8.4 – Network Resilience Mobile Generation Forecasting Structure - Methodology**, we set out a range of solutions we were considering to improve the resilience of the network to extreme weather events. We undertook a high-level qualitative evaluation of these solutions as an initial phase of the overall evaluation. Based on this evaluation, we have determined that only two solutions at this stage are likely to be credible solutions that will maximise the net-benefit associated with improving network resilience:

- the use of mobile generation (discussed in this business case); and
- an innovation fund (discussed in **5.7.7 - Innovation Fund - Business case**).

The use of mobile generation provides a relatively flexible low-cost solution to reduce the duration of customer interruptions that can be used across a wide area in response to a range of network outage causes. This solution will not reduce the costs associated with managing outages (ie emergency response and network repair costs), but as we noted in supporting document 5.8.4, this is not our primary driver of the need for this program.

Table 2 summarises our reasoning for deciding that the other possible solutions, summarised in supporting document 5.8.4, should be considered as non-credible at this stage. We may however reconsider some of these solutions as a new Resilience Improvement program for the 2030-35 RCP, as it becomes clearer how climate change may affect the resilience of our network and / or our customer preferences change.

Table 2: Summary of non-credible options

Focus	Aim	Scope	Cost and implementation comments
Network (assets and operations)	Avoid network faults and damage	Undergrounding	Given there is over 2,000 km of overhead HV feeder associated with the sample outage set then even if only a portion of this length (eg 30-50 percent) was upgraded, this would cost over $100 million. This will far exceed the $8 million of annual benefit available in the reference outage set in the short term. There could be other significant benefits associated with undergrounding (eg reduced vegetation management and line inspection cost, reduced bushfire risk, and improved reliability more generally). However, at this time, we consider it is unlikely these other benefits would be sufficiently high to justify this upgrade in all, but very limited, cases. We have not sought to include longer-life solutions which would require a significant time period to deliver net benefits to customers, in the interests of maintaining a conservative approach to our spend in light of affordability and deliverability challenges, as well as uncertainty as to whether more cost-effective approaches may be available in the near future.
		Covered / Aerial bundled cable (**ABC**)	Covered conductor and ABC can prevent some vegetation outages (eg faults caused by a single branch on the line) but are unable to prevent faults which bring wires to the ground (eg entire trees falling on the line). Long duration outages typically result from the latter due to the increased repair time, and hence covered conductor is unlikely to make a significant difference to the kind of faults which cause longer duration outages.
		Enhanced vegetation practices	Our outage reviews and line inspections already consider opportunities to apply enhanced vegetation practices to improve reliability (eg removal of hazard trees). In addition, due to the nature of the long, radial networks targeted by this program, vegetation impacts make a minimal contribution to the identified need. We do not consider that increasing these further is likely to improve resilience to a significant degree.
	Improve fault response / repair time	Enhance response and repair practices	As noted in Section 3.3, we already have enhanced practices to reduce the effects of extreme weather events on our network and network services. We do not consider that increasing these further is likely to improve resilience to a significant degree.

Focus	Aim	Scope	Cost and implementation comments
	Reduce customers interrupted, following fault	Increase segmentation and automation	Segmentation and automation reduce the number of customers interrupted following a fault by re-routing supply from unfaulted parts of the network. This is only feasible in areas where alternative sources of supply exist. The identified need this program addresses is long duration outages in areas supplied with radial lines, where no alternative sources of supply exist and hence segmentation and automation is not technically feasible.
		Increase network redundancy (ie by duplicating powerlines)	Given there is over 2,000km of overhead high voltage (**HV**) feeder associated with the sample outage set then even if only a portion of this length (eg 30-50 percent) was duplicated, this would cost over $100 million. This cost will far exceed the $8 million of annual benefit available in the reference outage set in the short term. We have not sought to include longer-life solutions which would require a significant time period to deliver net benefits to customers, in the interests of maintaining a conservative approach to our spend in light of affordability and deliverability challenges, as well as uncertainty as to whether more cost-effective approaches may be available in the near future.
Alternative supply arrangements	Removing network supply, thus avoid network faults	Alternative dedicated local supply - sub options of generation/ storage technology	Through our cost-benefit analysis, all mobile generation investments proposed in this business case have been found to only be viable if they can be shifted for use across multiple locations. As a result, dedicated local supply options have not been found to be viable. It is noted that the cost of these local supply options could be reduced by using the local supply option for multiple benefits, such as a community battery with a portion leased to a retailer. However, the commercial and partnership models for such options are nascent and are not yet at the level of certainty required for a business case. Therefore, these options will be investigated as part of the Innovation Fund, and may be considered as alternatives for areas where due to transport times, a mobile generator is not expected to be utilised frequently enough to be economically viable (eg Eyre Peninsula).
	Reduce customers interrupted, following fault	Alternative back-up local supply - sub options of generation/storage technology	

