Opportunities for stand-alone power systems to enhance network resilience

Final Report

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Executive Summary

The capacity for electricity networks to prepare, absorb and recover from natural hazard events is referred to as resilience.[1] This year has seen an unprecedented number of cost pass through applications being made by electricity network businesses to recover costs sustained to network infrastructure from natural hazard events including bushfires[2], severe storms[3] and winds[4] from extreme conditions experienced across Australia in 2019 and early 2020.

Natural hazard events have significant cost implications for network businesses and the economy more broadly. Maintaining power supply is linked to the ability of communities to absorb and recover from these types of events. Findings from a study commissioned by the Australian Business Round Table for Disaster Resilience and Safer Communities indicate that natural disaster events cost the economy on average $13 billion every year,[5] highlighting the need for proactive measures.

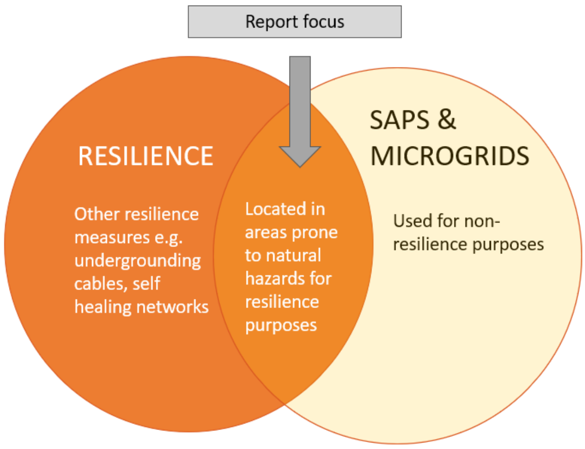
The issue of network resilience is likely to continue to grow in importance, given that the severity and frequency of extreme weather events in Australia are almost certain to increase over coming years as a result of climate change.

Scope and objectives

Given the breadth of this issue, this report takes a relatively narrow, but important focus in exploring the potential for Stand Alone Power Systems (SAPS) to improve electricity network resilience in areas prone to natural hazard events.

Specifically, the report identifies whether there is potential for a positive business case for network investment in resilience-based SAPS by examining three case studies. These are intended to be representative of a remote densely forested area in South Eastern Australia prone to bushfire events.

Figure 1 - Report scope and focus



- Case Study 1: Provision of an **isolated SAPS to a remote town** of approximately 500 customers, which is capable of supplying the township's entire demand. The township is then completely disconnected from the network.
- Case Study 2: Provision of **individual isolated SAPS** to 60 customers, which are capable of supplying the customers' entire demand. The customers are then completely disconnected from the network.

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[1] Bushfire and Natural Hazards CRC, *The Australian Natural Disaster Resilience Index: A system for assessing the resilience of Australian communities to natural hazards, Chapter 1*, July 2020
[2] AusNet, *Cost pass through application – 2020 Summer Bushfires*, 27 May 2020.
[3] Ausgrid, *Ausgrid pass through application 2019/20 storm season*, 31 July 2020.
[4] AusNet, *Cost pass through application – 500kV Transmission Line Tower Collapse*, July 2020.
[5] Deloitte Access Economics, 2017, *'Building resilience to natural disasters in our states and territories,'* a report prepared for the Australian Business Round Table for Disaster Resilience and Safer Communities, p. 16.

- Case Study 3: Provision of an islandable power system to a remote town of approximately 500 customers which is capable of supplying around 45% of the township's ordinary demand. The township is ordinarily connected to the network and only becomes islanded during an outage.

The report further reviews the current regulatory and consumer protection settings to identify potential gaps and barriers to network investment in SAPS for resilience purposes.

Despite the narrow focus and limits of the model created for this study, the findings have ramifications for how network businesses, regulators and policy makers will increasingly need to determine the most efficient way for mitigating against the potential impacts of climate change on network infrastructure and the corresponding implications to consumers in terms of reliability of supply and costs. This study also raises implications regarding power supply arrangements and the ability of communities to recover from major event days.

Findings: modelling of Case Studies

Our modelling identified that the business case for a network business to invest in SAPS is variable. It is also highly dependent on locational characteristics such as the size and types of load to be supplied and, of particular importance, the assumed frequency of natural hazard events. In some circumstances, DNSPs are already finding that locational characteristics of certain sites result in a positive business case. Consequently, the inclusion of 'resilience' benefits in these cases further strengthens the business case for adopting a SAPS solution.

As theoretical case studies, they may not provide a true indication of the opportunity for resilience-based SAPS, and importantly do not take into account financial modelling implications from the AEMC's delivery model for SAPS.

Table 1 – Modelling results

	Case Study	Total Benefits (PV)	Total Costs (PV)	Net Present Value	Frequency of natural hazard event required to make a positive business case (% likelihood per year)
1	Isolated SAPS to remote town	$34.6M	-$43.2M	-$8.6M	7.6%
2	Individual isolated SAPS	$22.8M	-$19.6M	$3.2M	2.4%
3	Islandable power system to remote town	$13.2M	-$16.5M	-$3.3M	7.4%

Our findings show that the business case for isolating remote towns (Case Study 1) is likely to be generally negative. Notwithstanding, there is still the potential for there to be some locations with certain combinations of relative remoteness, small populations, existing unreliable power supply and feeders nearing the end of their useful asset life that would justify investing in SAPS from an economic perspective.[6] The business case assumed existing solar systems could be incorporated into the SAPS to reduce overall

[6] We have not modelled the full range of permutations, but the sensitivities conducted indicate that when these parameters are all pushed towards the most extreme but still plausible end of the spectrum, a positive business case can be made. There is no one threshold for each of these parameters at which the business case becomes positive. However, certain combinations of these parameters will create a positive business case.

cost. However, the capacity of existing solar was not material to the business case owing to its relatively low cost compared with battery storage.

The business case for the islandable remote town (Case Study 3) is also likely to be generally negative, even where only a small number of facilities are supplied when islanded. Although the cost of the system is less than for a fully islanded town, the benefits are limited as the feeder must still be maintained. This business case assumed existing solar systems could be incorporated into the SAPS to reduce overall cost.

These findings assume that the probability of a major natural hazard event impacting a town in any given year is 4%.[7] Our modelling indicates that if this increases to around 8% or more, then there is likely to be a compelling resilience-based business case for provisioning some remote towns with either islandable or islanded SAPS. Climate change projections suggest it is plausible that the probability of a bushfire event impacting a town in a bushfire prone area will increase beyond 8% before 2050.[8]

The business case for providing individual SAPS to 60 single customers (Case Study 2) produced a higher economic benefit than provisioning a township due to the lower capital cost and realisation of the same network benefits.

Findings: regulatory review

All network businesses in Australia have a legal obligation (under various state-based legislation) to manage safety risks arising from the protection of the environment, including protection from ignition of fires by electricity networks and safety aspects arising from the loss of electricity supply. However, the extent to which networks consider resilience measures in terms of mitigating or managing these impacts varies. The consideration of the role of SAPS in a safety context has generally not been categorically considered but is starting to emerge as a theme that DNSPs are now seeking to address.[9] Consideration of SAPS in this context is likely to further grow in importance in light of recommendations from the New South Wales (NSW) Bushfire Inquiry and the release of findings from the Royal Commission on Natural Disasters.

It is important to note that the regulatory framework for SAPS is an area that is still evolving. The Australian Energy Market Commission (AEMC) has recently published a suite of proposed rule changes as part of its Final Report on Updating the Regulatory Frameworks for Distribution Network Service Provider (DNSP) led SAPS.[10] While the proposed changes to the National Electricity Rules (NER) and National Electricity Law (NEL) are likely to address several key barriers associated with implementing SAPS solutions, the proposed changes are unlikely to address the resilience-related barriers identified as part of this study.

Findings from our regulatory review, indicate that several areas of the regulatory framework are potentially constraining the ability of network service providers (NSPs) to enhance their networks' resilience to natural hazard events. Developing a business case to support network resilience is likely to be difficult for NSPs under current arrangements due to the lack of an agreed industry approach for:

- Valuing reliable supply of electricity following a long duration localised outage; and

[7] Y. Zhang, S. Lim, J.J. Sharples, Development of spatial models for bushfire occurrence in South-Eastern Australia, 2015
[8] Refer to discussion on bushfire probability on pages 12-13.
[9] We note that some DNSPs, including AusNet, Ausgrid, and Essential Energy are considering investing in SAPS in remote areas of its network to avoid significant capital expenditure, deliver other benefits to customers, and assist in mitigating the risk of damage to its assets from bushfires.
[10] AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, Final report, 28 May 2020.

- Assigning probabilities to the frequency of occurrence of natural hazard events.[11]

Further, there is no positive requirement under the existing framework for NSPs to make investments for resilience purposes. While the Service Target Performance Incentive Scheme (STPIS) balances the effects of the Capital Expenditure Sharing Scheme (CESS) and Efficiency Benefit Sharing Scheme (EBSS) so that electricity customers do not experience a deterioration in their reliability or service levels, as a result of efforts by distribution networks to improve efficiency, this mechanism focuses on reliability only. It does not incentivise improvements in resilience such as measuring DNSPs' ability to recover quickly from major event days.

Our findings indicate that current regulatory arrangements place greater emphasis on managing network resilience through recovery measures, such as via holding insurance or the cost pass through mechanism. Current arrangements do not adequately support or incentivise other measures that look at mitigating the impacts of, or absorbing the impacts from, natural hazard events. This is a concern given the increased frequency in which natural hazardous events are occurring and the growing trend for insurance providers to withdraw coverage for natural hazardous events.

This trend, if not addressed, is likely to create an over reliance on the pass through mechanism which in the long-term may not be the most efficient mechanisms for mitigating against these types of risks.

Recommendations

To address the regulatory issues identified above we have proposed the following recommendations.

Recommendation 1 Engagement on resilience	DSNPs to proactively engage with their customers and customer advocacy groups to better understand customer expectations, priorities and value placed on resilience-based SAPS. The engagement should seek to determine the level of customer support for proactive investment by DNSPs in resilience.

[11] It is expected that further guidance from the ESCI project will be forthcoming in 2021. This will include probabilistic treatment of individual severe weather events, and potentially an alternative approach for compound severe weather events

Recommendation 2 Potential rule change request	Where customer support is achieved and/or where other stakeholders (e.g. customer advocacy groups) separately identify customer value for network investment in resilience, then there may be a strong case for a rule change request to be submitted. Any such rule change should require, inter alia, an explanation of the distinction between resilience and reliability, and the relevance of resilience to the NEO. Any rule change request should consider the following elements: • A definition of resilience • A requirement for the AER to create a resilience guideline including: o A risk assessment framework: we expect that this will be forthcoming in 2021 from the Electricity Sector Climate Information project. This will include probabilistic treatment of individual severe weather events, and potentially an alternative approach for compound severe weather events. o Changes to the AER's VCR framework to recognise the costs of long duration but localised outages, potentially including social costs based on recent Australian data. o Changes to the STPIS Beta 2.5 methodology to reflect the increasing number and severity of major event days (MEDs). • Changes to chapter 6 related to forecast capex and opex to require DNSPs to "maintain the reliability, security and resilience of the distribution system through the supply of standard control services" (6.5.7(a)(3)(iv)). • Changes to broaden the considerations that a DNSP is able to consider in determining whether to transition existing customers to a SAPS to include improved resilience. • Consideration of the impact of a resilience requirement on other incentives (e.g. the CESS and EBSS). • Consideration of any impacts on jurisdictional reliability standards.
Recommendation 3 Consideration of resilience in Electricity Network Safety Management System (ENSMS)	The development of natural hazard management (resilience) plans, which may include bushfire management plans and/or other natural hazards such as cyclones as appropriate, setting out: • Specific activities, including capital expenditure programs and operational or maintenance expenditure programs undertaken to reduce the risk of a network asset igniting a bushfire • Specific activities including capital expenditure programs and operational or maintenance expenditure programs undertaken to reduce the impact of any natural hazard on the network asset (which may include replacing the asset with SAPS) • Capacity to manage and respond to natural hazard events through appropriate emergency response programs, customer information systems, public communications strategies and resourcing levels. In preparing natural hazard management plans, as set out in AS5577, NSPs should also engage with state governments and emergency services to clearly set out responsibilities for emergency supply of power immediately following an emergency event. Further investigation may also be required to determine whether emergency systems and SAPS standards should be set at a national or state level.

We also recommend the following studies are undertaken to further investigate the issues identified in this report.

Recommendation 4 Deep dive SAPS Case Study	An in-depth case study should be carried out based on an actual town recently impacted by a natural hazard event (such as Mallacoota or Bawley Point) to better understand: • Financial modelling implications under the AEMC's proposed third-party ownership of the generation component of SAPS installations • Network configuration requirements and what control systems would need to be put in place • The customer value of reliable power during and immediately following natural hazard events • The community views on the design parameters for an islandable SAPS, including consideration of the number of types of facilities where a resilient power supply is highly desirable. • The community willingness/ability to reduce demand below normal levels after a natural hazard event • The relative risks and benefits of a diesel supplied SAPS or solar/battery supplied SAPS, including consideration of diesel transport and long-term diesel use after a natural hazard event
Recommendation 5 Resilience-based SAPS technical study	A technical study should be undertaken aimed at mitigating potential technical issues for islandable SAPS including, but not limited to, consideration of: • How behind the meter Distributed Energy Resources (DER) interact with SAPS, including consideration of efficiently and safely isolating any premises within the SAPS impacted by the natural hazard event. • Expanding on the work undertaken by Horizon Power's Onslow Renewable Energy Pilot[12] to examine the ability of inverters in behind the meter DER to operate independently or participate after an outage, including consideration as to how electric vehicles (EVs) with vehicle to grid (V2G) may contribute, investigation into appropriate network and SAPS configurations and control system requirements, and how SAPS may impact the value of customer DER through increased curtailment.
Recommendation 6 National potential for resilience-based SAPS study	An in-depth study should be conducted aimed at identifying the potential for resilience-based SAPS across Australia, including in areas prone to natural hazard events, such as cyclones, major storms and/or bushfires, to identify total costs and benefits of a SAPS-based approach. The study would consider climate change scenarios.
Recommendation 7 Network resilience measures feasibility study	A study should be undertaken which identifies a broader suite of resilience measures (not necessarily related to DER) and the relevant applications (i.e. where business cases are likely to be positive). This may include consideration of undergrounding, automation to restore supply, and diversification of feeder locations (where more than one feeder supplies an area) to provide a more holistic framework of measures for managing network resilience.

[12] See https://horizonpower.com.au/our-community/projects/onslow-distributed-energy-resource-der-project/#:~:text=Horizon%20Power%20will%20start%20to,DER%20on%20Horizon%20Power's%20network.

Glossary

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APRA	Australian Prudential Regulation Authority
ARR	Annual Revenue Requirement
Capex	Capital Expenditure
CESS	Capital Efficiency Sharing Scheme
DER	Distributed Energy Resource
DNSP	Distribution Network Service Provider
EBSS	Efficiency Benefit Sharing Scheme
ESCI	Energy Sector Climate Information
ENA	Energy Networks Australia
ENSMS	Electricity Network Safety Management System
ESV	Essential Services Commission
EV	Electric Vehicle
GSL	Guaranteed Service Levels
HV	High Voltage
IEEE	Institute of Electrical and Electronics Engineers
Km	Kilometre
kW	Kilowatts
MED	Major Event Day
MW	Mega Watts
MWh	Mega Watts Hour
NECF	National Energy Customer Framework
NEM	National Electricity Market
NEO	National Electricity Objective
NER	National Electricity Rules
NERL	National Energy Retail Law
NERR	National Energy Retail Rules
NSP	Network Service Providers

NSW	New South Wales
PWC	Power Water Corporation
RAES	Remote Area Energy Supply
REFCL	Rapid Earth Fault Current Limiter
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SAPS	Stand-alone Power Systems
STPIS	Service Target Performance Incentive Scheme
USE	Unserved Energy
VCR	Value of Customer Reliability
V2G	Vehicle to Grid
WALDO	Wide Area Long Duration Outages

Definitions

Term	Definition
AS 5577-2013	Australian Standard governing Electricity Network Management and Safety Systems
Individual Power Systems	Refers to a subset of stand-alone power systems that supply electricity to a single customer
Islandable Power System	Refers to a power system that is connected to an electricity network but is capable of being islanded and of operating independently from the electricity network
Materiality	In reference to the application of clause 6.6.1 of the NER, materiality refers to a DNSP incurring materially higher or materially lower costs if the change in costs (as opposed to the revenue impact) that the DNSP has incurred and is likely to incur in any regulatory year of a regulatory control period, as a result of that event, exceeds 1% of the annual revenue requirement for the DNSP for that regulatory year
Natural Hazard Event	Refers to naturally occurring physical phenomena caused by rapid or slow onset of events, including bushfires, floods, storms, cyclones, heatwaves, earthquakes and tsunamis that disrupt and cause loss in society
Network Resilience	The capacity of networks to prepare for, absorb and recover from natural hazard events, and to learn, adapt and transform in ways that enhance these capacities in the face of future events
Stand-Alone Power System	An electricity supply arrangement which does not rely on physical connection to the national grid. The term encompasses both large SAPS, which supply electricity to multiple customers, and individual power systems, which relate only to single customers

1. Introduction

Australia's electricity networks operate across diverse regions spanning harsh climates which are particularly susceptible to natural hazard events such as extreme heat waves, bushfires, major storms, cyclones and flash flooding. These types of events can have damaging effects on electricity network infrastructure resulting in long duration localised outages.

Increasing temperatures and changing rainfall patterns in Australia from anthropogenic climate change is increasing the risk of extreme natural hazard events.[13]

The capacity for electricity networks to resist and quickly recover from natural hazard events is referred to as resilience. Given that the severity and frequency of extreme weather events is likely to increase over coming years, and having witnessed the impact of recent severe storm events[14] as well as the impact of the 2019-20 bushfires in Queensland, New South Wales (NSW) and Victoria, network resilience is an issue that is likely to grow in importance over the coming years.

