Stand-alone Power Systems Cost-Benefit Analysis

April 2024

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Powercor operates electricity distribution networks supplying electricity across 64% of Victoria spanning from the Western suburbs of Melbourne through Central and Western Victoria to the South Australia and New South Wales borders, connecting 844,000 homes and businesses.

Blunomy is an international strategy consulting firm focussed on accelerating the energy transition. Blunomy partners with clients over the long term, helping design robust business models, build coalitions, and attract capital to reach scale. Blunomy works with distribution system operators to find new ways to operate and manage networks, helping to maximise the opportunities relating to energy systems' decarbonisation, decentralisation and digitalisation.

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1. Introduction

This report outlines the findings of a cost-benefit analysis conducted by Blunomy on behalf of Powercor that identified potential economically-viable regulated Stand-alone Power System (SAPS) opportunities within Powercor's Single Wire Earth Return (SWER) network. The analysis drew on Powercor-provided data to calculate the value of potential benefits from transferring customers from a network connection to a regulated SAPS[1], and on inputs from SAPS suppliers and other Distribution Network Service Providers (DNSPs) to assess the costs of the SAPS involved.

1.1 Context

A SAPS is an off-the-grid electricity supply solution typically comprising renewable generation, energy storage, and a back-up fuel-powered generator. In August 2022, the Australian Energy Market Commission (AEMC) implemented a rule change allowing DNSPs to provide SAPS to existing customers and to offer to connect new customers to existing regulated (DNSP-owned) SAPS where it is more economically efficient than connection to the interconnected national electricity system (AER, 2022).

Powercor serves over 844,000 homes and businesses across various regions, including the western suburbs of Melbourne, Central and Western Victoria. Powercor is exploring the potential to invest in a portfolio of SAPS as a part of the range of non-network solutions offered within its upcoming regulatory reset (Powercor, 2023). Blunomy was commissioned to produce an analysis of the scale and distribution of economically viable SAPS opportunities.

Powercor's extensive regional and rural networks offer potential opportunities to improve outcomes for customers through deployment of SAPS, including lower risk of initiating bushfires, and lower cost than traditional poles-and-wires approaches. Powercor believes these opportunities for regulated SAPS are likely to be concentrated within the single wire earth return (SWER) sections of Powercor's network, which represent the least-dense parts of the network, comprising over 21,000 km of lines and serving over 31,000 customers. These sections are therefore the exclusive focus of this study.

1.2 Objectives and approach

The objective of this study was to quantify the number of sites within Powercor's SWER network at which SAPS offer a cost-effective alternative to maintaining the existing distribution lines, based on a cost-benefit analysis conducted on an annualised basis.

Benefits are assessed on the basis of the disconnection of network sections. An annualised financial benefit is calculated per network section, based on Powercor inputs on network costs (Powercor, 2024b). The benefits considered include:

- **Unserved energy avoided:** The value associated with the energy at risk that is avoided by moving from a network connection to a SAPS with a lower expected total outage time per year.[2]
- **Network bushfire risk reduction:** The annualised cost relating to the risk that network assets initiate a bushfire.
- **Planned REPEX avoided:** The annualised cost of replacing network assets at end-of-life.

[1] Or, for customers with low annual consumption (<1MWh per year), helping them transition to an alternative, non-network-owned solution.

[2] It is also possible that the expected annual outage time may be greater for a SAPS than a network connection, and where this is the case a negative benefit is considered.

- **Non-network bushfire REPEX avoided:** The annualised cost of replacing network assets damaged or destroyed by non-network-initiated bushfires.
- **Maintenance costs avoided:** The annual cost of maintaining network assets.
- **Vegetation management costs avoided:** The annual cost of performing required vegetation management around lines.
- **Power generation:** The value of energy supplied within regulated SAPS.
- **Avoided line losses:** The value of the avoided lost energy in the distribution network based on the customer consumption removed.
- **Emissions costs avoided:** The value, based on the Value of Emissions Reduction (VER) published by the Australian Energy Regulator, of the avoided greenhouse gas emissions from moving from the generation mix in the wider region to the more renewable-heavy generation within the SAPS deployed.