5.2 Mobile Generation evaluation methodology to define options

We have developed a cost-benefit analysis model to evaluate the costs and benefits of locating mobile generation in the seven areas discussed in Section 3. The model calculates costs and benefits for generation located in each of the seven areas for using the generation to resupply interrupted customers, based on reliability statistics calculated from the sample outage set. For each of the seven generation areas, the model estimates the ability of the generation to resupply the interrupted customers, and in turn, calculate the generation usage requirements and the anticipated reliability improvement through this use[8].

For the analysis of each generation area, it has been assumed:

- 3000 kVA capacity of mobile generation is available at each location[9], which is able to supply a maximum of 1,364 impacted customers. This is sufficient to ensure key community services are prioritised in line with customer engagement feedback.
- It would take on average six hours to transport and connect the generation to mitigate the effect of the outage.

Outages have been excluded where it was considered that the generation would be unlikely to be used for mitigating the effects of that outage. These exclusions covered:

- multiple outages in a generation area associated with a single event (ie major storm), where only the worst case outage for that event was assumed to be able to be mitigated by the generation; and

[8] For the analysis of the sample outage set, it is assumed that the generation assigned to a specific area can only be used to reduce the interruption duration for the outage that has been assigned to that area.

[9] This capacity assumption is based upon a typical mobile generation arrangement, developed by our operations subject matter expert, which is relevant to mitigating the scale of customers being interrupted in this outage set. This allows for a 1,250kVA unit and a 500kVA unit at each storage location. This generation can resupply approximately 800 interrupted customers.

- outages in the Adelaide metro area, where powerlines are shorter and more easily accessed for repairs, and where long duration outages are more typically related to the large number of faults relative to the available workforce (as opposed to the time taken to locate and repair a single fault or small number of faults).

The costs of the mobile generation at each location is estimated based on the following:

- the capital cost, which has been developed based on a high-level scope and cost estimate, allowing for the generation plant cost, transport vehicles, fuels storage, ancillary and connection equipment, and depot installation / storage;
- usage costs, which include energy / fuel costs associated with resupplying customers, transport costs (ie from its storage location to where it is needed), and other operating costs (ie the resource requirement when it is in use); and
- maintenance costs (eg the routine and corrective maintenance that may be required through its life to ensure it operates when required)[10].

The cost-benefit analysis model provides further details and values of the specific assumptions we have used for the analysis.

Table 3 summarises the key results from the cost-benefit analysis of the seven generation areas. More detailed results of each area are provided in the model. Key points to note from these results, which are relevant to our selection of options, are as follows:

- Locating generation to support the regions surrounding Adelaide and Upper North areas provide the greatest net-benefit.
- Locating generation to support the South East is the next highest ranked area, with a smaller, but still significant net-benefit.
- Locating generation to support the Mid North area is the next ranked area, with a minimal net-benefit.
- Locating generation to support the Eyre Peninsula, Robe and Riverland areas are the lowest ranked areas, with no net-benefit.

It is noted that the net present value shown in Table 3 assumes each generator is purchased in year 0 of the regulatory period, whereas actual expenditure and benefits will be staggered throughout the regulatory period.

[10] This is not expected to be a significant component of the overall lifetime cost of the generation (including capital). Therefore, the average annual maintenance costs are estimated to be 1 percent of the capital cost.