This report seeks to explore the potential for renewable based stand-alone power systems (SAPS) to improve electricity networks' resilience to natural hazard events and aims to create awareness of issues and gaps in the regulatory framework, which may act as a barrier to the uptake of SAPS for network resilience purposes. As part of this report, we have sought to consider the associated costs and benefits of removing a long high voltage (HV) feeder under different scenarios. Such as where the HV feeder supports a small town, clusters of residential and light commercial customers, and individual customer(s) when applying a natural hazard event probability.

While this report predominately focuses on how SAPS can enhance network resilience to natural hazard events, it is important to note that SAPS can also be adversely impacted from such events. Consequently, future work should consider and examine the risks posed to SAPS from natural hazard events to ensure that the implementation of SAPS delivers better customer and community outcomes.

Future work may also consider how the AEMC proposed SAPS framework (not considered in the modelling here) may apply.

1.1. Purpose and objectives

This report aims to assess whether an increase in the frequency of natural hazard events (such as bushfires and major storms) under climate change projections improves the business case for network investment in SAPS, using three hypothetical case studies. It is envisaged that the case studies examined will provide network service providers (NSPs) with guidance on the circumstances and parameters likely to influence business case outcomes for SAPS.

Our review of current regulatory and consumer protection settings is aimed at identifying potential gaps and barriers to NSP investment in SAPS for network resilience purposes, and considers whether a rule change or changes to Australian Energy Regulator (AER)/NSP practices are required to support the adoption of SAPS where a positive business case can be identified.

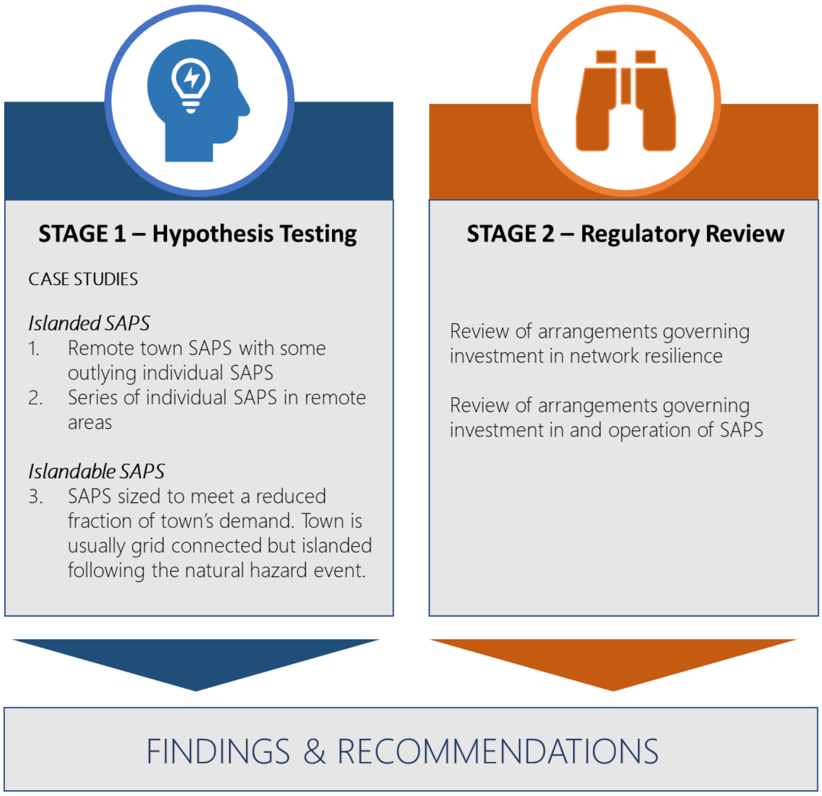
[13] BOM, 2018, 'State of the Climate 2018' http://www.bom.gov.au/state-of-the-climate/State-of-the-Climate-2018.pdf
[14] https://www.disasterassist.gov.au/find-a-disaster/australian-disasters

1.2. Approach

We have conducted our investigation into the potential for SAPS to enhance network resilience over two stages, with the outcomes from these investigations used to develop recommendations aimed at improving the uptake of SAPS for resilience purposes, as highlighted by Figure 2.

In Stage 1 of our analysis, we considered three hypothetical case studies considered likely to be amenable to SAPS under increased frequency of natural hazard events. In Stage 2, we examined relevant regulatory and consumer arrangements governing SAPS and resilience to determine whether these arrangements acted as a barrier to investment in network resilience.

Figure 2 – Overview of approach



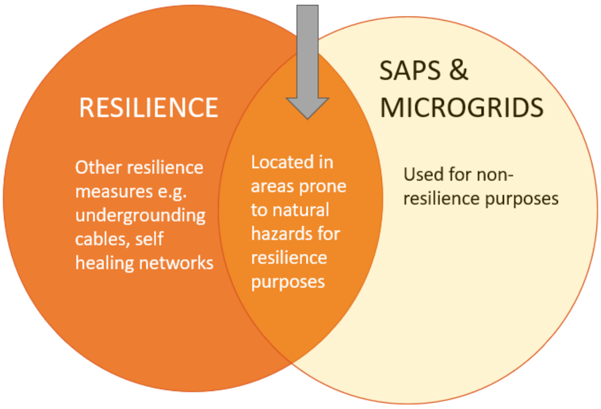
In preparing this study we have engaged with a Reference Group comprised of network business representatives, customer representatives, and a community member from Mallacoota (a town deeply impacted by recent bushfires) as well as ARENA and Energy Networks Association. The Reference Group has provided input into shaping the case studies and in developing the findings set out in this report. A list of Reference Group members is provided in Appendix A.

1.3. Scope

This review is not aimed at assessing the impact of climate change projections on network resilience, nor at assessing the effectiveness of resilience measures broadly available for NSPs to utilise. Rather, it is focused, as highlighted by Figure 3, on examining whether exposure to an increased frequency in natural hazards (such as bushfires or storms) has the potential to materially improve the business case for implementing a SAPS solution to enhance network resilience.

The regulatory framework for SAPS, and the integration of DER more broadly, is an area which is still evolving. Consequently, our review of regulatory settings for SAPS provides a summary of the work being progressed by the Australian Energy Market Commission (AEMC) and the AER, while our regulatory review of resilience seeks to examine how resilience is considered under the existing regulatory framework.

Figure 3 - Report scope and focus of modelling analysis



While we recognise that customer engagement will be a key issue in determining the appropriateness of transitioning customers to a SAPS solution and in the preparation of business cases, this issue is beyond the scope of this review.

1.4. Report Structure

Our report is structured around the following themes:

- *Section 2: Context* – outlines key drivers for undertaking this study.
- *Section 3: Case studies* – outlines key findings from our modelling results aimed at assessing the feasibility of investment in SAPS under three different case studies.
- *Section 4: Regulatory review* – provides a review of current regulatory arrangements governing network resilience and highlights key implications from current arrangements which may need to be addressed to improve network resilience outcomes.
- *Section 5: Recommendations* – outlines key recommendations aimed at enhancing network resilience.

2. Context

This section sets out some of the background and key drivers for this review.

2.1. What is network resilience?

There are numerous definitions of resilience. For this review we have adopted the Australian Natural Disaster Resilience Index (Bushfire and Natural Hazards CRC) definition of resilience which is:[15]

> *"The capacity of communities to* ***prepare*** *for,* ***absorb*** *and* ***recover*** *from natural hazard events and to learn, adapt and transform in ways that enhance these capacities in the face of future events."*

Network resilience is accordingly considered to consist of three main elements:

1) Measures to avoid and mitigate the impact from the natural hazard event through proactive investment
2) Measures that enable network businesses to absorb the impact of natural hazard events and provide for short-term emergency response
3) Measures which enable recovery over the longer term

Distinguishing between natural hazard events and natural disaster events

The terms natural hazard event and natural disaster event are terms that are often used interchangeably to mean any natural hazard event – such as floods, fires, storms, tsunamis, and cyclones – which have the potential to disrupt and cause damage to society. However, a key point of difference between the two terms is that a natural hazard can occur but not result in a natural disaster event, with natural disasters considered to be the extreme form of a natural hazard event.[16]

Throughout this study we have adopted the term natural hazard event rather than natural disaster to allow for a broader assessment of climate-related network resilience, and to avoid focusing on a narrow subset of natural hazard impacts.

[15] Parsons, M., Reeve, I., McGregor, J., Marshall, G., Stayner, R, McNeill, J., Hastings, P., Glavac, S. & Morley, P. (2020) *The Australian Natural Disaster Resilience Index: Volume I – State of Disaster Resilience Report*, Melbourne: Bushfire and Natural Hazards CRC, p 3.
[16] Parsons, M., Reeve, I., McGregor, J., Marshall, G., Stayner, R, McNeill, J., Hastings, P., Glavac, S. & Morley, P. (2020) *The Australian Natural Disaster Resilience Index: Volume I – State of Disaster Resilience Report*, Melbourne: Bushfire and Natural Hazards CRC.

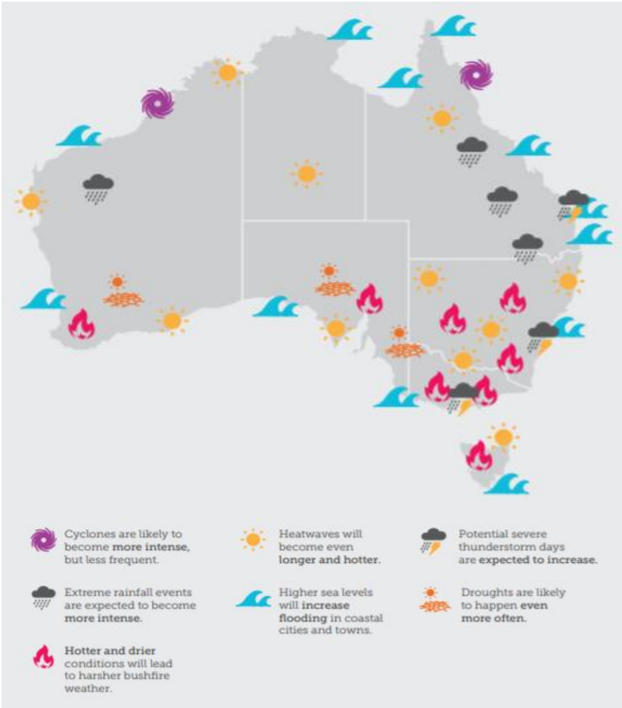
2.2. Why is resilience growing in importance?

Networks' exposure to extreme weather events is increasing

Data from the Climate Council of Australia indicates that the intensity and frequency of extreme weather events is likely to increase over the coming years with:

- Cyclones likely to become more intense but less frequent
- Extreme rainfall events likely to become more intense
- Hotter and drier conditions likely to lead to harsher bushfire weather
- Heatwaves becoming hotter and longer
- Higher sea levels increasing the risk of flooding in coastal cities and towns
- Potential severe thunderstorm days expected to increase
- Droughts expected to occur more often

Figure 4 - Impact of climate change on extreme weather events



Source: Climate Council of Australia 2019 Dangerous Summer: Escalating Bushfire, Heat and Drought Risk, p. 6.

Natural hazard events can affect electricity network infrastructure in the following ways:

- Strong winds may directly bring down overhead lines and poles, while falling trees and tree debris may also cause significant damage to overhead lines and lift underground cables.
- Flooding may inundate substations and underground assets, rendering them unusable.
- Bushfires not only burn through above-ground network assets, but electricity networks are potentially a source of ignition for bushfires, particularly on extreme fire weather days.[17]

All the above have the potential to lead to long duration outages for customers and can affect communities' ability to absorb and recover from natural hazard events. This year alone, there have been four cost pass through applications submitted by DNSPs to date seeking to recover an additional $74 million from electricity customers for damage sustained to network infrastructure from recent bushfire and severe

[17] Miller, C., Plucinski, M., Sullivan, A., Stephenson, A., Huston, C., Charman, K., Prakash, M. & Dunstall, S., 2017. Electrically caused wildfires in Victoria, Australia are over-represented when fire danger is elevated. *Landscape and Urban Planning* 167: 267–274.

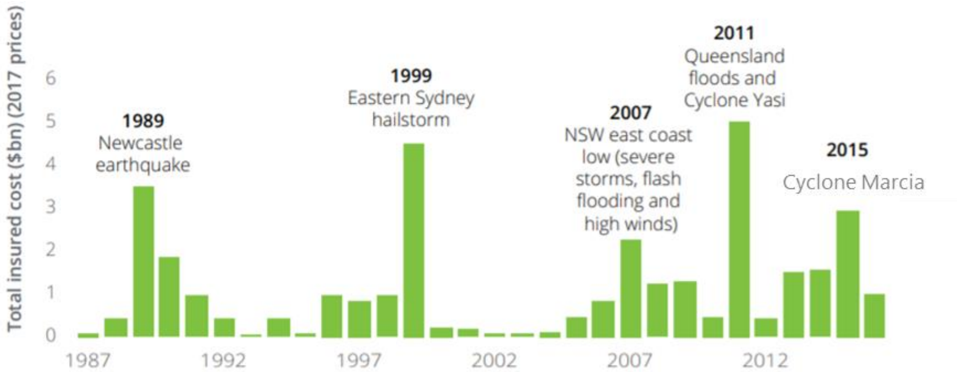
weather events.[18] However, it is important to note that this amount reflects the eligible pass through amount rather than the actual cost impact from these events, which is significantly higher at $125 million.[19]

Natural disaster events impose significant costs to consumers and the economy

Natural disasters impact infrastructure, essential services and communities and can cost billions of dollars. The total economic cost of natural disasters is comprised of:[20]

- *Direct tangible costs* which include emergency response efforts and damage to property and infrastructure
- *Indirect tangible costs* which include flow on effects to businesses and networks such as network outages or disruptions to business or supply chains
- *Intangible costs* which capture death, injury and impacts on health and wellbeing, employment and community connectedness. Intangible costs are estimated to be as great, or greater than, tangible costs, however they are hard to price

In a paper prepared by Deloitte Access Economics for the Australian Business Round Table for Disaster Resilience and Safer Communities, it was estimated that natural disasters cost Australians over $13 billion every year. As the frequency and intensity of natural disaster event increases, these costs are expected to escalate over the coming years.



Source: Deloitte Access Economics, 2017, *'Building resilience to natural disasters in our states and territories,' p 19* and Insurance Council Australia, 2017.

Findings from the National Institute of Building Science in the United States indicate that the cost savings from investing in risk mitigation could result in savings amounting to a ratio of 1:4.[21] This finding is

[18] See Ausgrid, *Ausgrid pass through application 2019/20 storm season*, 31 July 2020, AusNet, *Cost pass through application – 2020 Summer Bushfires*, 27 May 2020, AusNet, *Cost pass through application – 500kV Transmission Line Tower Collapse*, July 2020, Endeavour Energy, *Cost pass through application: 2019-20 Bushfire disaster event*, 31 August 2020.

[19] This amount includes the total cost impacts stated in AusNet, *Cost pass through application – 2020 Summer Bushfires*, 27 May 2020,p 5; AusNet, *Cost pass through application – 500kV Transmission Line Tower Collapse*, July 2020, p 3, and STPIS impacts noted in Ausgrid, *Ausgrid pass through application 2019/20 storm season*, 31 July 2020, p 46.

[20] Deloitte Access Economics, 2017, *'Building resilience to natural disasters in our states and territories,'* a report prepared for the Australian Business Round Table for Disaster Resilience and Safer Communities, p. 16.

[21] NIBS (National Institute of Building Sciences), 2017. *Natural Hazard Mitigation Saves: 2017 Interim Report*, Washington DC, USA, p. 344. See also https://www.nibs.org/news/381874/National-Institute-of-Building-Sciences-Issues-New-Report-on-the-Value-of-Mitigation.htm

particularly relevant to the context of electricity networks where there has been a significant increase in network businesses submitting cost pass through applications to recover costs sustained to network infrastructure from bushfires,[22] severe storms[23] and winds.[24]

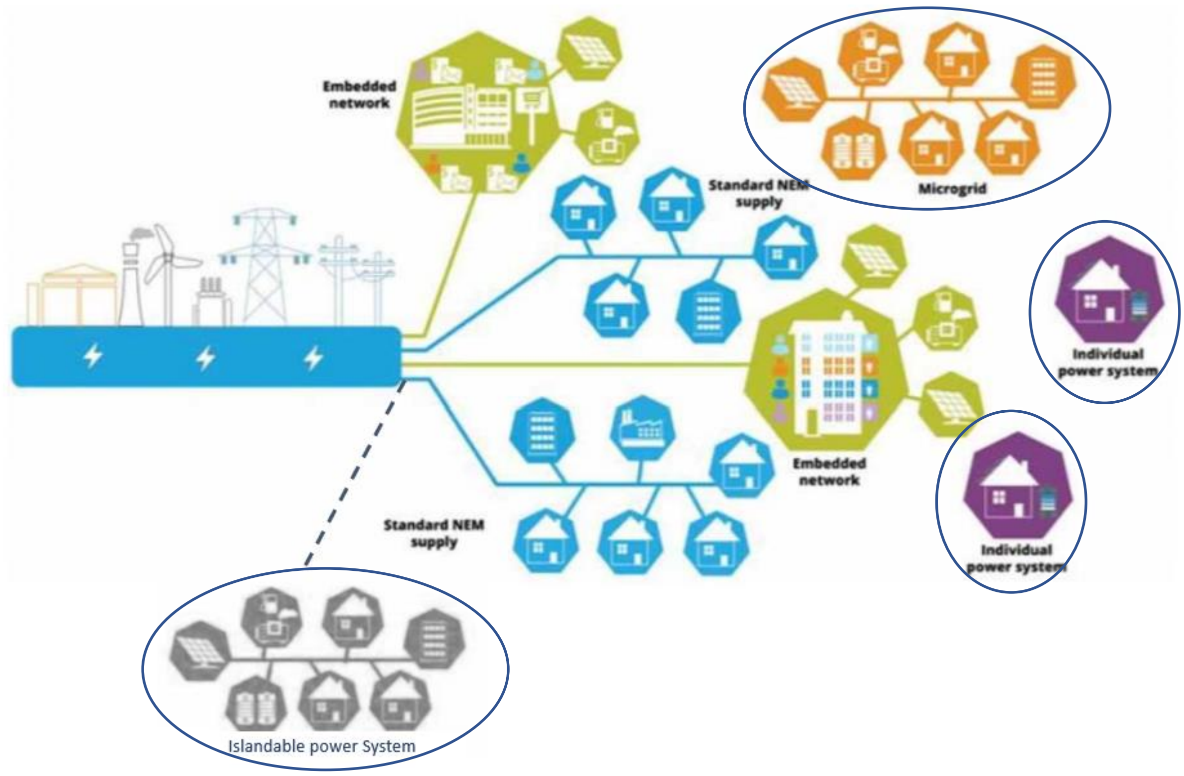
What are SAPS and how can they enhance network resilience?