Customers[3] residing on the network sections that are removed are considered to be transitioned to an off-grid supply solution, the nature of which depends on the energy consumption of the customer from the network. In the case of customers consuming 1MWh per year or less, Powercor judged that a customer-owned solution would be most appropriate: a support package to aid transition to this solution with an assumed average one-off cost to the network of $20,000 per customer is taken into account for these customers (Powercor, 2024b)[4]. In the case of customers consuming over 1MWh per year, a SAPS is sized according to the customer load. An annualised cost for the SAPS is calculated based on inputs from SAPS suppliers and DNSPs already operating regulated SAPS.

A net benefit is calculated per network section by summing the annualised benefits associated with removal of that section and subtracting the annualised costs associated with the SAPS or off-grid support payments for all of the customers residing on that section. A net positive result indicates that transitioning customers on that network sections to SAPS is an economically preferable option compared with leaving them network connected.

The analysis identified the maximal net-positive set of network sections for removal and transition of customers to SAPS by working in from the network edge section by section, summing cumulative benefits and costs until further expansion would eliminate any net benefit. The overall results for this set are presented below. Further details of the calculations of benefits and costs, and the sources of data inputs, are given in 3. Appendix: Methodology.

[3] It is assumed in the analysis that each NMI represents a unique customer.

[4] The figure of $20,000 is a rough estimate provided by Powercor.

2. Results

Blunomy's analysis identified 380 customers across Powercor's SWER network for which transition to a regulated SAPS would produce a positive annualised net benefit. Network removal would require an additional 643 customers consuming 1MWh or less per year be supported to transition to a customer-owned off grid solution. This portfolio of SAPS would have an estimated total capital cost of $47.38 million, and would generate an annualised net benefit of $2.89 million per year, and would incur an additional up-front cost of $12.86 million to support low-consumption customers off grid.

2.1 SAPS opportunities identified

Blunomy's analysis considered 31,558 customers on Powercor's SWER network, distributed across 29,502 network nodes. For the majority of customers, remaining connected to the wider network was the most economically efficient solution. A total of 1,023 customers (3.2% of those on the SWER network) were identified over 489 separate network sections for which removal offered a positive net benefit, comprising:

- **380 (1.2%) customers identified for transition to a regulated SAPS**; and
- **643 (2.0%) customers consuming 1MWh or less per year**, for which an alternative solution such as a customer-owned SAPS would be more suitable, and which Powercor would support in transitioning off grid. There were 287 network sections identified with no customers consuming over 1MWh per year.

Figure 1 shows these figures in the context of Powercor's full SWER network.

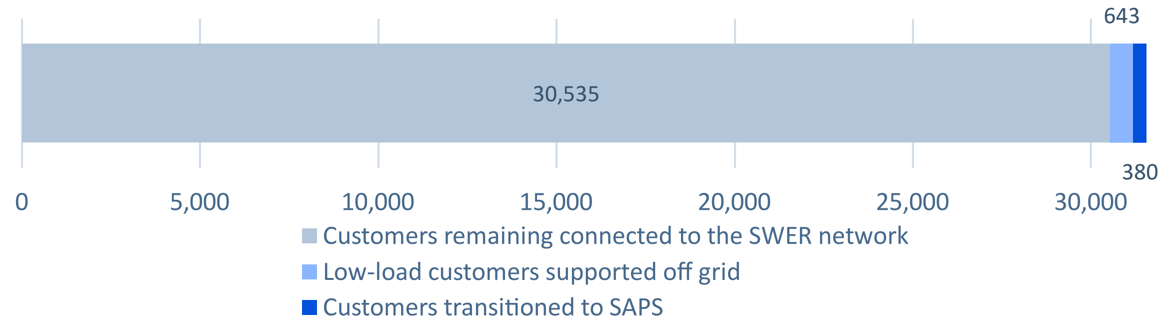

Figure 1: SAPS opportunities identified within Powercor's SWER network

Taking a whole-of-system perspective, the removal of these 489 network sections offers an annualised total benefit of $7.48 million, compared with an annualised total cost of $4.59 million, representing an overall saving of $2.89 million. This saving indicates that deployment of regulated SAPS offers a more efficient means of serving the identified customers than traditional poles-and-wires infrastructure.