Table 3: Summary of generation area cost-benefit analysis results

	Mobile generation area ($ millions)						
	Upper North	Adelaide	Eyre Peninsula	Robe	Mid North	Riverland	South East
Capex	2.4	2.4	2.4	2.4	2.4	2.4	2.4
Total life-time costs (present value - Y0)	2.7	2.8	2.7	2.7	2.7	2.6	2.7
Total life-time net benefits (present value - Y0)	3.5	3.6	-0.4	-1.8	0.1	-2.6	1.8
Net benefits ranking	2	1	5	6	4	7	3

5.3 The options considered

The cost-benefit analysis model results discussed previously have been used to define the five options (including a 'do nothing' option) and to calculate the costs and benefits of each option. Each option is defined in terms of the generation areas included in that option, as summarised in Table 4.

Table 4: Summary of options considered

	Included generation						
	Upper North	Adelaide	Eyre Peninsula	Robe	Mid North	Riverland	South East
Option 0 ('do nothing')							
Option 1 ('economic')	✓	✓					✓
Option 2 ('all generators')	✓	✓	✓	✓	✓	✓	✓

5.4 Analysis summary and recommended option

5.4.1 Option evaluation results

Table 5 summarises the results of our cost-benefit analysis of the options set out in Table 4. Table 6 shows the average generation usage for each option and Table 7 shows the reliability improvements achieved by each option (for the sample outage set only)[11]. It is noted that the net present value shown in this table assumes each generator is purchased in year 0 of the regulatory period, whereas actual expenditure and benefits will be staggered throughout the regulatory period.

[11] These two tables omit Option 0 ('do nothing') as there is no generation usage or reliability improvement associated with this option.

Table 5: Costs and benefits of options ($ million)

	Option 0	Option 1	Option 2
Total Capex	0.0	7.1	16.5
Total operating and maintenance costs - average per annum	0.0	0.1	0.2
Total life-time costs (present value - Y0)	0.0	8.2	18.8
Total life-time benefits (present value - Y0)	0.0	19.2	23.2
Total life-time net benefits (present value - Y0)	0.0	11.6	4.4

Table 6: Summary of generation usage by option

		Option 1	Option 2
Uses - per annum	(uses)	3.6	6
Energy delivered - avoided unsupplied energy - per annum	(kwh)	33,434	45,134
Utilisation (energy basis) - per annum	(%)	0.04%	0.02%
Utilisation (time basis) - per annum	(%)	0.13%	0.07%

Table 7: Summary of reliability improvement (for the sample outage set only)

Without generation		**Option 1**	**Option 2**
Average outages per annum	(outages)	6.58	9.22
Average customer interruptions per annum	(customers)	10,050	16,900
Average interruption duration per customer interrupted	(hr)	10.60	9.45

With generation		**Option 1**	**Option 2**
Average customer interruptions improved per annum	(customers)	3,757	6,708
Average customer interruptions improved per annum	(%)	37%	40%
Average reduction in interruption duration - improved customers	(hr)	8.46	6.40
Average reduction in interruption duration - improved customers	(%)	80%	68%

5.4.2 Recommended option

Our recommended option is Option 1. This option allows for the investment in a total of 9.0MVA of mobile generation, that can service three areas covering the Upper North, regions surrounding Adelaide, and South East.

The $7.1 million capital cost of this option should allow us to improve the resilience of supply to on average 3,757 customers per annum, reducing long duration outages by approximately 8.5 hours, based only on the sample outage set. However, the number of customers with improved supply resilience is likely to be considerably higher than this, through other uses of the generation such as maintaining supply to customers during planned work, managing risk associated with the capacity of the network during peak demand, and responding to uncertain future events associated with climate change such as floods.

We have selected this as our preferred option as it:

- addresses the identified needs discussed in Section 4;

- represents a low-risk solution in terms of its implementation as it represents technology we have experience using; and
- strikes a conservative balance between the preferences of our customers to improve the resilience of supply to critical services in regional and remote communities, and the need to ensure all investment is economically viable according to the existing VCR measures and robust to sensitivities which are discussed in section 5.5.

This option allows for the three areas that have a positive net-benefit when allowing for the sample outage set alone, giving it the highest net-benefit.