A SAPS refers to an electricity supply arrangement which does not rely on a physical connection to the national grid. The term encompasses both large SAPS (microgrids), which supply electricity to multiple customers, and individual stand-alone power systems, which relate only to single customers.

Consequently, the term SAPS is quite broad and can be used to describe several different scenarios. For the purposes of this study, we have explored the potential for large SAPS and individual SAPS to enhance network resilience, as well as the use of islandable power systems – which refer to power systems that are connected to the electricity network but are capable of operating independently and in isolation from the electricity network.

Figure 5 below, illustrates the different types of SAPS considered as part of this study, and seeks to highlight how SAPS arrangements differ to standard supply arrangements and embedded networks.

Figure 5 - Overview of different electricity supply arrangements



Source: Adapted from AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, Final report, 28 May 2020, p 4.

[22] AusNet, *Cost pass through application – 2020 Summer Bushfires*, 27 May 2020 and Endeavour Energy, *Cost pass through application: 2019-20 Bushfire disaster event*, 31 August 2020.
[23] Ausgrid, *Ausgrid pass through application 2019/20 storm season*, 31 July 2020.
[24] AusNet, *Cost pass through application – 500kV Transmission Line Tower Collapse*, July 2020.

There are a number of ways in which SAPS can help to enhance network resilience, including by:

- Avoiding the costs of replacing damaged or destroyed overhead lines after a natural hazard event
- Avoiding long duration outages (to customers and/or communities)
- Providing power on a temporary basis while more substantive network repair work is undertaken following the occurrence of a natural hazard event.

They also have the potential to deliver broader benefits such as:

- Enhancing the resilience of communities located in areas prone to natural hazard events
- Reducing vegetation and reliability costs in supplying customers located in rural and remote areas
- Improving reliability for customers in rural and remote areas.[25]

[25] See Western Power's Ravensthorpe Stand-Alone Power Systems Trial for further details https://westernpower.com.au/community/news-opinion/3-in-a-row-great-southern-trial-proves-sps-great-for-country-wa/

3. Case studies

Our study evaluates the potential for a resilience-based SAPS by examining three hypothetical case studies. As theoretical case studies, they may not provide a true indication of the opportunity for resilience-based SAPS. Further the case studies present an economic perspective and importantly do not take into account financial implications of the AEMC's proposed delivery model for SAPS.

The case studies explored include:

- Case Study 1: Provision of an **isolated SAPS to a remote town** of approximately 500 customers, which is capable of supplying the township's entire demand. The township is then completely disconnected from the network.
- Case Study 2: Provision of **individual isolated SAPS** to 60 customers, which are capable of supplying the customers' entire demand. The customers are then completely disconnected from the network.
- Case Study 3: Provision of an **islandable power system to a remote town** of approximately 500 customers which is capable of supplying around 45% of the township's demand. The township is ordinarily connected to the network and only becomes islanded during an outage.

Case Study 1 and 3 examine similar scenarios, however a key point of difference between the two is that the entire town demand is supplied via the SAPS in Case Study 1, with the township completely disconnected from the network. Whereas in Case Study 3, the town remains connected to the network, with an islandable power system only partially supplying the township's total demand. Case Study 2 contemplates SAPS arrangements for individual residential customers, clusters of residential customers, and individual light commercial customers.

These case studies were chosen as representative and plausible examples of SAPS and refined through consultation with the Reference Group that was established to help inform our findings. The case studies are intended to be broadly representative of a small town in the South East of Australia at the end of a HV line, prone to bushfires. Any resulting business case would need to consider a complex range of inputs impacting a business case, such as security, reliability and resilience obligations, implications for existing and new behind the meter DER, as well as the potential risks and impacts that SAPS solutions face from natural hazard events.

Overview of modelling approach

For each of the case studies, we undertook the following steps to reach our findings:

1. Identified the net present value (NPV) of the SAPS approach as the difference between:
   - *Base case*: where the network is repaired with like-for-like after it is damaged by each natural hazard event and at the end of asset life over a 50-year period, assuming no change in probability of natural hazard events.
   - *Resilient case*: where an alternative SAPS-based approach is adopted such that customer outages can be avoided over a 50-year period, assuming no change in the probability of natural hazard events. The extent of network repair/rebuild required depends on whether the SAPS is islanded (where these costs are completely avoided) or islandable (where these costs are not avoided)

2. Identified the sensitivity of the business case to a wide range of factors which are likely to vary depending on location, including size of town, length of feeder, duration of outages after natural hazard event, battery prices, and reliability of existing feeder.
3. Identified the level of increased frequency of natural hazard events needed to make the business case net positive.
4. Reviewed relevant climate change projections to determine whether the increased frequencies determined in step 4 were plausible.

The sizing of the SAPS in Step 1 for each case study was optimised for the peak load (solar PV, generator) and average load (battery) required to be supplied based on 2020 costs, assuming that the use of diesel was minimised.[26] An additional premium was added to all individual SAPS to account for the system likely to be established outside of the customer premise requiring ground-mounting and enclosures.

The SAPS assets were also assumed to be required to be replaced several times over the 50 year modelling period depending on the individual asset lifespan. A declining cost in SAPS assets was also assumed such that the replacement cost is assumed to be lower than the initial cost of deployment.

It should be noted that the model is an economic model based on costs of systems and does not seek to provide a financial model which may need to build in costs associated with leasing or third party supply of SAPS, nor the direct financial benefit or otherwise to customers.

Key inputs and assumptions used in our case study modelling are set out in Appendix B.

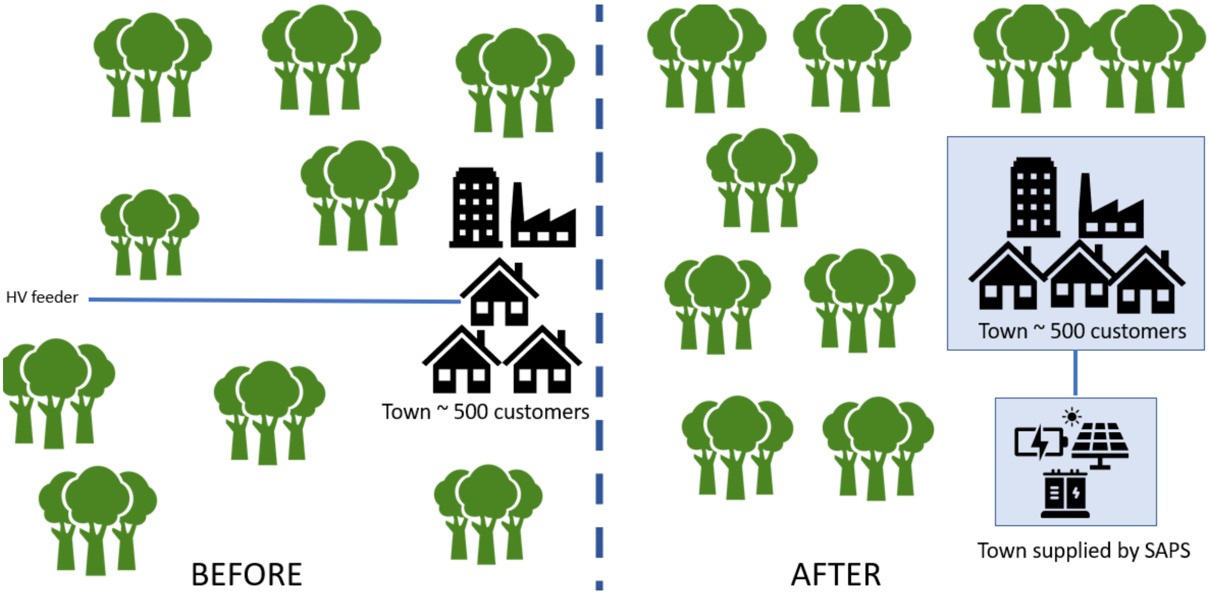
[26] While diesel generation may represent the lowest cost, especially for the smaller SAPS, a 100% diesel system was not considered. This was based on consideration of community acceptance as well as potential logistical issues supplying a town with diesel during the recovery period, including diesel fuel storage capacity and access issues for transportation of diesel fuel immediately following a natural hazard event.

Case Study 1: Isolated SAPS to a remote town

The first case study describes a remote town of approximately 500 customers provided with a large SAPS which is completed islanded from the network. Figure 6 below, shows the difference in electricity supply arrangements, prior to and following the implementation of SAPS solutions to supply the town and individual customers.

Further details are set out below.

Figure 6 - Isolated SAPS to a remote town



Town attributes

- Small, remote town (~500 customers) located at the end of a 75km 22kV HV line
- Town peak demand of 1,500 MVA
- 95% of the HV feeder travels through a heavily forested region that is prone to bushfires (4% probability that a major bushfire will destroy the line in forested areas in any given year)
- There are no individual customers in the countryside that also rely on the HV feeder.

Proposed SAPS attributes

- Town converted into a SAPS (6MW solar, 10MWh battery, 1.5MW diesel generator)
- Town SAPS includes 0.5MW of embedded solar
- Town LV network is retained for use by SAPS
- Permanently islanded and the HV feeder is decommissioned.

Benefits (standard)

- Avoided wholesale energy costs as end-user electricity will be supplied locally by the SAPS
- Cost of replacing the line when it reaches end of life can be avoided if it is decommissioned instead
- The line can no longer be damaged, so cost of repairs after minor damage are avoided

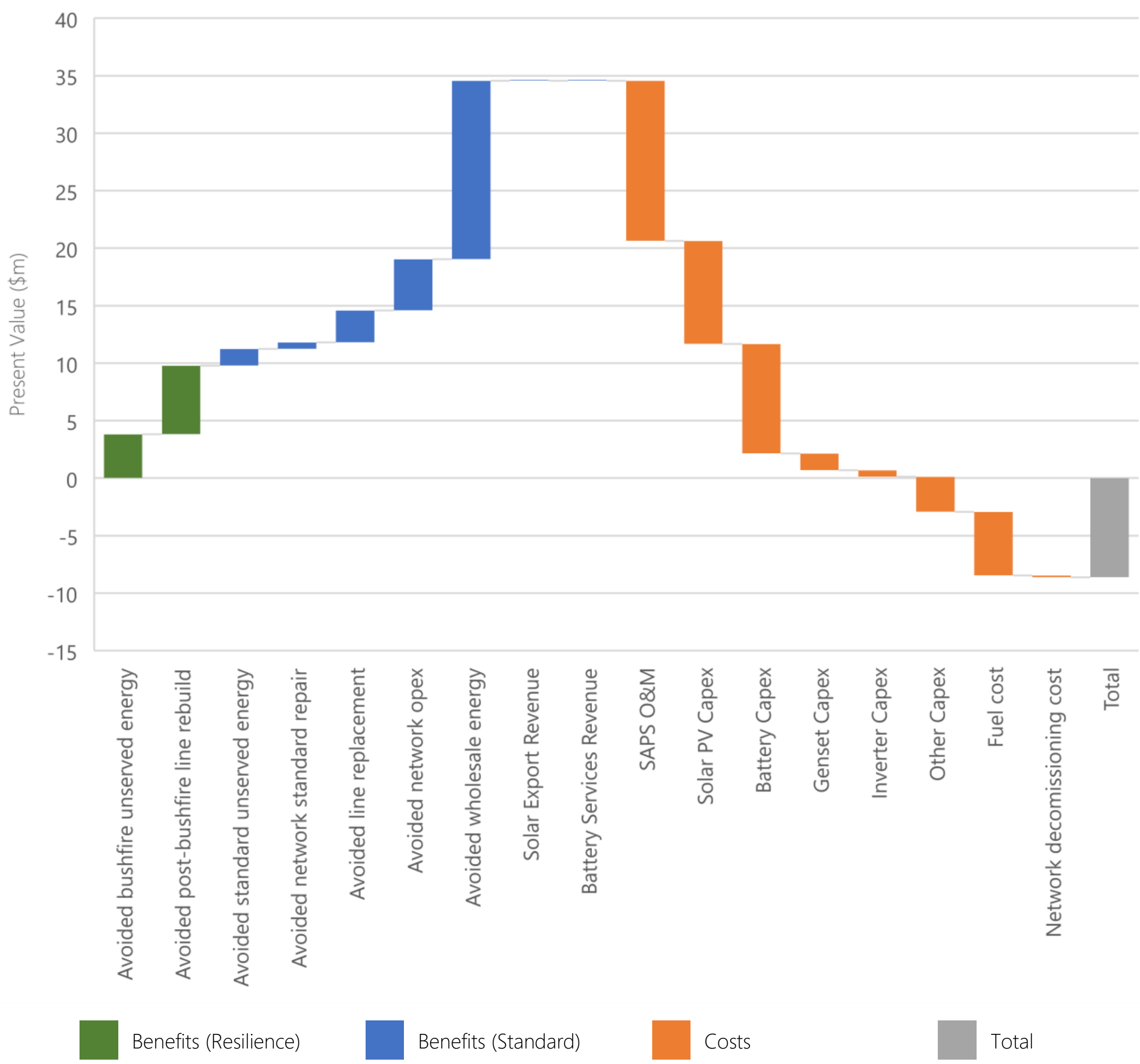
- The network no longer needs to maintain the line, which includes the cost of vegetation management
- Customers experience fewer outages associated with standard outages (unrelated to natural hazard events).

Benefits (resilience)

- Cost of replacing the line after a large bushfire are avoided
- Customers no longer experience long duration outages when the line is damaged/destroyed during a natural hazard event.

Modelling results for Case Study 1 show a negative net present value of $8.6m over a 50 year period with the contribution of individual benefits and costs to the overall business case shown in Figure 7.

Figure 7 – Benefits and costs of Case Study 1



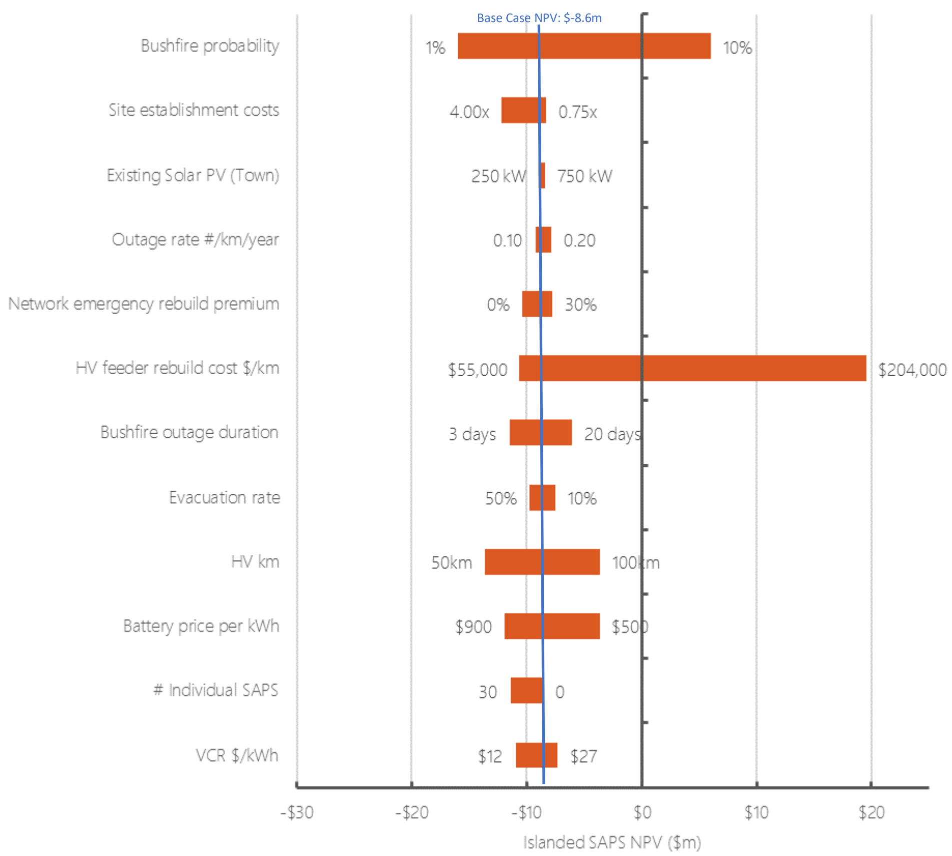
The largest benefit in this scenario is avoided wholesale energy costs as end-user electricity will be supplied locally by the SAPS. This benefit offsets a portion of the cost of installing and operating the SAPS but is not sufficient to justify the transition away from a centralised grid.

There are several other benefits that are unique to the location being considered in this case study. These benefits are related to the reliability and cost of retaining the long HV feeder that supplies the town and surrounding customers. The main avoided costs are:

- The cost of replacing the line when it reaches end of life if it is decommissioned instead
- The cost of repairs after minor damage and replacement after a large bushfire as the line can no longer be damaged
- Customers no longer experience outages when the line is down
- Operating costs such as keeping vegetation clear of the line as the network no longer needs to maintain the line.

Sensitivity testing of a selection of the most significant inputs shows a positive NPV may be possible in some circumstances. The high end of estimates for bushfire probability and HV feeder rebuild costs may result in a positive NPV. A bushfire probability of 7.6% will result in a small positive NPV without changing any of the other inputs. A combination of multiple other assumptions may also result in a positive NPV. The NPV range for a selection of key assumptions, for both negative and positive shifts away from the base case assumptions, is shown in Figure 8.