Alongside the financial savings, customers would benefit from avoided unserved energy, reduced risk of network-initiated bushfires, and reduced emissions associated with electricity use:

- Customers supplied by regulated SAPS are expected, on average, to experience 4.66 hours of outages per year (Western Power, 2017). For the customers identified for transition to regulated SAPS, this represents an average of 5.46 hours of avoided outages per year.
- Removal of the 1,529 km of lines within the identified network sections would eliminate the risk of these lines causing bushfire. This represents 7.2% of the total length of the Powercor SWER network, despite hosting only 3.2% of SWER network customers.
- Generation within the SAPS envisaged would primarily be supplied by PV. Taking into account modelled consumption of diesel for back-up generation and comparing with emissions from grid-supplied

electricity based on projected emissions factors for 2024-2035, a total emissions reduction of 491 tonnes CO_2 equivalent per year would be achieved.

Figure 2 shows the locations of the network sections and sub-sections identified for removal within Victoria, indicated by the green markers. These are distributed throughout Powercor's service area, particularly concentrated in the North-West of the state.

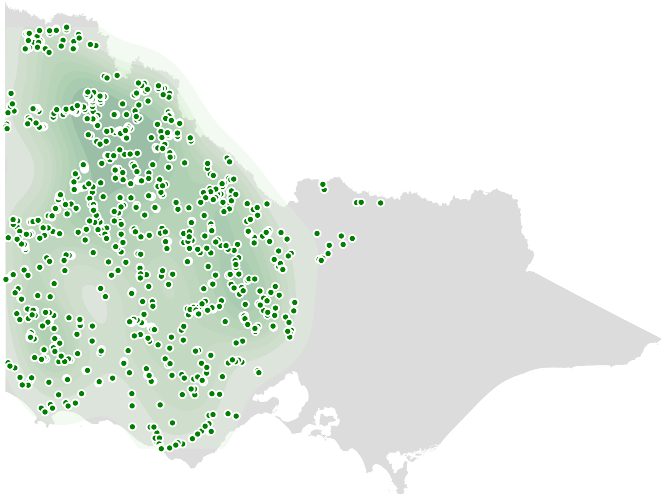

Figure 2: Location of SAPS identified

2.2 Benefits breakdown

The overall annualised benefit of $7.48 million per year is primarily driven by avoided REPEX, both planned and due to non-network bushfire damage, and by the avoided costs of vegetation management: together, these contribute 84.2% of the total. The avoided risk of bushfires initiated by network assets also makes a sizeable contribution, of 8.8% of the total, while other value streams of much lower financial importance. Figure 3 below shows the breakdown of the value stack for the entire portfolio of SAPS and removed network sections identified.

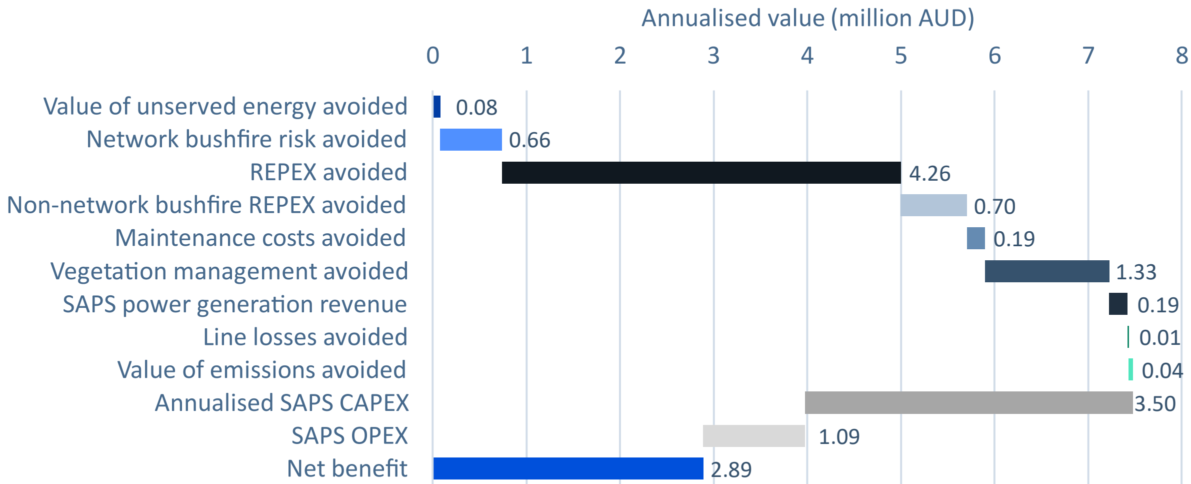

Figure 3: SAPS value streams

The financial impact of the improvement in avoided unserved energy is small compared to the total benefits, which differs from the experience of other DNSPs, for which increasing VCR was a main driver (Essential Energy, 2024). Since Blunomy's analysis has drawn from the same source when setting the expected duration of outages for SAPS, this result is explained by the relatively good reliability of Powercor's SWER network: the average SAIDI for Powercor's network over the five years 2018-2022 was 122 minutes/customer (network average performance), whereas the same metric for Essential Energy was 224 minutes/customer (AER, 2023).