Based on the review of these options and cost-benefit results (both from a bottom-up review by relevant internal subject matter experts and the top-down challenge applied across our proposal forecasts), we have rejected the other options primarily for the following reasons.

Option 0 (do nothing)

This is the least cost option, but it does not address the identified needs. It also increases the likelihood that the resilience of the network could degrade further over the next RCP due to climate change.

We do not consider that this option aligns with our customer and stakeholder preferences, particularly given that other credible options have appreciable net-benefits in terms of improving resilience.

Option 2

Option 2, which includes all potential generator locations, is the highest cost option. Furthermore, given four of these locations have a negative net benefit, the overall net benefit of this option is approximately one third of the recommended option.

This option improves the resilience of supply to the greatest number of customers, 6700 customers, and provides the greatest level of flexibility to respond to uncertain events (for example, by including a generator for the Riverland to assist with the response to a future flood). However, the benefits for these events have not been able to be quantified based on historical data.

5.4.3 Non-quantified benefit provided by recommended option

Material non-quantified benefits of the recommended options could include avoided Guaranteed Service Level (**GSL**) payments associated with avoided interruptions that have resulted in GSL payments.

These non-quantified benefits have been assumed to be too small, compared to the benefit of reliability improvement, to warrant their estimation for the evaluation of individual options. They are also likely to be offset by the operating costs of the mobile generation, which we are not proposing an opex step change for. However, their significance is discussed further in Section 7 below, when we discuss the regulatory treatment of the program within our proposal.

5.5 Scenario and sensitivity analysis

We assessed the sensitivity of the findings of the cost-benefit analysis of the options to changes to key assumptions. The results of this analysis is summarised in Table 8 which provide the net-benefit (over the life of the generation) for the sample outage set. These results indicate that changes in key assumptions result in no change in the ranking (in terms of the greatest net-benefit) of the option relative to the base case.

Given these results, we consider that the reasoning provided in Section 5.4 for our selection of the recommended option is still valid, in light of a reasonable range in the key assumptions.

Table 8: Sensitivity studies – lifetime net-benefit (sample outage set only)

	Option 1	Option 2
base case	**9.0**	4.4
discount rate lower (3.5%) (4.05% base case)	**9.7**	5.3
discount rate higher (4.5%) (4.05% base case)	**8.5**	3.7
option capital cost higher (+20%)	**7.4**	0.7
option capital cost lower (-20%)	**10.6**	8.0
VCR higher (+20%)	**12.4**	9.0
VCR lower (-20%)	**5.6**	(0.3)
transport time shorter (4 hours) (5 hours base case)	**10.8**	7.3
transport time longer (6 hours) (5 hours base case)	**7.3**	2.0
outage use less (80%) (100% base case)	**5.6**	(0.2)
outage use more (120%) (100% base case)	**12.4**	8.9

6 Treatment in our regulatory proposal

6.1 Implications on STPIS settings

We have included $7.1 million in our capex forecast to cover the full capital costs for the Network Resilience Mobile Generation program over the next RCP. We do not expect the Service Target Performance Incentive Scheme (**STPIS**) to provide sufficient incentive to undertake this type of program. This is due to the total expected STPIS benefit returning only $4.5 million over the 2025-30 RCP which is less than the program cost.

Nonetheless, we still anticipate that the Network Resilience Mobile Generation program could produce a small improvement to the underlying reliability measured through the STPIS. Therefore, rather than adjusting the capex forecast for this program to allow for this, we have included the following downward adjustments to the STPIS targets for the next RCP:

- System average interruption duration index (**SAIDI**) targets (ex. MEDs) – 4.11 minutes to Long Rural feeders, 0.69 minutes to Short Rural feeders, and 0.08 minutes to Urban feeders; and
- System Average Interruption Frequency Index (**SAIFI**) targets (ex. MEDs) – there is no adjustment to SAIFI targets as this program does not avoid the interruptions; it only reduced their duration.

It is important to note that the STPIS target adjustments will occur incrementally over the next five-year RCP as the program is rolled out over this period.

6.2 Implications on other costs

As discussed in Section 5, we have not quantified offsetting capex-opex trade-offs in our cost-benefit analysis. Nonetheless, we expect that there could be some capex-opex trade-off due to GSL payments achieved by the program. However, this small reduction in opex is likely to be offset by the additional operating and maintenance costs of the new generation.