Figure 8 – Sensitivity analysis of Case Study 1



Bushfire probability

The probability of a bushfire occurring in any given location and in any given year is dependent on the probability of high danger fire weather, of ignition, and of the bushfire impacting the location.

Probability of high danger fire weather

The probability of high danger fire weather is captured in the Forest Fire Danger Index (FFDI). This index is mainly a function of ambient (wind, air temperature and humidity) and drought conditions at the time of fire. The additive combination of these two conditions have been shown to have a marked threshold effect on large-fire ignition and total area burned in areas of New South Wales.[27]

Probability of ignition

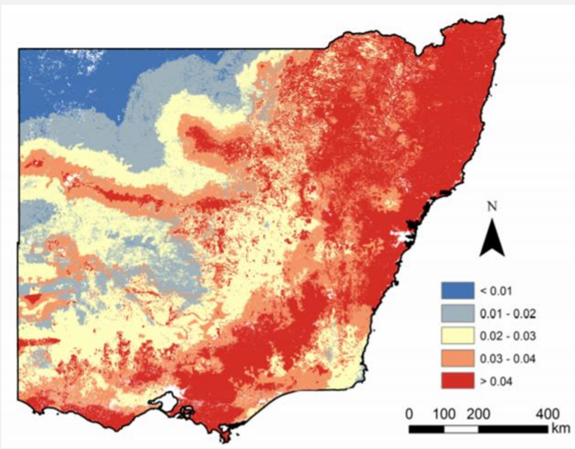
The probability of a bushfire igniting is in part dependent on the local weather on the day of ignition as well as more general measures of weather, such as the Indian Ocean dipole and Southern Annular Mode. The risk of bushfire outbreaks is increasing due to anthropogenic factors like aging electricity infrastructure. For example, an inquiry report following the 2009 Black Saturday bushfires estimated that 200 fires per year are started in Victoria due to the ageing electricity grid, while a 2017 study found that fires sparked by electricity failures are more prevalent during elevated fire risk and tend to burn larger, making them worse than fires due to other causes.[28]

Probability of a bushfire impacting a certain location

The probability that a bushfire will impact a given location is dependent on local combinations of vegetation, terrain and weather as well as anthropogenic variables.

Current bushfire probability

There are relatively few studies attempting to assign a probability to a bushfire occurring in one particular location, given the uncertainty of the input variables above. Probabilities for larger regions (such as an entire state or region) are more common but are not applicable to our case studies. A 2015 study provides an estimate by region, assigning a maximum of 4% in any given region.



Predicted probability of bushfire occurrence in south-eastern Australia[29]

[27] R. A. Bradstock, J. S. Cohn, A. M. Gill, M. Bedward and C. Lucas, Prediction of the probability of large fires in the Sydney region of south-eastern Australia using fire weather, December 2009.
[28] G. J. van Oldenborgh et al., Attribution of the Australian bushfire risk to anthropogenic climate change, March 2020
[29] Y. Zhang, S. Lim, J.J. Sharples, Development of spatial models for bushfire occurrence in South-Eastern Australia, 2015

Bushfire probability under climate change

Studies into how climate change will impact bushfire probability tend to focus on how the frequency of high fire danger weather (FFDI and drought conditions) is likely to increase, without necessarily stating an increased probability of bushfires. In 2007, a CSIRO study[30] used to inform the Garnaut Climate Change review[31] found an increase of between 5% and 300% of extreme fire weather days by 2050. A more recent (2020) study has suggested that conditions experienced over the 2019/20 level will be at least four times more likely with a 2°C temperature rise, compared with 1900. Due to the model limitations, this is likely an underestimate.[32]

It is therefore considered plausible, assuming there is currently around 4% probability of a bushfire occurring in any given year in bushfire prone areas, that this could more than double in the medium term future such that the business cases presented would become net positive.

30 Lucas, C., Hennessey K., ucas, C., Hennessey, K., Mills, G. & Bathols, J. 2007, *Bushfire Weather in Southeast Australia: Recent trends and projected climate change impacts*, consultancy report prepared for the Climate Institute of Australia.

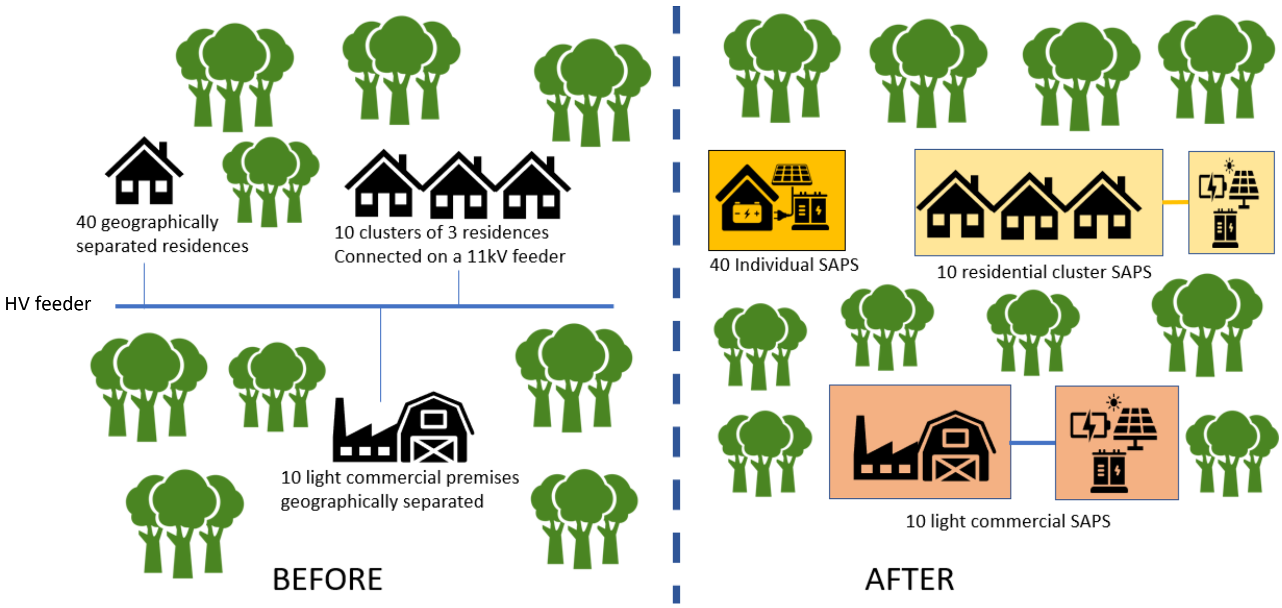
31 Garnaut, R., Garnaut Climate Change Review, 2008

32 van Oldenborgh, G. J., Krikken, F., Lewis, S., Leach, N. J., Lehner, F., Saunders, K. R., van Weele, M., Haustein, K., Li, S., Wallom, D., Sparrow, S., Arrighi, J., Singh, R. P., van Aalst, M. K., Philip, S. Y., Vautard, R., and Otto, F. E. L.: *Attribution of the Australian bushfire risk to anthropogenic climate change*, Nat. Hazards Earth Syst. Sci. Discuss., https://doi.org/10.5194/nhess-2020-69, in review, 2020..

Case Study 2: Individual Isolated SAPS

The second case study describes a remote location with geographically dispersed customers which are provided with their own individual SAPS (as opposed to connected via a large SAPS installation). Figure 9 below, provides a comparison of electricity supply arrangements before and after implementing individual SAPS solutions in heavily forested area. As shown by Figure 9, this case study explores the feasibility of implementing three different kinds of SAPS arrangements for individual customers, residential customers, and light commercial customers. Further details are set out below.

Figure 9 - Individual isolated SAPS



Town attributes

- Geographically separated customers within a low population region including:
    - Residential Individual: 40 geographically separated residential premises
    - Residential Cluster: 10 clusters of three residential premises connected by a small LV network
    - Light Commercial: 10 geographically separated light commercial premises.
- Supplied via a 75km 22kV HV line
- 95% of the HV feeder travels through a heavily forested region that is prone to bushfires (4% probability that a major bushfire will destroy the line in forested areas in any given year).

Proposed SAPS attributes

- Individual SAPS:
    - 40 individual residential SAPS (20kW solar, 33kWh battery, 5kW diesel generator)
    - 10 residential cluster SAPS (60kW solar, 100kWh battery, 15kW diesel generator) connected by a small LV network

  - 10 light commercial SAPS (100kW solar, 166kWh battery, 25kW diesel generator)
  - Assumes no existing customer owned DER
- HV feeder can be decommissioned.

Benefits (standard)

- Avoided wholesale energy costs as end-user electricity will be supplied locally by the SAPS
- Cost of replacing the line when it reaches end of life can be avoided if it is decommissioned instead
- The line can no longer be damaged, so cost of repairs after minor damage are avoided
- The network no longer needs to maintain the line, which includes the cost of keeping vegetation clear of the line
- Customers experience fewer outages associated with standard outages (unrelated to natural hazard events).

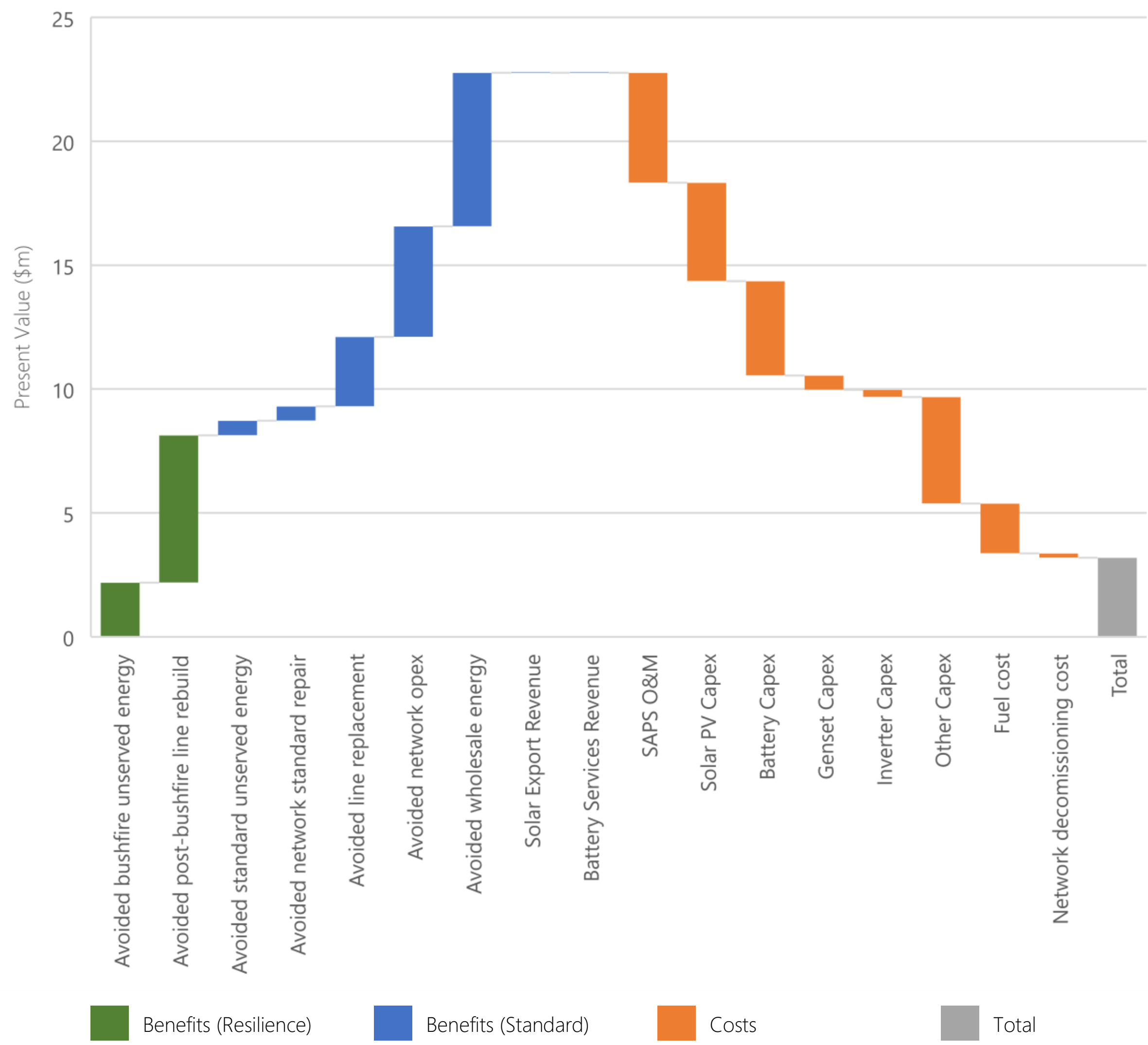
Benefits (resilience)

- Cost of replacing the line after a large bushfire are avoided
- Customers no longer experience long duration outages when the line is damaged/destroyed during a natural hazard event.

Case Study 2 has a positive net present value of $3.2M. The improved business case (compared to Case Study 1) is due to the lower demand associated with the individual SAPS (and therefore capital costs) delivering the same network benefits.

The contribution of individual benefits and costs to the NPV is shown in Figure 10.

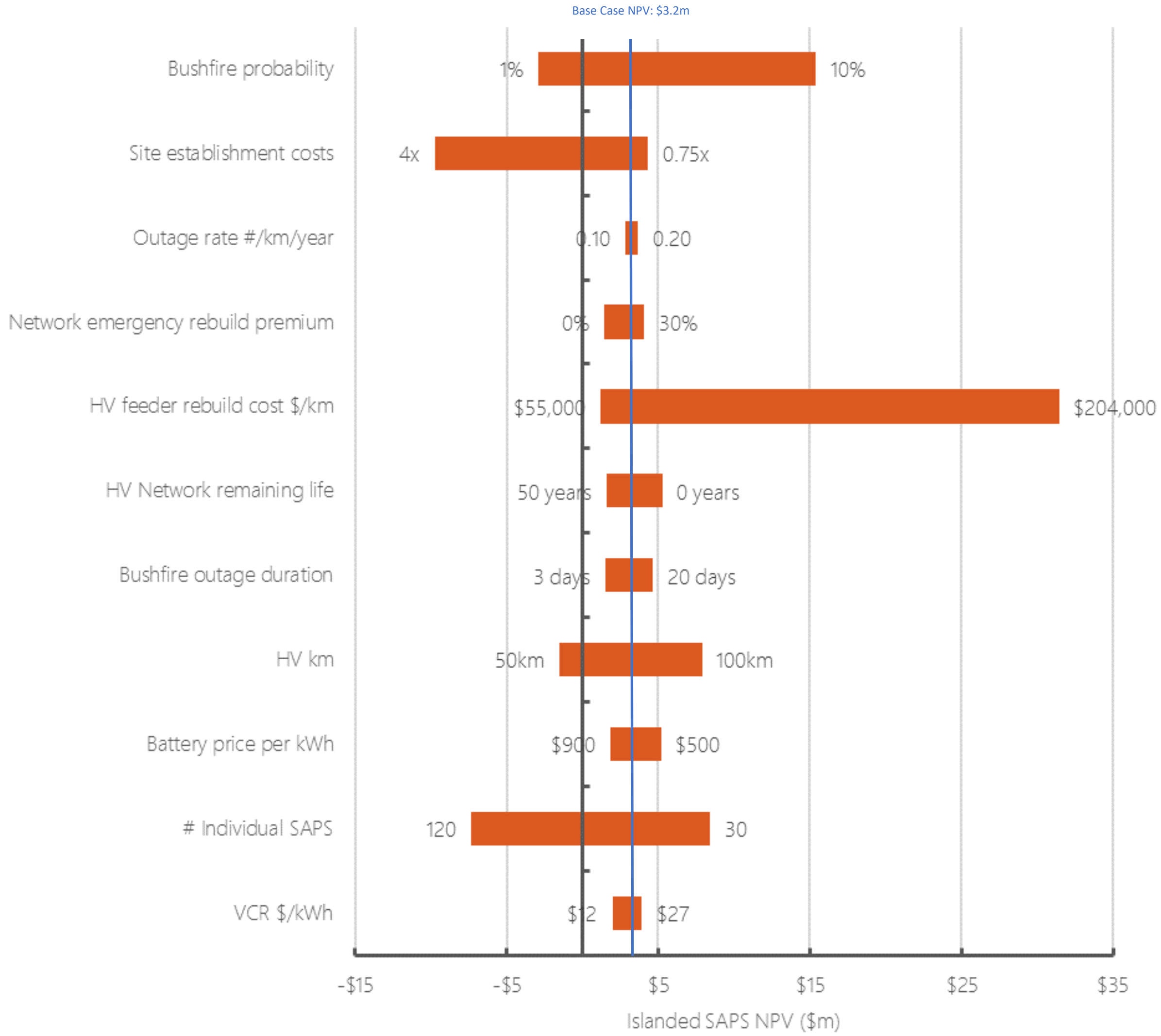
Figure 10 - Benefits and costs of Case Study 2



Compared to Case Study 1, avoided wholesale energy purchases make up a smaller share of the benefits. This is because the total load supplied by the combined SAPS is lower, but this also lowers the cost of the SAPS which scale closely with load. The network benefits such as avoided network maintenance, repair and replacement benefits, are independent of the load in the regions and so are obtained at a lower cost than in Case Study 1.

Sensitivity testing of a selection of the most significant inputs shows positive NPV results sustained for a number of permutations, consistent with some network businesses already proposing individual SAPS. As is the case in Case Study 1, an increased bushfire frequency under climate change projections will make the business case more positive.