2.3 SAPS breakdown

The 380 regulated SAPS opportunities identified represent an estimated total capital expenditure of $47.38 million. The average regulated SAPS identified serves a customer consuming 5.4MWh per year, at an estimated capital cost of $125k.

2.4 Sensitivity analysis

A sensitivity analysis was conducted to understand the impact on the results of variations in key parameters. Three sensitivities were considered: a heightened risk of bushfire in a future (2050) scenario; variation in the capital cost of SAPS; an increased cost associated with supported low-consumption customers off grid; and a lower threshold for designating customers as low-consumption. A summary of the results of this sensitivity analysis is given in Figure 4.

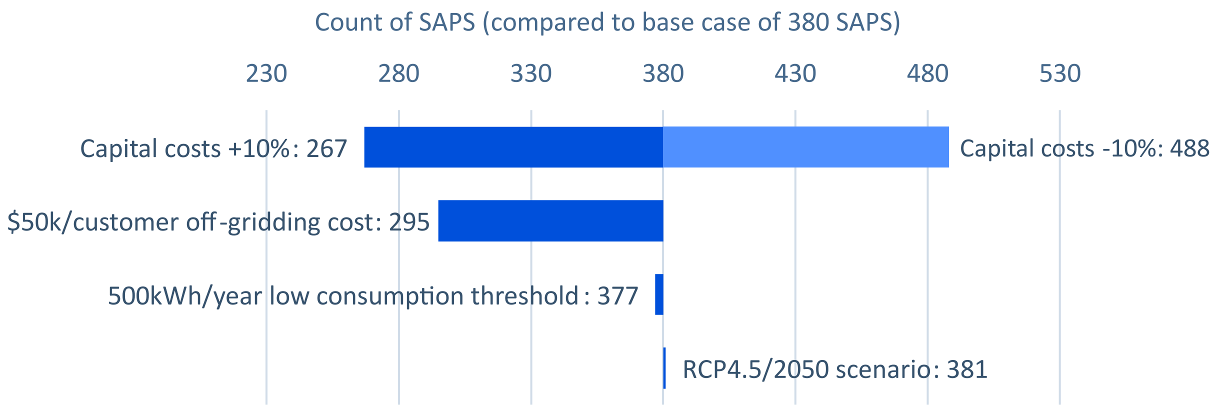

Figure 4: Summary of sensitivity analysis results (count of economically-viable SAPS identified)

2.4.1 Bushfire risk

This analysis has been conducted on the basis of inputs based on the present-day situation, and on historical analysis. Climate trends are predicted to drive an increase in the incidence of bushfires. A re-run of the analysis with inputs adjusted based on predictions for 2050 under the International Panel on Climate Change's Representative Concentration Pathway (RCP) 4.5 scenario was conducted to assess what impact this might have on the portfolio of SAPS identified.

The heightened risk of bushfire, both network-initiated and non-network-caused, brought one additional network section into positive net benefit, increasing the total number of SAPS identified to 381, and the total number of small-consumption customers to be supported off grid to 645. The portfolio-wide annualised benefit relating to network- and non-network-initiated bushfire increased by a total of $0.02 million per year. Other benefits streams increased by small amounts, relating to the additional network section removed, and an additional cost was incurred relating to the extra customers taken off grid: these increases in benefits and costs counteracted each other, producing an overall increase in annualised net benefit of $0.01 million per year. Figure 5 compares the bushfire-related benefits calculated in the base case and under this scenario.