We are planning to absorb any net opex increases associated with this program.

7 Deliverability of recommended option

No significant deliverability risks have been identified for this program, as:

- the program is an extension of our existing emergency response capability deploying mobile generation;
- staggering the implementation of this program across the five-year regulatory period will enable sufficient time to develop the skills and capabilities needed to deploy the generation; and
- the program represents a modest investment in resilience, avoiding the challenges of scale associated with other options (eg improving network redundancy).

SA Power Networks has developed a plan to ensure that it can deliver the increased volume of work reflected in the programs that comprise our total network expenditure forecast in our Regulatory Proposal. This plan considers the detailed implications of our proposed overall uplift in total network expenditure for our required workforce and supporting internal services of information technology, fleet, property and human resources.

We consider that our plan is realistic and achievable over the 2025-30 RCP. The details of our approach are set out in our **supporting document 5.2.5 - Resourcing Plan for Delivering the Network Program**.

8 How the recommended option aligns with our engagement

8.1 Alignment to customer expectations

The service outcomes that are enabled by the expenditure and programs proposed in this business case, are aligned to achieve outcomes that were directly supported by our customers as ultimately reflected in the recommendations of the People's Panel. This is noting that:

- the topic of resilience has been a key focus of our consumer and stakeholder engagement program. One of our four key themes that have framed our engagement under a desire to 'focus on what matters' to our customers has been the theme of a 'reliable, resilient and safe electricity network';
- in engaging on this theme, and under the specific topic of resilience, we undertook a series of deep-dive workshops called 'Focused Conversations' with a broad range of consumer, industry, government and regulatory body representatives. In these Focused Conversations we sought recommendations on the service outcomes that customers prefer and expect;[12]
- with particular regard to the program covered in this business case, we engaged on the identified needs by seeking feedback on what network and community resilience means to customers and their existing and future concerns, how resilience is considered in our current expenditure and programs, and potential future solutions to improve network and community resilience;
- we then posed three scenarios, and ultimately engaged on four as directed to by our customers, in terms of how we could respond to the identified need, and the expected outcomes for customers in relation to service, expenditure and price – these included (1) and (2) doing nothing, (3) two targeted and efficient resilience programs (mobile generation and the Innovation Fund) and (4) extensive SA Power Networks'-owned investment in network and community resilience even where it is not efficient for customers;
- while our customers and stakeholders were consistently mindful of energy affordability concerns, the Focused Conversation arrived at a clear consensus recommendation to the People's Panel as the next stage in our engagement program, that SA Power Networks should invest sufficiently in order to:

    1. reduce the impact of long-duration outages on regional and remote communities; and
    2. investigate innovative solutions and partnerships to build network and community resilience; and

- ultimately, the People's Panel deliberated on and affirmed the results of the Focused Conversations in their formal recommendation, and SA Power Networks has committed to taking this recommendation forward as reflected in the recommendations contained in this business case.

Since conducting the People's Panel process, we published a Draft Proposal to play back how we have given effect to customer recommendations and to confirm that those recommendations remain valid given continued cost of living pressures and to obtain further input to refine our Regulatory Proposal.

Submissions received on our Draft Proposal suggest that the recommendations of the People's Panel remain valid with respect to this Resilience Program, noting that:

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[12] This was covered in workshops 1, 3 and 4 for the Reliability and bushfire safety Focused Conversation. Materials presented at the Focused Conversations are available on our TalkingPower website under the page titled 'focused conversations'. [https://www.talkingpower.com.au].