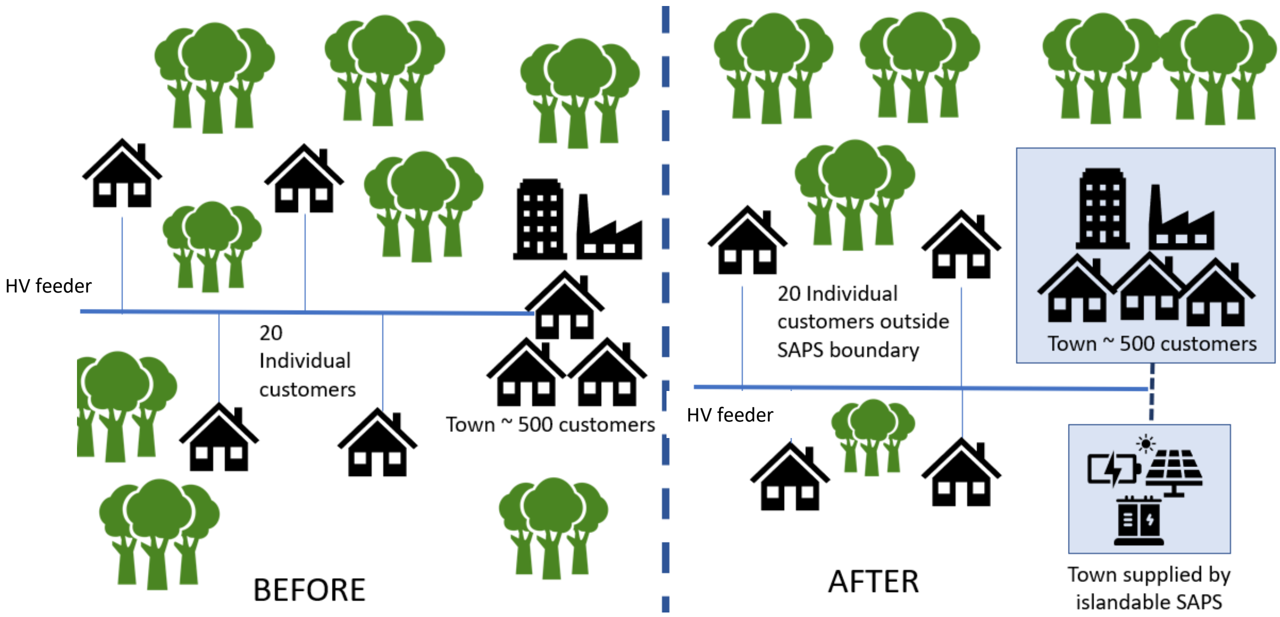
Figure 11 - Sensitivity analysis of Case Study 2



Case Study 3: Islandable power system to a remote town

The third case study describes the same remote town with a population of 500 as per Case Study 1. However, in this case study, the town is provisioned with a significantly smaller power system intended to be used in islanded mode only when an outage occurs (either a standard outage or as a result of a natural hazard event). For the remainder of the time, the solar PV and the battery system within the SAPS is used for self-consumption and export to the grid, deriving benefits. The diesel generator is only used during long duration outages.

Figure 12 - Islandable power system to a remote town



Town attributes

- Small, remote town (~500 customers) located at the end of a 75km 22kV HV line
- Town peak demand of 1,500 MVA
- 95% of the HV feeder travels through a heavily forested region that is prone to bushfires (4% probability that a major bushfire will destroy the line in forested areas in any given year)
- There are no individual customers in the countryside that rely on the HV feeder.

Proposed SAPS attributes

- All customers remain grid connected
- In a disaster situation, 30% of the town load is eliminated due to evacuations or business shutdowns
- 45% of the pre-evacuation town load is islandable during an outage (either standard or bushfire related) equating to 64% of the town's load after evacuation
- Islandable SAPS (2.7MW solar, 4.5MWh battery, 0.7MW diesel generator)
- Islandable SAPS includes 0.5MW of existing customer owned solar

- Individual customers outside the township (not included in base case but considered in sensitivity testing) and therefore beyond the SAPS boundary are not islandable (and experience outage when HV line is out)
- Solar and batteries operate 100% of time to optimise value (not just during outages).

Benefits (standard)

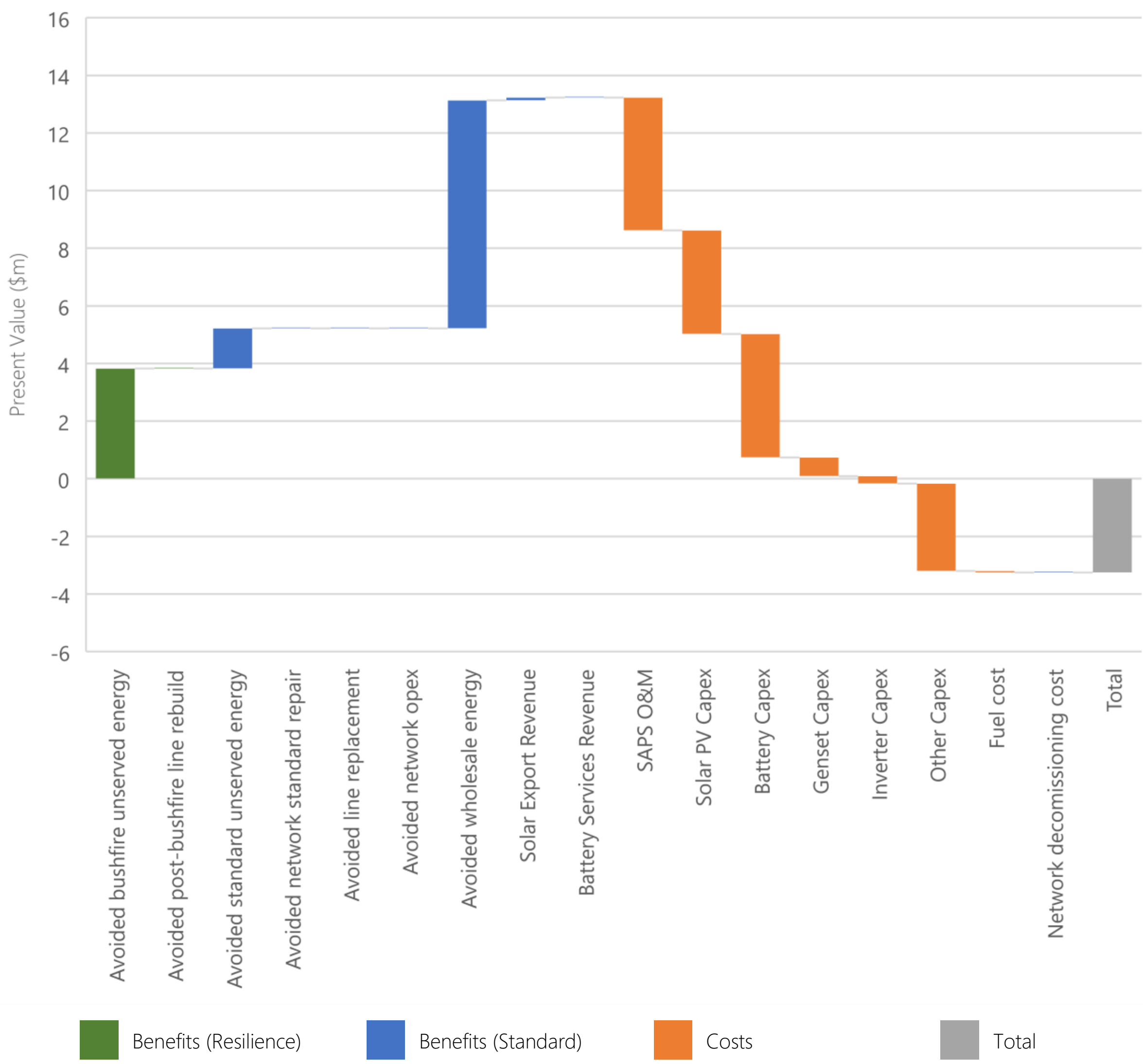
- Avoided wholesale energy costs as end-user electricity will be supplied locally by SAPS
- Solar exports (which would otherwise have been spilled in Case Study 1 due to solar being oversized)
- Customers experience fewer outages associated with standard outages (un-related to natural disaster events).

Benefits (resilience)

- At least part of the town's load is supplied during long duration outages when the line is damaged/destroyed during a bushfire,

The business case for the islandable SAPS has a negative net present value of -$3.3M. While the islandable SAPS is lower cost than the islanded SAPS in Case Study 1, it is not able to realise the benefits of avoided network rebuilds and maintenance. The contribution of individual benefits and costs to the NPV for this case study is shown in Figure 13.

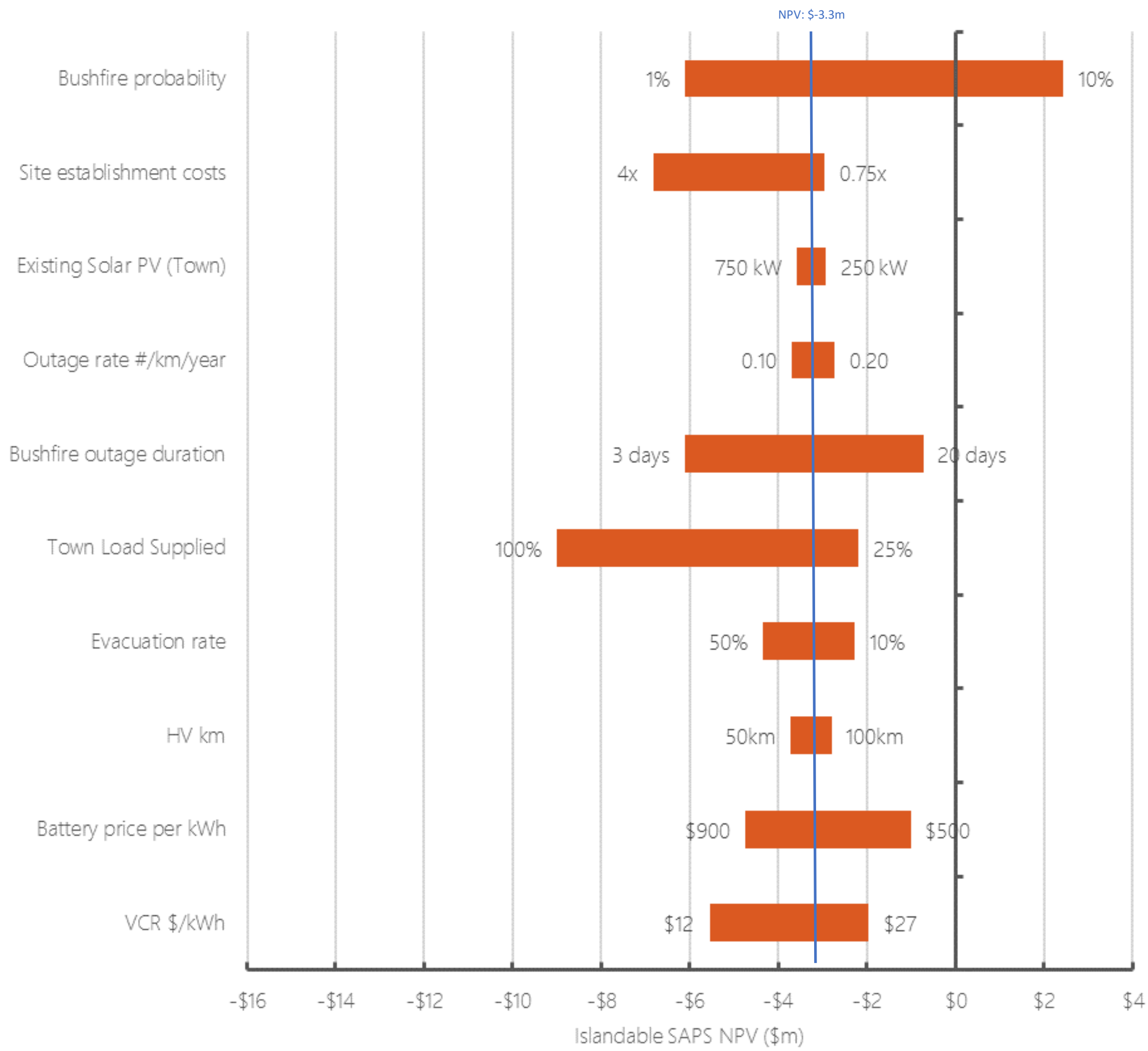
Figure 13 - Benefits and costs of Case Study 3



In Case Study 3, the islandable SAPS produces the vast majority of benefits from displacing wholesale energy purchases by the town. Very minor benefits result from solar export revenue as the SAPS is undersized relative to normal loads in the town, so there is usually no excess solar that can be exported to other customers via the centralised grid. The revenue from battery services, such as revenue from providing FCAS services, is considered a benefit. However, it is not clear how these benefits could be realised given the small and fringe nature of the SAPS.

Sensitivity testing of the business case against various input parameters is shown in Figure 14.

Figure 14 - Sensitivity analysis of Case Study 3



The case study has a positive NPV when the bushfire event probability is 7.4%.

The sensitivity test of the percentage of town load supplied includes a 100% option. This results in a SAPS with the same size as Case Study 1. However, it should be noted that a 100% islandable system is not the same as an isolated SAPS (case 3 versus case 1). In addition, if an islandable system is used as a transition measure, the system would need significant changes in order to be a permanent, town sized, SAPS.

The sensitivity to the existing customer DER is somewhat counterintuitive. The more existing solar, the worse the overall business case. This is because any additional solar attributed to the SAPS derives benefits from self consumption and export, in excess of the cost, which are counted in the business case. While existing solar lowers the cost of the SAPS compared to no existing solar, it does not derive any additional benefits.

3.1. Key Findings

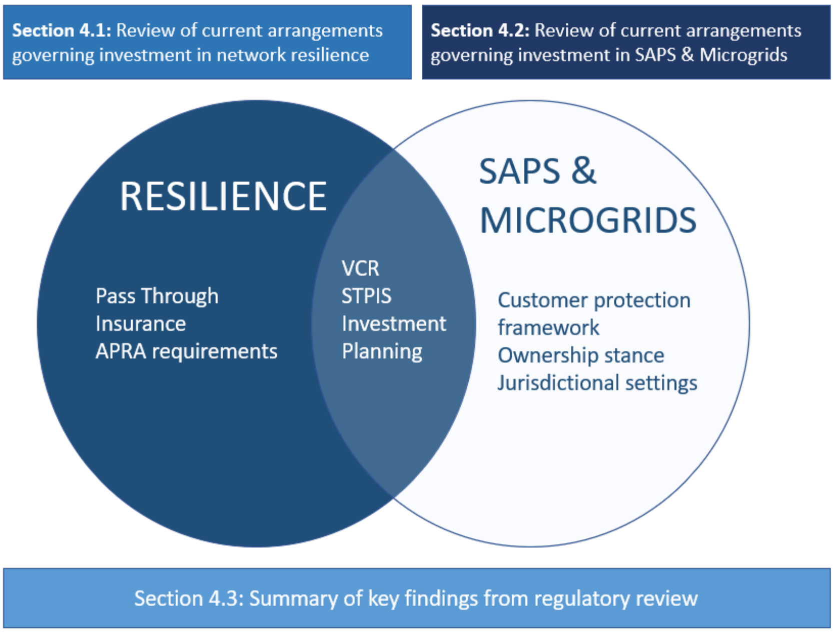
The key findings from the modelling of the case studies are:

1. The business case for islanding remote towns appears to be negative for a HV feeder, based on a 4% probability that a major natural hazard event will impact a town in any given year. This suggests that only remote, small towns with existing unreliable feeders that are nearing the end of their useful life would justify an islanded SAPS from an economic perspective.
2. The business case for an islandable remote town is also likely to be generally negative, even where only a small number of facilities are supplied when islanded. Although the cost of the system is less than for a fully islanded town, the benefits are limited as the feeder must still be maintained.
3. If the probability of a major natural hazard event impacting a town in any given year increases to 8% or more, then there is likely to be a compelling business case for provisioning some remote towns with resilience-based SAPS (either islanded or islandable). Climate change projections suggest that it is plausible that the probability of a bushfire event impacting a town in a bushfire prone area will increase beyond 8% before 2050.
4. There may be a potential implementation mechanism whereby a town may be provisioned with an islandable SAPS and then transitioned to an islanded SAPS at the end of the network's asset life or after the network asset is destroyed by a natural hazard event.

4. Regulatory Review

This section sets out our findings from our review of the relevant regulatory and consumer protections framework to determine whether current arrangements create barriers or disincentives towards the use of SAPS for enhancing network resilience. The scope of the review is shown in Figure 18.

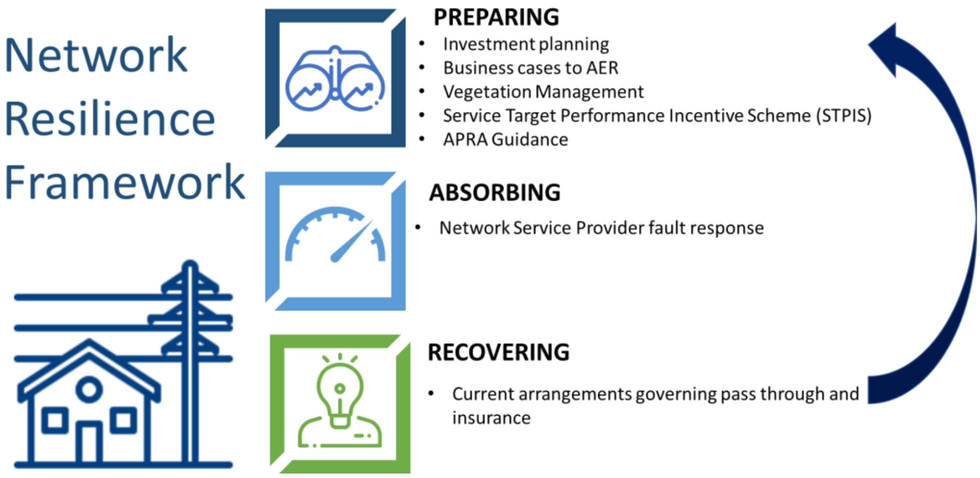
Figure 18 - Scope of the regulatory review



4.1. Current arrangements governing investment in network resilience

Building on the definition of resilience in section 2, we targeted our review to existing arrangements that allow networks to prepare, absorb and recover from natural hazard events. Figure 19 outlines our approach to the review, with the findings presented in subsequent sections.

Figure 19 - Network resilience framework



4.1.1. Measures to prepare for natural hazard events

There are a several key measures that network businesses can take to help prepare for and mitigate against the impact from natural hazard events. This section discusses these measures and seeks to examine whether there is scope for these measures to be further strengthened.