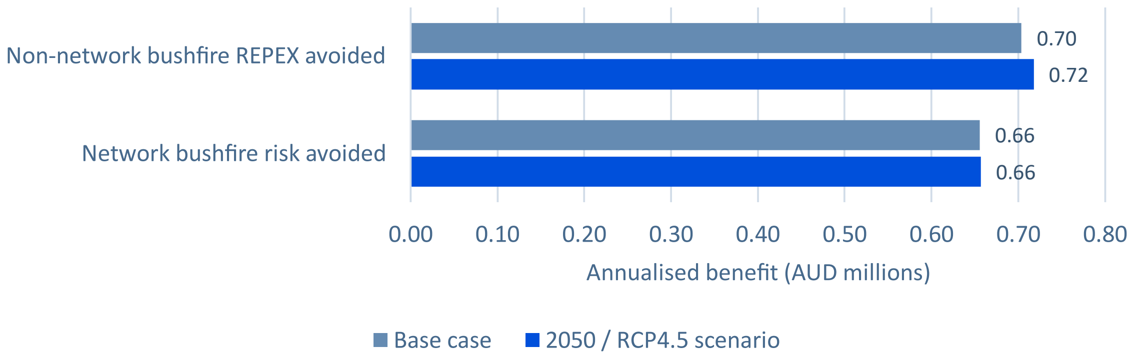

Figure 5: Comparison of selected base case and 2050 (RCP4.5 scenario) results

2.4.2 SAPS capital cost

The costs used for SAPS in this analysis are estimates and may be subject to variation: a sensitivity analysis was conducted considering a plus or minus 10% potential change in the CAPEX cost for SAPS. Table 1 summarises the results: higher costs result in fewer economically-viable sites being identified, reflected in a lower total CAPEX (despite per-unit CAPEX being higher), and vice-versa for lower costs.

Scenario	Count of SAPS	Annualised net benefit	Total CAPEX
Base case	380	$2.89M/year	$47.38M
CAPEX +10%	267	$2.63M/year	$35.34M
CAPEX -10%	488	$3.24M/year	$57.38M

Table 1: SAPS CAPEX variation sensitivity analysis

2.4.3 Cost to support low-consumption customers off-grid

This analysis assumes that regulated SAPS are not the best solution for customers consuming 1MWh per year or less. These customers are supported to transition off-grid, with an estimated cost per customer of $20,000 (Powercor, 2024b). Indications from Essential Energy, which has experience of providing similar support packages, are that these costs vary in practice, and may stretch as high as $60,000. To test the impact of a higher average cost per customers, a value of $50,000 was considered.

With this cost increase, 295 SAPS sites would be economically viable within the SWER network, a decrease of 85 from the base case, while 440 low-consumption customers would be disconnected and the annualised net benefit would decrease to $2.36M. The total capital cost for those 295 SAPS would be $35.99 million, and an up-front cost of $25.55 million would be incurred to support low-consumption customers off grid.

2.4.4 Threshold for low-consumption customers

The 1MWh per year threshold for designation of customers as low-consumption was derived from expert judgement, including building in experience from Essential Energy. To test the impact of this threshold, a sensitivity analysis reducing it to 500kWh per year was conducted.

With the reduced threshold, 377 SAPS sites were identified as economically viable, together with 440 customers consuming 500kWh or less per year to be transitioned off grid. The total net benefit would fall to $2.44 million per year. The total capital cost of the SAPS would be $41.35 million, with $8.8 million up-front cost for supporting low-consumption customers off grid.

3. Appendix: Methodology

3.1 Methodology overview

The methodology used was designed by Blunomy to quantify opportunities for SAPS based on a cost-benefit analysis. A visual summary of the methodology is given in Figure 6. There are two key streams involved:

- SAPS sizing and costing; and
- network mapping and benefits calculation.