- members of the People's Panel affirmed that their recommendations, including in respect of resilience expenditure as set out in this business case, remain current;[13]
- the Regional and Remote Customers Sub-Committee of our Community Advisory Board (**CAB**) who oversaw regular close engagement with SA Power Networks on resilience matters, outlined that it supported the modest investment proposed to procure three mobile generators to address concerns raised by customers in relation to long-duration outages;[14]
- the South Australian Department of Energy and Mining supported the program to enhance resilience via additional mobile generators;[15]
- the Small Bsiness Commissioner of South Australia also supported the resilience program, particularly due the contribution to that this program will make to regional customers;[16] and
- a submission from an individual, considered that even greater action on climate change and resilience is needed than being proposed by SA Power Networks.[17]

8.1 Alignment to Customer Values Research

To guide the development of expenditure forecasts that enable price-service outcomes that align with the expectations and preferences of our broader customer base, we engaged expert economic consultants Marsden Jacobs to undertake a Customer Values Research survey on customers' willingness to pay for particular service outcomes. The research employed a partial profile discrete choice experiment to identify how much South Australian households and businesses are willing to pay through their electricity bills to achieve certain service outcomes.

One service outcome of focus for the study was to identify how much customers may be willing to contribute on their annual electricity bills to reduce the number of customers who may experience service interruptions per year longer than 24 hours due to extreme weather.

It is important to note that the results in relation to this service outcome indicate the customer base's willingness to contribute more on their electricity bills to achieve a service outcome for a minority group of customers and is therefore a willingness to subsidise. This is distinctly different from a willingness to pay type measure, where the survey participant is indicating their willingness to pay to receive a service outcome for themselves.

The survey results indicated with a 95 percent level of confidence that, on average, residential customers are willing to contribute an additional $8.75 per year, and commercial customers an additional $6.24 per year, on their electricity bills to improve service levels for 24,000 customers on average per year that experience service interruptions longer than 24 hours each year.

Our recommended option for the Resilience Improvement program will improve service levels for 2,700 customers on average per year who experience service interruptions for six hours or longer. We expect the cost of the program will have an annual residential bill impact of $0.39 and commercial bill impact of $2.73.

13 DemocracyCo, *Submission: SA Power Networks Draft Regulatory Proposal 2025-30*, 30 August 2023.

14 RRC-SC, *Submission by the Regional and Remote Customers CAB Sub-committee*, 28 August 2023.

15 DEM, *SA Department for Energy and Mining – Submission*, 12 October 2023.

16 SBCSA, *Consultation on SA Power Networks 2025-30 Draft Regulatory Proposal*, 1 September 2023.

17 Private individual, *submission via email – draft proposal feedback*, 8 August 2023.

9 Alignment with our vision and strategy

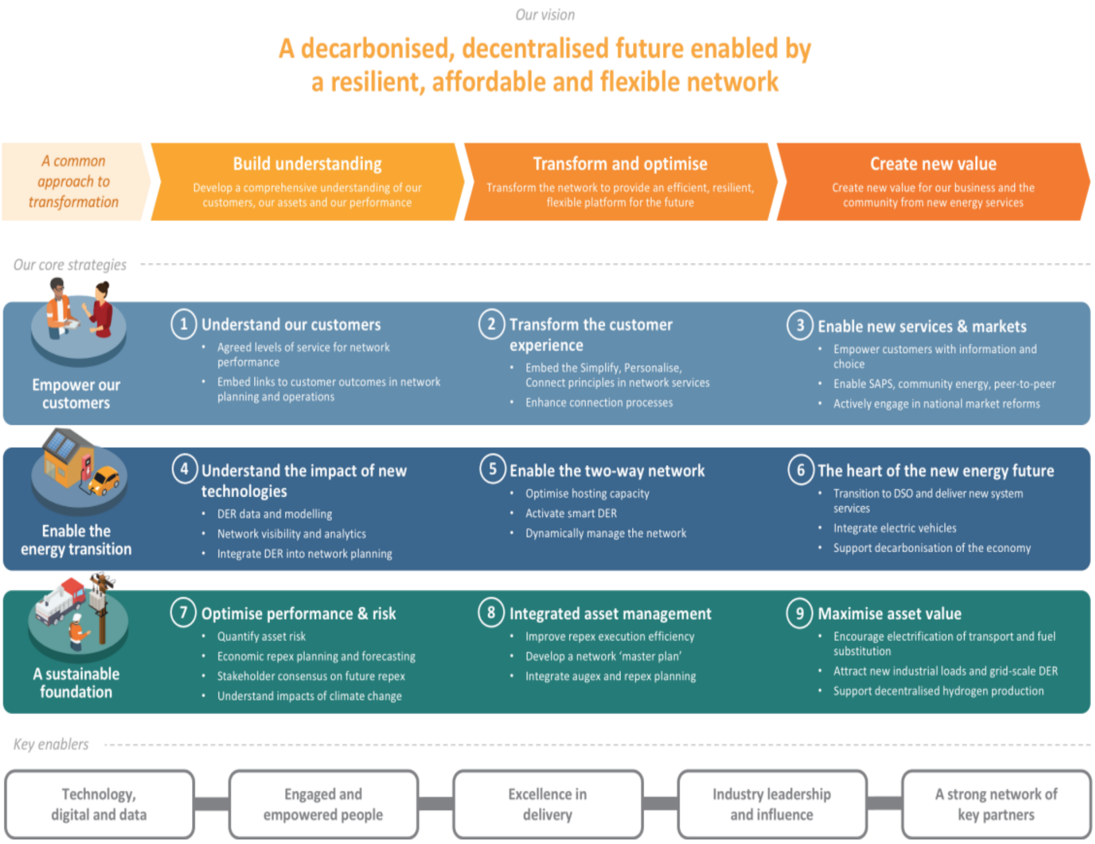
This business case proposes expenditure to allow us to achieve an overall service outcome of improving the network's resilience for customers who experience prolonged outages that typically result from extreme weather events, is aligned to progress our overall company 'Network Strategy' and our vision within this strategy, displayed in Figure 4.