4.1.1.1. Business cases to the AER

As part of their regulatory proposal, network businesses submit expenditure proposals relating to the provision of regulated distribution network services. Expenditure proposals are often underpinned by business cases aimed at demonstrating how the expenditure contributes to the achievement of the capital expenditure (capex) and operating expenditure (opex) objectives, criteria, and factors enshrined in the NER.

Investments in resilience are not precluded under the regulatory framework, where the network business is able to establish a positive business case for the investment. In preparing business cases, network businesses make an assessment on the costs and benefits of making the investment, with most businesses applying the approach outlined in the AER's Regulatory Investment Test for Distribution or Transmission (RIT-D or RIT-T) application guidelines. These provide guidance on the market benefits that can be included, the use of scenario analysis and value of customer reliability (VCR).[33]

While the RIT provides some guidance on how networks should consider high impact low probability events and the use of VCR in undertaking cost benefit assessments, it does not specifically provide guidance on the inclusion of benefits associated with network resilience. Network resilience is a relatively new type of investment driver. The lack of guidance surrounding what market benefits can be included, the natural hazard event probabilities that can be used, and the approach for calculating resilience-related benefits may act as a barrier to networks investing in SAPS, or other systems, as a means of enhancing network resilience.

> **Network business cases**
>
> A number of network businesses, including but not limited to Ausgrid and Essential Energy, are undertaking SAPS trials in remote areas such as national parks and other densely forested areas to reduce fire risks, improve customer reliability, and provide maintenance savings.
>
> It is unclear whether SAPS business cases are likely to stack-up outside of trial arrangements given the lack of data and quality modelling to support SAPS business cases, and investment for resilience-related purposes.

This is a highly complex area of analysis and is likely something that network business lack the experience and knowledge to undertake alone. There are currently two projects underway which have the potential to help address this issue. These include:

- *Project IGNIS* – this is a project being undertaken by Energy Networks Australia in collaboration with the Bushfire and Natural Hazards CRC, Melbourne University, Essential Energy, and TasNetworks aimed at developing a methodology for valuing the impacts from catastrophic bushfire events.[34] This has the potential to assist networks in modelling the impacts from bushfire events.

[33] AER, Final Decision: Application guidelines for regulatory investment tests, December 2018.
[34] Bates, J, Penman, T, Emmett, M, Fitzpatrick, I, 2019, 'Project IGNIS: Quantifying Catastrophic Bushfire Consequences,' *Energy Networks Australia Asset Management Committee*, 5 December 2019.

- *Electricity Sector Climate Information (ESCI) Project* – the Australian Energy Market Operator (AEMO) and CSIRO are currently collaborating with the Bureau of Meteorology (BOM) on work aimed at improving the reliability and resilience of the National Electricity Market (NEM) to climate change and other extreme weather events.[35] This project has the potential to inform how the probability of natural events should be calculated. However, at this stage the ESCI project has not developed a methodology for assessing the risk of *compound* severe weather events, which are increasing in frequency.

Another potential barrier, that may be inhibiting network resilience investments, is the VCR. Currently the VCR is the only measure available for calculating the value of outages associated with natural hazard events. However, a key limitation is that the AER's standard VCR only applies to outages of up to 12 hours.[36] The AER recently consulted on an approach for calculating the value associated with wide area long duration outages (WALDO). Following stakeholder feedback the AER decided to discontinue the WALDO model and methodology and are instead considering avenues for future work, such as AER led research partnerships with universities.

Key issues raised by stakeholders included:

- That the proposed WALDO VCR was not applicable to *small area* long duration outages and was primarily aimed at calculating a value for system restart purposes.
- That the economic impacts used to develop the value were based on an extension of the AER's existing short duration VCR study. In addition, modelling of social costs was based on assumptions derived from an outdated study from the United States rather than undertaking primary research. Stakeholders raised concerns of whether the approach was appropriate for Australia's context and whether it appropriately accounted for localised factors and consumer preferences.
- The draft model produced lower values than compared to standard VCR, as by extending VCR concepts the model was unable to consider how impacts could change as the magnitude grew and instead assumed a downward sloping WALDO VCR value (as highlighted by Figure 20 below).

WALDO

The term Wide Area, Long Duration Outage (WALDO), proposed by the AER, had a precise definition in terms of load lost (between 1 GWh to 15 GWh) and was most likely to apply to events at the wholesale market level such as system black events.

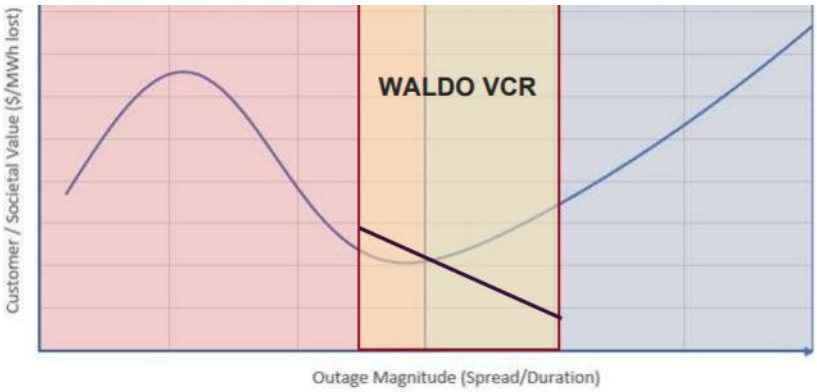
The AER had proposed a macroeconomic model including a social cost component which captured some (but not all) of the types of impacts which could be experienced by customers during an outage caused by a natural disaster.

In reviewing the literature, ACIL Allen found it was difficult to quantify social costs as they are dependent on the specific circumstances of an outage and on socio-economic conditions.

[35] See https://aemo.com.au/en/initiatives/strategic-partnerships/planning-initiatives

[36] AER, Value of Customer Reliability: Final Report on VCR values, December 2019.

Figure 20 - Theoretical value framework (updated)



Source: AEMO Submission to the AER's Consultation Paper – Values of Customer Reliability Review – Widespread and Long Duration Outages, 5 June 2020, Attachment 1: AEMO's consideration of the consultation paper, *Figure 2, p 5.*

Some DNSPs, including AusNet, Ausgrid, and Essential Energy, are already considering investing in SAPS in remote network areas to avoid significant capital expenditure, assist in mitigating the risk of damage to network assets from bushfires, and deliver other community benefits.[37] Findings from the recent NSW Bushfire Inquiry noted that SAPS may be an appropriate alternative for supplying existing grid customers in rural, remote, and bushfire prone areas and also noted the potential role they could play in restoring power on a temporary and short-term need during natural disaster events.[38]

Consequently, it is likely that more DNSPs would consider using SAPS as a means of enhancing their resilience to natural hazard events. However, without further clarity and guidance on key aspects relating to the cost benefit assessment for these types of investments, DNSPs may experience difficulties in justifying this expenditure.

Implications

There is currently no fit for purpose method, published by the AER, to evaluate outages during a natural disaster. The previously proposed approach for calculating a WALDO value for natural hazard events is not fit for purpose as it does not adequately take into account relevant social costs, consumer preferences, or reflect that the magnitude of economic impacts may actually grow alongside a longer duration of the outage experienced.

As indicated by the modelling results in Section 3, there are several benefits associated with using SAPS to improve network resilience. Greater guidance on how DNSPs should quantify these benefits and avoided social costs from natural hazard events that trigger long duration outages is likely to significantly reduce the barriers for preparing business cases for SAPS which are able to be accepted by the AER.

[37] AusNet Services, 'Electricity Distribution Price Review 2022-26 – Part III', 31 January 2020, p 147. See also, Essential Energy Standalone Power System Prototype, https://www.aer.gov.au/system/files/Essential%20Energy%20-%20Demand%20Management%20Innovation%20Allowance%20Report%202017-18.pdf and Ausgrid, 'Revised Proposal: Attachment 5.13.L – Justification for Operational Technology and Innovation Programs, January 2019.

[38] NSW Government, *Final Report of NSW Bushfire Inquiry*, 31 July 2020, p 202.

4.1.1.2. Service target performance incentive (STPIS) regime

The STPIS provides DNSPs with incentives for maintaining and improving reliability performance, to the extent that consumers are willing to pay for such improvements. This incentive regime is aimed at balancing the effects of the capital efficiency sharing scheme (CESS) and efficiency benefit sharing scheme (EBSS) so that distributors' service levels do not reduce as a result of efforts to achieve efficiency gains.

In its cost pass through application to the AER for the 2019-20 storm season, Ausgrid identified two issues with the method used to exempt networks from reliability targets during days where major natural hazard events occur (see callout box on 'Major Event Days' box for further details). Ausgrid points out that in the event of extreme storm events, the restoration effort may take multiple days as additional time is required to clear safety hazards and for field crews to work towards rebuilding parts of the network.

> **Major Event Days**
>
> A major event day is defined in the Institute of Electrical and Electronics Engineers (IEEE) standard 1366-2003, IEEE Guide for Electric Power Distribution Reliability Indices. This standard was published in May 2004. The IEEE standard excludes natural events which are more than 2.5 standard deviations greater than the mean of the log normal distribution of five regulatory years' SAIDI data (the '2.5 beta method').
>
> The 2.5 beta method is the AER's minimum or 'safe harbour' approach to setting the major event day boundary that a DNSP may propose. However, a DNSP can propose a major event day boundary that is greater than 2.5 standard deviations from the mean. Provided the AER agrees to a DNSP's proposal for a 'greater' boundary, natural hazard events that are more than the agreed multiple of standard deviations from the mean of the log normal distribution of five regulatory years' SAIDI data will be excluded.

This can lead to substantial reliability 'tails' consisting of multiple consecutive days of long SAIDI interruptions which are close to, but which do not exceed, the major event day exclusion threshold. Including the outages which come close to, but which do not exceed the MED threshold, is likely to have a significant financial impact for networks under the STPIS.[39] Ausgrid also stated that the 2.5 Beta method does not adjust for the impact of extreme events in calculating the MED threshold itself. This can have a distortionary impact by distorting the point at which 2.5 standard deviations from the mean SAIDI lies. In February 2020 alone, Ausgrid expects to incur a STPIS penalty of $10 million because of multiple days in which network reliability after a storm was close to, but did not exceed, the MED threshold.[40]

In a recent paper examining the relationship between network resilience and reliability, it was identified that the regulatory framework does not adequately consider how rapidly network businesses are able to recover from MED.[41] The current regulatory framework focuses on reliability in terms of average network performance (SAIDI and SAIFI) and seeks to minimise outage time during normal conditions as well as unplanned outages. In contrast, resilience is specifically aimed at looking at more extreme conditions on the network (i.e. MEDs) and the ability of the network to both withstand and recover from such events.[42] While investments aimed at improving network resilience may lead to improvements in reliability, the converse is not necessarily true, making the STPIS an unsuitable measure for measuring network resilience.

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[39] Ausgrid, *Ausgrid Pass-through Application – 2019-20 storm season*, 31 July 2020.
[40] Ibid, p 46.
[41] Carney, J, 2019, 'Resilience and Reliability for Electricity Networks,' *The Royal Society of Victoria*, Vol. 131, pp. 44-52.
[42] Ibid, p. 48.

Implications

As extreme climate events increase in frequency, MEDs on the lower fringes of the '2.5 beta' will start counting towards STPIS, forcing networks to consider the impact from these events under normal planning arrangements. Customers may face an initial increase in prices as networks invest more to harden the parts of their network that perform the worst when impacted by natural hazard events to avoid STPIS penalties.

4.1.1.3. Bushfire risk and emergency management plans

Most NSPs in Australia maintain a bushfire risk management plan as well as plans to respond to a range of natural hazard events under emergency conditions.

The legal obligation to develop these plan is derived from state-based safety legislation which mandates that NSPs must maintain an Electricity Network Safety Management Systems (ENSMS) in accordance with Australian Standard 5577:2013. Specifically, AS 5577 requires NSPs to undertake formal safety assessments for risk related to:

- Safety aspects arising from the protection of the environment. Including protection from ignition of fires by electricity networks; and
- Safety aspects arising from the loss of electricity supply.

In addition, Victorian NSPs have penalties in place under the f-factor scheme (see callout box) to reduce fire starts caused by network assets. Rapid earth current limiter (REFCL) technology is being installed in some parts of Victoria to help prevent powerline faults from starting bushfires as part of the f-factor scheme.

The bushfire management plans developed generally focus on mitigating the risk of ignition from network assets and tend not to address, as comprehensively, the safety aspects arising from the loss of electricity supply as a result of bushfires started by all causes (including non-network).

The recent NSW bushfire inquiry has recommended that NSW networks provide their bushfire risk management plans annually, which are to include preparedness for risks arising from network assets being affected by bushfire, as well as the risk of networks initiating a bushfire.[43] The inquiry report further sets out that mitigating actions should include consideration of

Victoria's f-factor scheme

In Victoria, the f-factor is an existing regulatory instrument under the National Electricity (Victoria) Act 2005 which specifically provides DNSPs with an incentive to lower the number of fire starts on their networks.

The scheme applies penalty weightings based on timing and location of powerline ignitions and is based on an averaged historical four-year benchmark of a distribution business network ignitions performance, making it cost neutral over the long term if network ignitions remain constant. The benchmarks decrease at set intervals to take account of new safety measures already paid for by consumers which are expected to deliver reductions in fire starts.

[43] NSW Government, *Final Report of NSW Bushfire Inquiry*, 31 July 2020, p.xii-xiii

making the electricity networks more resilient and back-up plans for emergency supply,[44] including detailed consideration of permanent SAPS.[i]

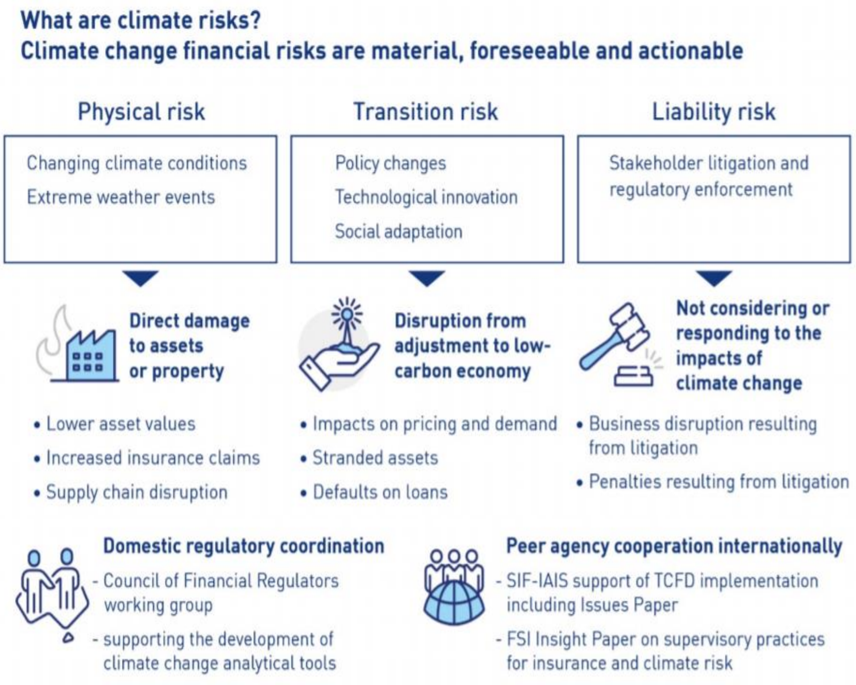
> **Implications**
> Bushfire risk management plans produced by NSPs to date tend to strongly focus on mitigating the risk of bushfires started by network assets, and are yet to comprehensively consider impacts on customer supply following bushfires started by all (including non-network) causes.

4.1.1.4. APRA guidance on managing climate change related risks

Over recent years, the Australian Prudential Regulation Authority (APRA) has highlighted the financial nature of climate change risks to its regulated entities and has recently advised that these risks are material, foreseeable and actionable.[45] APRA is taking a number of actions, as indicated by Figure 21, to ensure that regulated entities are actively seeking to understand and manage climate change financial risks as if they would any other economic and operational risks.

For example, APRA is encouraging the adoption of voluntary frameworks for assessing, managing and disclosing financial risks associated with climate change, and is in the process of developing specific industry guidance for industry participants on industry best practice for managing climate change financial risk and to provide clarity on regulatory expectations.[46] APRA has also indicated that it intends on developing a climate change financial risk vulnerability assessment including scenario analysis, stress testing and disclosure of market-useful information to support strategic decision-making.

Figure 21 - APRA's assessment and approach towards addressing climate related risks



Source: APRA, Information Paper - Climate Change: Awareness Action, 20 March 2019, p.5

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[44] Idem, p.201-202

[45] APRA, Information Paper - Climate Change: Awareness Action, 20 March 2019.

[46] APRA, *Understanding and managing the financial risks of climate change*, 24 February 2020

Implications

Privatised NSPs will likely face increasing pressure from shareholders to identify and disclose their exposure to climate-related risks and provide evidence of how these risks are being managed.

These developments may necessitate the need for the AER to provide additional guidance to NSPs on best practice approaches for managing climate related risks.

4.1.1.5. Royal Commission into natural disaster arrangements

The Royal Commission into natural disaster arrangements has recently published a set of draft propositions.[47] The draft propositions relate to issues currently being explored as part of the Royal Commission and may be used to inform the Royal Commission's findings and recommendations. Of relevance to this study are some of the propositions relating to critical infrastructure, in particular:[48]

- The need for Australian, state and government territories to undertake scenario planning to identify critical infrastructure and supply chain vulnerabilities, current capacity and future capability, as well as assisting in the development of decision support tools.
- The need for the identification and assessment of the key risks that essential service outages pose on communities in severe and catastrophic disasters
- The need for electricity networks to develop strategies, which are reviewable by regulators, that consider the community impact from electricity outages
- The need to ensure that there is sufficient back up to supply power to essential telecommunication infrastructure
- Ensuring appropriate auditing of electricity distributor's preparedness for risks arising from network assets being affected by, or igniting, a bushfire

Key implications

The Royal Commission's draft propositions support the analysis and observations made in the previous sections regarding the adequacy of current arrangements for mitigating and preparing against natural disaster events. The draft propositions highlight the need for greater risk assessment and consideration of community impacts from widespread outages, and the need for these risks to be holistically and proactively managed. Similar to the issues and themes raised by APRA, the draft propositions emphasise the need for greater upfront planning, improved risk assessment, and development of tools to support decision-making to enable owners and operators of critical infrastructure to better mitigate risks caused by natural hazard events.