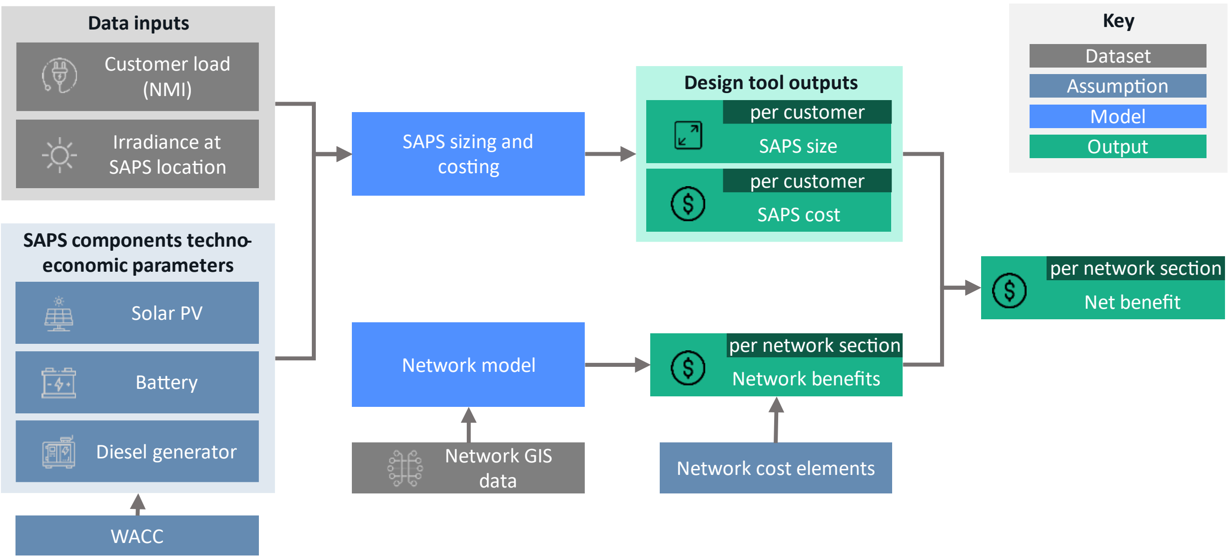

Figure 6 : Methodology overview (Blunomy, 2024b)

SAPS are sized per-customer, taking each NMI (National Metering Identifier) as a proxy for an individual customer, based on an optimization for the most cost-effective system to meet the load. Owing to a high base level of cost for a network-provided SAPS, customers with low annual consumption (1MWh per year or less) are not considered for SAPS provision but are instead allocated a nominal one-off cost for a support package to help them transition off grid to a customer-owned SAPS. Further detail on the sizing and costing of the SAPS is given in section 3.3 below. Network mapping uses GIS information provided by Powercor, and benefits are calculated based on network costs evaluated through the network mapping process. Further detail of the benefits calculation is given in section 3.4.

The benefits and costs are compared on an annualized basis at the node-level, where two or more lines converge, each potentially leading to one or several downstream nodes. The net benefit of disconnecting NMIs on all downstream nodes (i.e. for a network section) is assessed based on the total cost of the corresponding SAPS, as illustrated in Figure 7.

Blunomy believes that this methodology provides a robust basis for decision-making considering the overall portfolio of SAPS. There are, however, a number of assumptions and deliberate omissions built in that may have bearing on the detailed implementation of a SAPS program:

- **The analysis considers only single-NMI SAPS.** Where NMIs are clustered close together, it may in reality be more efficient to serve these customers from a single, multi-customer regulated SAPS, benefiting from the diversification of individual loads. Equally, if low-load NMIs are physically close to a location identified for a SAPS, additionally connecting these to the SAPS may offer a better overall solution. These considerations could be addressed as a part of the detailed planning process for implementation of a SAPS portfolio.