This is noting that the program recommended in this business is aligned to several of the core strategies within the Network Strategy, as follows:

- 'empower our customers' – the program arises from a comprehensive, multi-staged consumer engagement program that saw us iterating our expenditure forecasts with our customers over five iterations to identify and align our expenditure to achieve the service level and price outcomes that our customers expect and prefer being mindful of alternatives and tradeoffs;
- 'a sustainable foundation' – the program provides outcomes for customers that:
  - are more equitable for customers across our network;
  - are efficient for customers – producing monetised value for customers, quantified by assessing the impact of network risks on customer service outcomes under an option versus do-nothing counterfactual; and
  - providing upgrades that provide additional network resilience to potential emerging effects of climate change.

It is acknowledged that there are other options to address this need, such as community energy, which are more in alignment with our long-term vision and strategy. However, the ability of these options to provide immediate, cost-effective impact at scale during the next regulatory period remains uncertain. These options will be investigated in parallel as part of the Network Resilience Community Fund.

Figure 4: Network strategy and vision



10 Reasonableness of cost and benefit estimates

We believe that our assumptions are reasonable, and our cost-benefit analysis methodology used to prepare the program forecast should align with the recent AER statements on its expectation for formal quantitative risk assessments and cost-benefit analysis.

The key features of our approach that we believe demonstrate the appropriateness of our assumptions and analysis are as follows:

- We have undertaken a review of historical outages to identify a sample of past outages, where the availability of mobile generation could have reduced the duration of the interruptions. We have used this sample outage set to estimate the likelihood and consequences of outages, customer interruptions and the duration of interruptions in order to quantify the benefits of using mobile generation to reduce the duration of customer interruptions.
- We have quantified the benefits associated with the economic value of avoided unsupplied energy of the generation using the equivalent approach that we adopt for our reliability evaluation. This uses the AER's 2022 VCR's and weights these by average energy used across feeder types across the affected regions.
- It is worth noting that the interruption duration of the sample outage set that has informed our cost-benefit analysis typically ranged between six and 24 hours, and therefore, we consider that the AER published VCR is a reasonable value for our analysis, in the absence of an alternative.
- We have allowed for both the capital and operating costs of the generation, and conducted net present value analysis, over an asset life of 15 years, based on our estimates of its usage and a set of cost assumptions. The capital cost estimate, which is the major component of the lifetime cost, has been developed from a reasonably detailed scope, and costs developed by our operations subject matter experts based on their knowledge of mobile generation equipment we currently have and associated transport, ancillary equipment, and storage facilities necessary for its use.
- We have undertaken cost-benefit analysis across a range of options, defined by the extent of the areas in South Australia that can be serviced by the generation, to determine the recommended option.