Draft proposition F17 raises an issue also raised by the recent NSW Government bushfire inquiry, regarding the need for electricity networks to adopt a more holistic approach in undertaking bushfire preparedness that extends beyond mitigating against bushfire ignition caused by network assets.

[47] Royal Commission into Natural Disaster Arrangements, Draft Propositions: Counsel Assisting, 31 August 2020.
[48] Ibid, pp. 28-29.

Measures to absorb natural hazard events

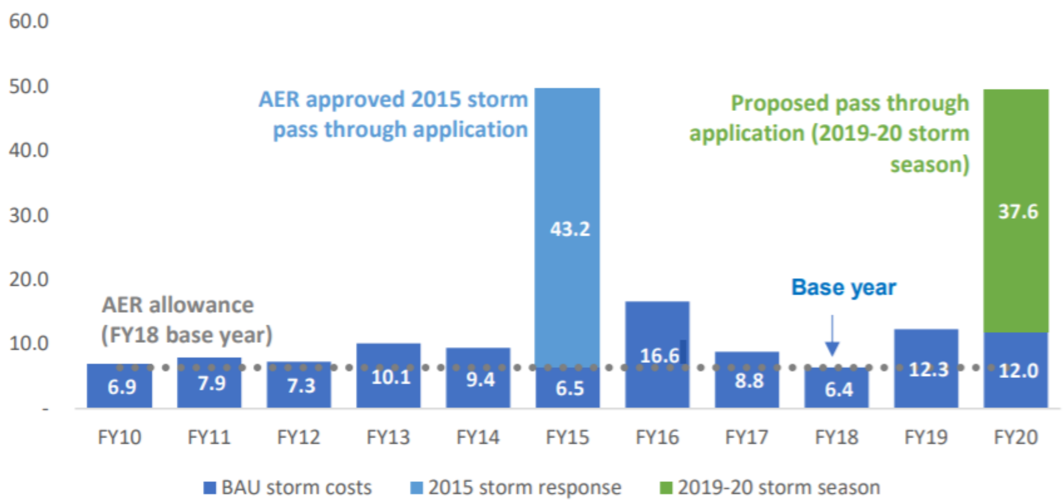
NSP fault response

NSPs generally use a 'base step trend approach' for calculating fault response expenditure in their regulatory proposals, which are calculated based on the average emergency repair costs over the previous five-year period.

In recent years, NSPs operational expenditure allowances have been declining due to regulator and internal business pressure to deliver improved efficiency and lower prices. However, as networks are increasingly faced with responding to natural hazard events with minimal field crews, outage durations are likely to extend and/or networks will increasingly need to seek assistance from other network service providers to respond to these events.

For example, during the Belconnen storm of October 2016, Evoenergy needed to contract Essential Energy staff for assistance due to the limited capacity of Evoenergy personnel. These pressures are further illustrated by Ausgrid's historical storm response costs in Figure 22 below, which highlight how the AER's allowance has typically been less than Ausgrid's actual costs for responding to network faults and emergency repair work.[49]

Figure 22 - Ausgrid's comparison of historical and FY19/20 storm response costs ($m)



Implications

Networks will come under increased pressure to maintain reliability with minimal field crews despite increasing climate events. Networks will likely experience more climate-related outages in the future, experience longer duration outages, and incur higher absorption costs. To avoid a deterioration in reliability, the AER will have to decide on how it will balance potential price rises with NSPs' request to:

- Increase opex to respond to natural hazard events
- Increase insurance premiums and coverage (see subsection further below)
- Allow capex projects that mitigate the effects of extreme climate.

[49] Ausgrid, *Ausgrid cost pass through application: 2019-20 storm season*, 31 July 2020, p. 3.

De-energisation

Some networks are also able to reduce the risk of their lines causing bushfires by 'de-energising' or shutting off the power when strong winds are forecast to accompany a high bushfire danger day. In Australia, SA Power Networks (SAPN) is currently the only network that has the authority to de-energise its lines to reduce the risk of bushfires. Allowing networks to 'de-energise' is an issue that states and jurisdictional regulators may want to consider in the future as a preventive network resilience measure, to be used during high winds in dry conditions to prevent fires from downed lines.

However, de-energisation is not without its consequences and can significantly impact local communities where this occurs for an extended period and without any corresponding backup supply. There is potential to explore the capability of behind the meter DER to operate independently or participate after an outage or de-energisation event to minimise the impact on local communities. This could include consideration on how EVs with vehicle to grid (V2G) capability and community batteries may be able to continue to operate while islanded from the grid or SAPS.

4.1.2. Measures to recover from natural hazard events

The cost pass through mechanism and insurance are the primary measures that support network business in recovering the costs associated from natural hazard events. This section examines the relationship between the two mechanisms, how they operate, and the key implications arising from the increased frequency of natural hazard events.

Pass through mechanism

Under the regulatory framework, DNSPs are able to nominate natural disasters as a nominated cost pass through event, to mitigate against the cost impacts from these events occurring.[50] Specifically, the cost pass through mechanisms allows DNSPs to seek AER approval to recover cost impacts from natural disaster events where it can be established that the event meets the pass through materiality threshold (i.e. 1% of the DNSP's annual revenue requirement (ARR)) and natural disaster definition requirements outlined in their regulatory determination to qualify as a positive change event.[51]

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[50] See National Electricity Rules, cl 6.6.1

[51] See National Electricity Rules, Chapter 10 definition of 'materially' and 'positive change event'

The cost pass through mechanism allows DNSPs to manage their exposure to natural hazard events which are beyond their control. Uncertainty surrounding the frequency and magnitude of the cost impacts from these events makes them unsuitable for including in expenditure forecasts as the associated inaccuracies with such forecast may expose customers to inefficiencies or conversely may expose DNSPs to catastrophic losses.

The increased frequency of natural hazard events has seen a notable increase in DNSPs submitting pass through applications relating to natural disaster events.

Increases in the frequency of natural hazard events and the damage to network infrastructure is likely to prompt network businesses to submit more cost pass through applications to recover the cost impact associated with more frequent severe weather events. For example, Ausgrid has recently submitted a cost pass through application to recover the costs from the 2019/20 storm events which resulted in $37.6 million in additional costs incurred during declared natural disaster events.[52]

Weather-related cost pass through applications

There has been a growing increase in the cost pass through applications being submitted for damage sustained from natural hazards.

Summarised below are a list of cost pass through applications made by networks over the past 5 years. It is interesting to note that there has been a significant jump in weather-related cost pass through applications made this year. Further cost pass through applications are anticipated from NSW networks and Victorian networks for last year's bushfires and recent storm events.

Application Date	Network	Nature of Event	Cost Impact
31 August 2020	Endeavour	Bushfire	$31.27m
31 July 2020	Ausgrid	Storm	$37.6m
10 July 2020	AusNet	Wind	$25.07m
14 May 2020	AusNet	Bushfire	$21.50m
21 August 2015	Ausgrid	Storm	$43.2m

[52] Ausgrid, *Ausgrid pass through application 2019/20 storm season*, 31 July 2020, pp. 6-7.

Insurance

Since 2019, there has been a significant withdrawal globally in insurance capacity for bushfire risks, with growing nervousness in the insurance industry about heightened bushfire risk in Australia.[53]

As a result, the level and scope of insurance coverage available to DNSPs has shrunk, with insurance being provided at significantly higher premiums. This has made it more difficult and costly for DNSPs to obtain the same level of coverage previously held. This issue has been raised by several DNSPs including the Victorian DNSPs and SAPN as part of their regulatory proposals, and by Endeavour Energy in response to consultation on SAPN's proposed step change for increased insurance costs. This has sparked the need for DNSPs to propose opex step changes for increased insurance premiums and to expand the scope of the nominated insurance cap pass through event as part of their regulatory proposals to the AER as set out below.

SAPN	AusNet	Jemena	CP/PC/UE
Applied for a bushfire insurance opex step change which has been rejected by the AER[54]	Nominated an insurance coverage and premiums cost pass-through event[55]	Nominated insurance premiums as a cost pass through event due to major environmental catastrophes[56]	Proposed an amendment to the drafting of the insurance cap event to encompass insurance coverage to reflect changes in global insurance market[57]

More frequent extreme heat days, lower rainfall, and an ongoing trend for longer bushfire seasons is likely to mean that the cost of insurance for natural hazard events can be expected to rise substantially over time. The reduction in insurance coverage and the growing lack of insurance on commercial grounds highlights the need for a renewed focus on efficient risk allocation. In particular, the need for more proactive measures, such as the implementation of SAPS solutions and other resilience measures, for efficiently managing networks' exposure to these types of risks.

[53] Marsh, 2019, *Liability market and claims overview: Victoria Power Networks and United Energy*, 29 October 2019.
[54] AER, Final Decision, SA Power Networks: Distribution Determination 2020-2025, Attachment 6 – Operating expenditure, June 2020, pp. 6-26 to 6-29.
[55] AusNet Services, 'Electricity Distribution Price Review 2022-26 – Part III', 31 January 2020, pp. 255-257.
[56] Jemena, '2021-26 Electricity Distribution Price Review Regulatory Proposal – Appendix 07-08: Managing risk and uncertainty,' 14 February 2020.
[57] Marsh, 2019, *Liability market and claims overview: Victoria Power Networks and United Energy*, 29 October 2019.

Implications

Insurance availability for managing climate-related risks is shrinking and becoming more expensive. DNSPs will need to absorb the cost of increased premiums or seek approval from the AER for an opex step change. The growing gap between insurable events will increasingly need to be managed via self-insurance if capacity in insurance markets continues to shrink, with the residual recovered via cost pass throughs. Existing regulatory arrangements currently place a greater emphasis on recovery measures as opposed to more proactive measures for mitigating the impacts from natural hazard events. This may lead to suboptimal outcomes in the long-term given current climate predictions and highlights the need for a recalibration of efficient risk allocation approaches to enable networks to more effectively manage their risk exposure in a manner that achieves the National Electricity Objective.

4.2. Current arrangements governing investment in SAPS

There are numerous SAPS across Australia owned and operated by network businesses. However, to date there has been no national framework governing these types of arrangements. Instead, SAPS not connected to the national electricity grid are currently regulated at a jurisdictional level by states and territories. The level of regulation of SAPS varies significantly by jurisdiction (see Appendix C) with some jurisdiction arrangements more developed than others. To address this issue, the Council of Australian Governments (COAG) Energy Council directed the AEMC in 2018 to undertake a comprehensive review to identify current issues and barriers to the uptake of SAPS and to develop a national framework.[58]

As part of its review, the AEMC identified several issues with existing SAPS arrangements, particularly DNSP-led SAPS relating to:[59]

- Consumer protections
- SAPS service classification and delivery
- Transitional arrangements for existing SAPS

Each of these issues is discussed in further detail below, with commentary provided as to whether the AEMC's final policy position and proposed rule package are likely to resolve barriers relating to the use of DNSP-led SAPS for network resilience purposes.

4.2.1. Consumer protection framework

Under the national electricity regulatory framework, there are several energy-specific consumer protections for grid-connected customers. National energy-specific consumer protections are found primarily in the National Energy Customer Framework (NECF),[60] the main legal instruments of which are the National Energy Retail Law (NERL) and the National Energy Retail Rules (NERR). The NECF:

[58] COAG Energy Council, *Terms of reference: Review of changes required to the national electricity framework for standalone power systems*, July 2018.
[59] AEMC, *Review of stand-alone power systems*, Draft report, 18 December 2018.
[60] The NECF currently applies, with jurisdictional specific amendments, in Queensland, New South Wales, South Australia, Tasmania and the Australian Capital Territory. The NERL and NERR do not apply in Victoria or the Northern Territory.

- Establishes the consumer protections and obligations regarding the sale and supply of electricity and natural gas to consumers (particularly residential and other small customers).
- Defines the rights, obligations and protections relating to the relationship between customers energy retailers and energy distribution.
- Complements and operates alongside the generic consumer protections in Australian Consumer Law and state and territory safety and concession regimes.

A key issue identified by the AEMC in its review was that consumer protections under the NECF would generally not be available to SAPS customers, except for SAPS in Queensland and potentially the Australian Capital Territory (ACT).[61] Due to the nature of the acts adopting the NECF in NSW, South Australia, and Tasmania, SAPS customers are unlikely to benefit from these consumer protections, as the NECF only applies to customers supplied via the interconnected national system.[62]

In Victoria, the Energy Retail Code includes provisions which are equivalent to the NERL and NERR and so may also be applicable to SAPS (if the SAPS customers are supplied by a licensed retailer).

The application of consumer protections that would apply to SAPS under current regulatory arrangements has also been identified as a critical issue. AEMC in its Final Report on Updating the Regulatory Framework for DNSP-led SAPS, the AEMC has recommended extending the application of:[63]

- The full suite of energy-specific consumer protections in the NERL and NERR to SAPS customers (in addition to grid customers)
- Jurisdictional protections, including safety and technical regulation, as well as DNSP land access rights, to DNSP SAPS and SAPS customers
- Jurisdictional reliability standards, guaranteed service level (GSL) payments and STPIS to DNSP SAPS and SAPS customers. These amendments are aimed at treating SAPS more consistently with the grid.

Implications

The AEMC's proposed rule package will introduce consumer protections that are equivalent to protections afforded to customers under the NECF and addresses a key gap in existing arrangements for SAPS and other embedded network customers.

4.2.2. SAPS service classification and delivery

A key barrier preventing greater SAPS uptake by DNSPs under current regulatory arrangements stems from uncertainty regarding the ability of DNSPs to recover costs due to the definition of distribution services in the NER and related definitions in the NEL.

[61] AEMC, *Updating the regulatory frameworks for distributor-led stand-alone power systems*, Final report, 28 May 2020, p. 106.
[62] The Acts adopting the NERL in each of these jurisdictions specify that the NERL applies only in relation to the sale of electricity to customers connected to the interconnected national grid. *National Energy Retail Law (South Australia) Act* 2011 (SA) s. 16; *National Energy Retail Law (Adoption) Act* 2012 (NSW) Schedule 1, s. 11 and *National Energy Retail Law* (NSW) No.37a, s. 3A; *National Energy Retail Law (Tasmania) Act* 2012 (Tas) s. 17.
[63] AEMC, *Updating the Regulatory Frameworks for Distributor-led Stand-alone Power Systems*, 28 May 2020.

For DNSPs to be able to recover regulated revenue from customers, the expenditure must be related to the provision of a 'distribution service' and further be classified as a direct control service. However, current drafting of the definition of a 'distribution service' is limited to services provided by means of, or in connection with, a distribution system.[64] Consequently, if a service is not classified as a direct control service, DNSPs cannot use regulated revenues to recover the costs of investing in assets that provide that service, or recover the costs of procuring such a service from the contestable market.

The implication from this is that DNSPs are unable to recover expenditure on SAPS from regulated revenue on the basis that SAPS assets (and associated services) do not meet the definition of a 'distribution services' as they are not connected to the distribution system.

A further issue identified is that the NER only permits distribution services to be classified and does not recognise "inputs" into distribution services such as the various components or activities which a DNSP uses to provide a distribution service to a customer (including assets used to provide the service). It was identified that this also contributed to uncertainty regarding what costs DNSPs would be eligible to recover under existing arrangements.

Under current arrangements, DNSPs may provide customers with a temporary generator to restore power in the event of an emergency, such as a bushfire. There are costs associated with unwinding temporary supply arrangements once they are no longer required. In some circumstances, a better customer outcome could be achieved if DNSPs were able to provide customers with a permanent SAPS in the first instance, rather than on a temporary basis in response to an emergency event.

Lastly, it was identified that uncertainty regarding the treatment of SAPS under contestability arrangements, and whether the AER's current approach to classification of services and ring-fencing, may act to prevent DNSPs from owning and controlling these assets to provide standard control services.

To address issues that have been raised, the AEMC recommended in its Final Report on updating the regulatory framework for DNSP-led SAPS that:[65]

- SAPS assets should be considered as in-front of the meter assets. This is appropriate given that the service being provided by SAPS' assets will be the same services being provided by the DNSP to grid-connected customers – that is, a supply of electricity to the customer's meter.
- SAPS should be considered to consist of two fundamental components, a SAPS distribution system which provides distribution services, and a SAPS generation system connected to the stand-alone distribution system which provides generation services directly to SAPS customers and which is also an input into the distribution service provided by a distribution business.
- There are likely to be circumstances where it may be necessary for a distribution business to provide both the SAPS distribution and generation services, for example, where contestable service providers may be unable or unwilling to provide a SAPS generation service due to remoteness or other factors.

The AEMC's position is also likely to support and facilitate the deployment of community energy projects aimed at improving communities', particularly small communities, resilience.[66] Findings from the ARENA funded National Community Energy Strategy project showed the significant environmental, social, and

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[64] See National Electricity Rules, Chapter 10, definition of 'distribution service' and also definition of 'distribution system'.
[65] AEMC, *Updating the Regulatory Frameworks for Distributor-led Stand-alone Power Systems*, 28 May 2020
[66] Community energy projects refer to projects where the communities develop, deliver, and benefit from an energy project such as solar installation or wind farm, community battery, or energy efficiency upgrade.

economic benefits from community energy but it identified access to funding and unfavourable regulatory arrangements as key barriers to greater uptake.[67]

The AEMC's rule package is likely to go some way in addressing this key barrier. However, one implication that may require further consideration is how these arrangements will work effectively in the context of an emergency event. Currently, only DNSP staff (and not third parties) are authorised to enter an affected area to restore power following a natural disaster event. If third parties are required, as the generation operators of the SAPS, they would need to be accompanied by DNSP staff requiring network businesses to engage in additional coordination activities with third parties which may impede efforts to restore power to affected customers and communities expediently.

Further changes to network planning and expansion arrangements may also be required to place positive obligations on network businesses to work with communities towards outcomes that increase their long term resilience. Work currently being undertaken through the Unlocking Community Energy in Australia project on facilitating greater co-design of community energy projects may also help to inform whether further changes to the rules may be required.[68]

Implications

The AEMC's proposed changes are expected to address key issues relating to cost recovery of DNSP-led SAPS and the classification of SAPS services. The AEMC's approach clarifies that a distribution business would be able to recover the costs associated with provision of the distribution service from its customers via retailers through standard distribution charges, consistent with the classification of these services as standard control services. It further clarified that while SAPS generation services will generally need to be provided by a third party, it recognises that generation activities may form an input into a distribution service and can be also recovered from customers as a standard control service.

The AEMC clarified that it would also be possible for DNSPs to seek a waiver from the AER to provide generation services, consistent with the AER's ring-fencing guideline. However, DNSPs have raised concerns during consultation that applying for waivers was a potential burden imposed which may act as an impediment for SAPS uptake.

The AER is currently consulting with stakeholders on how to resolve this issue and is exploring three possible options for either streamlining waivers or creating an exemption for certain types of DNSP-SAPS.[69] While this is still an evolving area, the steps the AER is taking appear positive and likely to address the concerns raised by network businesses during consultation on Updating the Regulatory Framework for DNSP-led SAPS.

[67] Coalition for Community Energy (C4CE), *National Energy Strategy*, 2015.
[68] Dr Helen Haines MP - Federal Member for Indi, *Unlocking Community Energy in Australia*, 15 May 2020.
[69] AER, *Ring-fencing interaction with distributor-led stand-alone power systems: Supplementary Explanatory Note*, June 2020.

4.2.3. Efficiency pre-condition

The AEMC's proposed changes to distribution planning arrangements to encourage the uptake of SAPS are underpinned by the position that DNSPs should only seek to transition an existing grid-connected customer to a SAPS where it has identified a SAPS solution as being the most efficient means of continuing to supply that customer.

> **Implications**
>
> Focusing on efficiency as the key determinant for transitioning existing grid-connected customers to a SAPS may be too narrow and ignores other potential drivers for transitioning customers, such as for improved resilience and safety, where customers are located in hazard prone areas.

4.2.4. Transitional arrangements

To give effect to the AEMC's proposed changes and to support the uptake of SAPS by DNSPs, a number of changes will need to be made to relevant jurisdictional instruments and to relevant AEMO processes and AER guidelines. Under the proposed rules, the AER will be required to review and amend the following guidelines by the effective date (which can be the same date as the new rules are published):[70]

- The regulatory investment test for distribution (RIT-D) application guidelines
- The connection charge guidelines
- The distribution service classification guidelines
- The asset exemption guidelines
- The cost allocation guidelines
- The distribution ring-fencing guidelines
- The distribution reliability measures guidelines
- The forecasting best practice guidelines
- The contracts and firmness guidelines
- The reliability compliance procedures and guidelines
- The MLO guidelines.

[70] See AEMC proposed rule package, *Updating the Regulatory Frameworks for Distributor-led Stand-alone Power Systems*, Saving and Transitional Arrangements, 11.[xxx].3.

The AER must review and if necessary, amend and publish by 2025, the Shared Asset Guideline.

Implications

The AEMC's recommendations to amend the NER provisions in respect of the RIT-D to mandate the quantification of applicable classes of market benefit specified in the rules (and any additional classes of market benefit specified by the AER) where these may be material or where the quantification of market benefits may alter the selection of the preferred option, is likely to support the uptake of DNSP SAPS.

4.3. Summary of key findings from regulatory review

General findings

- The AEMC's rule package for updating the regulatory framework for SAPS is likely to address many of the key barriers previously identified with network-led investment in SAPS.
- The increased frequency and severity of natural hazard events has triggered a global withdrawal in insurance for these types of events in insurance markets. This is impacting on both the availability and level of coverage for these types of events and has also resulted in a significant increase in insurance premiums. If insurance markets continue to withdraw coverage for these types of events, networks will increasingly need to self-insure or mitigate their exposure via the cost pass through mechanism.
- Current regulatory arrangements place a greater emphasis on resilience recovery measures such as insurance and the use of cost pass throughs, rather than measures aimed at preparing and absorbing the impact from natural hazard events.

Potential barriers to investment in network resilience

Our review of current regulatory arrangements has identified several issues that may act as barriers to investment aimed at enhancing network resilience. These include:

- *There is a lack of guidance and clarity surrounding the approach network businesses should adopt in preparing network resilience business cases* – in particular, what probability of natural hazard events and market benefits should be used in undertaking cost benefit analysis. Further guidance on these issues is likely to significantly improve business cases for investing in SAPS to enhance resilience. Two key projects currently underway which may assist in bridging this gap are the ESCI project and IGNIS project.
- *There is no appropriate value for valuing long duration outages* – there is currently no fit for purpose VCR value that can be used by network businesses for valuing localised long duration outages. Several issues were identified with the AER's proposed WALDO VCR value that made it unsuitable for using in resilience business cases, namely that it failed to take into account consumer preferences and was based on outdated data. It also failed to take into account that the magnitude of impacts from long duration outages were likely to increase (rather than decrease) the longer the duration of the outage. These issues led the AER to discontinue the WALDO model and methodology. Further research and analysis is required to develop a more fit for purpose VCR, which may improve the feasibility of resilience-based investment, including investment in SAPS for resilience purposes.
- *Current performance measures and incentives do not adequately address resilience* – the STPIS regime is focused on ensuring that efficiency measures do not comprise reliability, whereby reliability is measured in terms of average network performance (SAIDI and SAIFI) with an emphasis on minimising outage time during normal conditions as well as unplanned outages. There is currently no measure under current regulatory arrangements that is focused on reducing response times to MEDs.
- *Current regulatory arrangements do not adequately consider community impacts or place sufficient emphasis on measures aimed at preparing against natural hazard events* – the Royal Commission inquiry into natural disasters draft propositions has highlighted the need for electricity networks, in

determining risk mitigation and preparedness to natural hazard events, to take into account and proactively manage community impacts from network outages. The draft propositions note that electricity networks should develop strategies for preparing and mitigating against the risk of natural hazard events, which should be reviewable by relevant regulators at the request of ministers responsible for electricity networks.[71]

Areas requiring further guidance

Our review of regulatory arrangements also identified the need for additional regulatory guidance in relation to:

- *There is a need for further guidance on resilience* – other industries, such as the financial sector, are actively working with regulated entities to provide further guidance on regulatory expectations around managing climate-related risks and guidance on industry best practice for enhancing resilience.
- *There is a need for more support tools to assist network decision-making* – the Royal Commission's draft propositions and the work being progressed by APRA have highlighted the need for greater scenario analysis and stress testing of networks' resilience to natural hazard events to allow for the identification and assessment of network vulnerabilities. Having this information would support networks in determining the most efficient means for mitigating their risk exposure and minimising the impacts from natural hazard events.

[71] Royal Commission into Natural Disaster Arrangements, Draft Propositions: Counsel Assisting, 31 August 2020, p. 29.

5. Recommendations

5.1. Obtain customer views and support

It is recommended that network businesses engage proactively with their customers and customer representative groups to better understand customer expectations, priorities and value placed on resilience-based SAPS. The engagement should seek to determine the level of customer support for proactive investment by DNSPs in resilience.

5.2. Potential rule change request

Where customer support is achieved and/or where other stakeholders (e.g. customer advocacy groups) separately identify customer value for network investment in resilience, then there may be a strong case for a rule change request to be submitted.

This review recommends that any such rule change should require, inter alia, an explanation of the distinction between resilience and reliability, and the relevance of resilience to the NEO.

We recommend that any rule change request should consider the following elements:

- A definition of resilience
- A requirement for the AER to create a resilience guideline including:
    - A risk assessment framework: we expect that this will be forthcoming in 2021 from the ESCI project. This will include probabilistic treatment of individual severe weather events, and potentially an alternative approach for compound severe weather events.
    - Changes to the AER's VCR framework to recognise the costs of long duration but localised outages, potentially including social costs based on recent Australian data.
    - Changes to the STPIS Beta 2.5 methodology to reflect the increasing number and severity of major event days (MEDs).
- Changes to chapter 6 related to forecast capex and opex to require DNSPs to "maintain the reliability, security and resilience of the distribution system through the supply of standard control services" (6.5.7(a)(3)(iv)).
- Changes to broaden the considerations that a DNSP is able to consider in determining whether to transition existing customers to a SAPS to include improved resilience.
- Consideration of the impact of a resilience requirement on other incentives (e.g. the CESS and EBSS).
- Consideration of any impacts on jurisdictional reliability standards.

5.3. Natural hazard management plans

It is recommended that the AS 5577 framework be leveraged to develop natural hazard management (resilience) plans (which may include bushfire management plans and/or other natural hazards such as cyclones as appropriate). The plans should set out:

- Specific activities, including capital expenditure programs and operational or maintenance expenditure programs undertaken to reduce the risk of a network asset being affected by, or igniting a bushfire
- Specific activities including capital expenditure programs and operational or maintenance expenditure programs undertaken to reduce the impact of any natural hazard on the network asset (which may include replacing the asset with SAPS)
- The capacity to manage and respond to natural hazard events through appropriate emergency response programs, customer information systems, public communications strategies and resourcing levels
- How the network has considered and sought to mitigate against community impacts from network outages caused by natural hazard events.

In preparing their natural hazard management plans, and as set out in AS5577, NSPs should engage with state governments and emergency services to clearly set out responsibilities for emergency supply of power immediately following the event.

5.4. Future work

5.4.1. Deep dive study on existing, impacted town

An in-depth case study should be carried based on an actual town recently impacted by a natural hazard event (such as Mallacoota or Bawley Point) to better understand:

- Financial modelling implications under the AEMC's third-party ownership of generation component of a SAPS installation.
- The customer value of reliable power during and immediately following a natural hazard event.
- The community views on the design parameters for an islandable SAPS, including consideration of:
    - the number or types of facilities where a resilient power supply is highly desirable (e.g. evacuation centres, public buildings, limited number of households).
    - The community willingness/ability to reduce demand below normal levels after a natural hazard event.
- The relative risks and benefits of a diesel supplied SAPS or solar/battery supplied SAPS including consideration of diesel transport and long-term diesel use after a natural hazard event.

5.4.2. Review of technical issues associated with islandable SAPS

A technical study should be undertaken aimed at mitigating potential technical issues for islandable SAPS including, but not limited to, consideration of:

- How behind the meter DER resources interact with SAPS, including consideration of efficiently and safely isolating any premises within the SAPS impacted by the natural hazard event.
- Expanding on the work undertaken by Horizon Power's Onslow Renewable Energy Pilot to examine the role of inverters in behind the meter DER to operate independently or participate in an islanded SAPS after an outage, including consideration as to how EVs with V2G may contribute. This work would help to identify potential limitations from behind the meter DER in SAPS configurations and would include investigation into appropriate network and SAPS configurations and control systems. It would also investigate how SAPS may impact the value of customer DER through increased curtailment.

5.4.3. Study into the total potential (Australia-wide) of resilience-based DER

A study should be carried out to identify the scope for resilience-based SAPS across Australia including areas prone to both cyclones, major storms and/or bushfire events to identify total costs and benefits of a SAPS based approach, including consideration of climate change scenarios.

5.4.4. Study into the applications of broader (non-SAPS based) resilience measures for networks

A study should be undertaken which identifies a broader suite of resilience measures (not necessarily related to DER) and the relevant applications (where business cases are likely to be positive). This may include consideration of undergrounding, automation to restore supply, diversification of feeder locations (where more than one feeder supplies an area) to provide a more holistic framework for managing network resilience.

Appendix A – Reference Group members

Organisation Type	Organisation	Representative
Network	Western Power	Matthew Webb
	AusNet	Justin Harding
	Essential Energy	Warwick Crowfoot
	Endeavour energy	Matthew Browne
Industry association	Energy Networks Australia	Jill Cainey
		Hannah Farrow
		Dor Son Tan
Consumer group	Renew	Dean Lombard
Community representative	Mallacoota resident	Dr Tricia Hiley
Government agency	ARENA	Craig Chambers
		Jordan Walsh

Appendix B - Modelling inputs and assumptions

Table 2 – General assumptions

Variable	Assumption
WACC (Real Vanilla)	2.8%
Investment period	50 years

Table 3 – Natural hazard event assumptions

Variable	Assumption
Event probability	4% chance of major bushfire impacting town per year
Bushfire outage duration	12 days
Evacuation rate	30% of township evacuates (such that unserved load does not contribute to business case)
Value of customer reliability for long duration localised outage	$21.43 per kWh

Table 4 – Network assumptions

Variable	Assumption
Bushfire probability	4% chance of major bushfire impacting town per year
Standard HV feeder outage rate (not caused by natural hazard event)	0.15 outages per km per year
Standard HV feeder outage duration (not caused by natural hazard event)	2.61 minutes per km per year
Network emergency rebuild premium	20%
HV feeder rebuild cost $/km	$65,000 per km
Network maintenance costs	3% of capex
HV Network remaining life	20 years
HV feeder length	75km
Line decommissioning cost	$2,248 per km
Value of customer reliability for standard outage	$21.43 per kWh

Table 5 – SAPS assumptions

Variable	Assumption
Site establishment costs (including land costs, site preparation, housings, other SAPS costs to be 'network grade')	Individual SAPS: $40,000-$160,000 per site Large SAPS: $1.2M
Existing solar PV in township (available to SAPS at no cost)	500kW
Microgrid peak demand	Case Study 1+3: 1,500 MVA
% Load served by microgrid	Case Study 1+2+4: 100% Case Study 3: 45% of normal town load
Battery price	$741/kWh (2020)
Solar cost	$970/kW (2020)
Diesel generator cost	$250/kW (2020)
Diesel fuel price	$1.31/L
Battery lifetime	15 years (2.33 replacements within 50 years)
Solar lifetime	25 years (1 full replacement within 50 years)
Diesel generator lifetime	25 years (1 full replacement within 50 years)
Inverter lifetime	15 years (2.33 replacements within 50 years)
Battery cost decline	76% decline before first replacement then no change Based on CSIRO report: *GenCost 2019-20: preliminary results for stakeholder review*
Solar cost decline	32% decline before first replacement then no change
Diesel generator cost decline	20% decline before first replacement then no change
Inverter cost decline	32% decline before first replacement then no change
# number of isolated SAPS outside the main town	Case Study 1: 0 Case Study 2: 60 SAPS for 70 customer connections Case Study 3 and 4: N/A
Solar sizing approach	400% of peak demand
Battery sizing approach	12 hours @ average demand
Diesel generator sizing approach	100% of peak demand

Appendix C – Overview of jurisdictional arrangements for existing SAPS

Jurisdiction	Description of jurisdictional arrangements
NSW	Lord Howe Island is supplied by a microgrid exempt from the NERL. Lord Howe Island Board sets tariffs for customers, and electrical installations must comply with the Lord Howe Island Electrical Service Rules.
Queensland	Queensland is unique in that it applies the National Energy Customer Framework (NECF) and certain parts of the NER to SAPS. In addition, under Queensland law entities providing distribution services are required to obtain either a distribution authority or special approval to provide such services without a distribution authority. However, customers of SAPS operated under special approvals are less protected than customers of SAPS with distribution authorities.
Victoria	The Retail Code applies protections similar to many of those in the NECF to customers of retailers.[72] A licence is required for the supply or sale of electricity, among other activities, and exemptions from the licence requirement would not be available to SAPS retailers.[73] There do not appear to be any restrictions limiting the protections in the Retail Code to NEM-connected customers, so SAPS customers should also receive the benefit of these protections. The Distribution Code contains additional customer protection provisions that would apply to microgrid customers including restrictions on disconnection, complaint handling and dispute resolution, and provision of information.
South Australia	The Essential Services Commission (ESCOSA) regulates off-grid electricity networks under the Remote Area Energy Supply (RAES) scheme that is run by the South Australian government and includes the RAES State/Independent scheme and the RAES Aboriginal Communities scheme.
Tasmania	The Bass Strait Islands which is regulated principally under the Electricity Supply Industry Act and the Tasmanian Electricity Code provides an example of a relatively complete regulatory regime for an existing microgrid. However, these arrangements are limited to the Bass Strait Islands. The NECF does not apply to Tasmanian SAPS. Customers of any new SAPS in Tasmania would receive the benefit of the electrical safety and would also be protected by the general provisions of the Supply Act and the Code that apply to licensed electricity entities; however, SAPS would not be covered by the customer billing provisions and reliability standards that are set for the Bass Strait Islands power system.

[72] For example, there are provisions on customer retail contracts, customer hardship, disconnection of premises, and life support equipment. See Energy Retail Code Parts 2, 3, 6 and 7.

[73] *Electricity Industry Act 2000* (Vic), s. 16. General Exemption Order 2017, Victoria Government Gazette N. S 390, 15 November 2017, ss. 4-5.

Jurisdiction	Description of jurisdictional arrangements
Northern Territory	Indigenous Essential Services Pty Ltd, a subsidiary of Power and Water Corporation (PWC), performs system control, installation, operation, and management of remote electricity supply to parties outside of the Darwin-Katherine network, Alice Springs and Tennant Creek networks. This organisation operates numerous remote community micrograds (diesel and solar hybrid-based generation and distribution) under PWC's network, retail, generation, and system control licences. Other parties operating microgrids can also apply to the Utilities Commission of the Northern Territory for an isolated system license, or an exemption.
Western Australia	The Electricity Industry Amendment Act 2020 enabled Western Power to invest in and earn regulated revenue in relation to new technologies, specifically stand-alone power systems and distribution connected storage. The changes to the Access Code required to ensure that the cost of these new technologies can be recovered through regulated tariffs are: • Definition of 'alternative options' amended to refer to both a major augmentation or a new facilities investment, including stand-alone power systems and storage works • A stand-alone power system provided by a service provider is treated as part of the covered network to which it is an adjunct (provided it satisfies the new facilities investments test in section 6.52 of the Access Code).

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