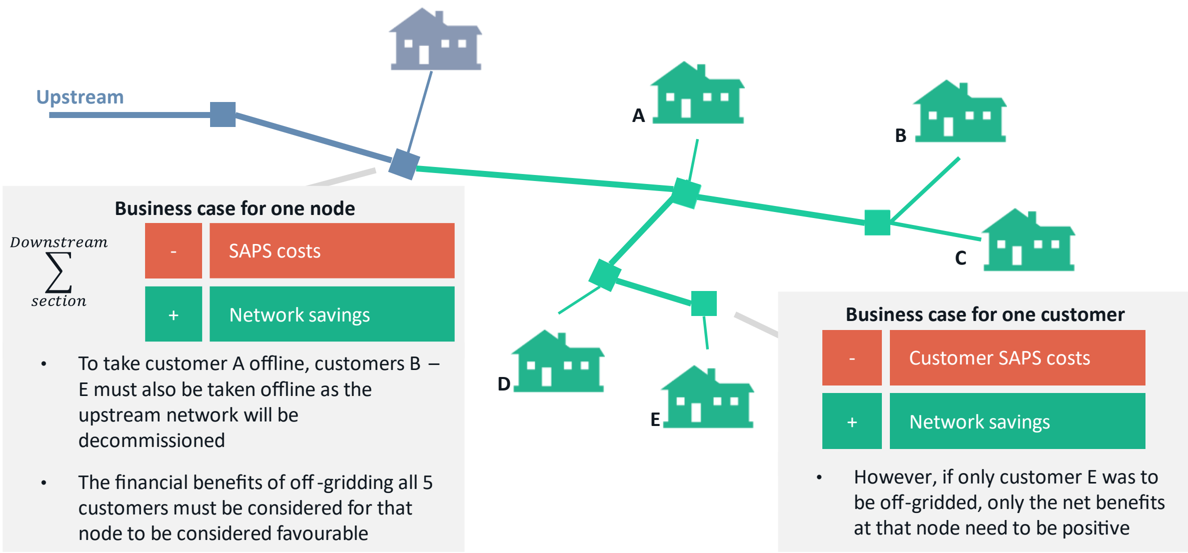

Figure 7: Node-wise cost-benefit analysis

- **This study does not consider the administrative operating costs associated with managing a portfolio of SAPS,** such as those relating to monitoring, planning, and maintaining capacity to deploy and service SAPS throughout the network. Prior to deploying the SAPS, a more comprehensive cost analysis integrating portfolio management would need to be conducted.
- **While a representative element of installation costs is included, this cost will vary significantly in practice**. Factors such as terrain and infrastructure vary between sites, impacting system design, while proximity to supplier locations has an impact on transport and travel costs.
- **The cost of the de-energisation, removal, and disposal of network assets has not been considered; nor has the lost residual value of assets removed before the end of their planned life**. There may be significant cost associated with removal and disposal in particular, but these costs are not necessarily attributable to the decision to deploy SAPS. It is envisaged that deployment of SAPS would be phased to align with planned maintenance and replacement cycles, or else progressed when existing assets are damaged or destroyed for example by bushfire. It may also be prudent to leave the customers grid connection in place for a period of time after a SAPS is installed to encourage SAPS uptake (i.e. recognising that negative customer experiences could jeopardise broader uptake of this technology).

3.2 Results validation

3.2.1 Distribution of per-node annualised net benefit

Figure 8 depicts the cumulative distribution of network sections removed by net benefits received.

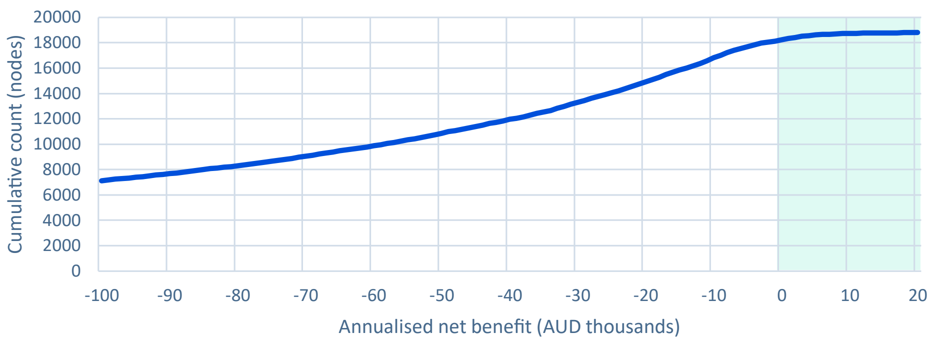

Figure 8: Cumulative distribution of network sections removed by net benefit

This cumulative distribution shows that a very small proportion of nodes have an annualised net benefit above zero (area on top right of the chart), which is the expected result. The gradient of the cumulative distribution is greatest at around an annualised net benefit of -$20,000 per year: at the $0 per year threshold, the comparatively lower gradient implies that the results obtained would not vary significantly with small changes in inputs.

3.2.2 Low-consumption NMIs

NMIs with consumption of 1MWh per year or less may represent customer sites with intermittent, seasonal, or otherwise infrequent use; may be sites with steady demand at low levels; or may have low net consumption owing to the presence of on-site generation. The best solution to assisting the transition of these NMIs to a customer-owned off-grid solution will vary and would be considered as part of the detailed planning for implementation of a SAPS program. Within this analysis, a nominal average one-off cost of $20,000 per NMI has been considered (Powercor, 2024b). Figure 9 offers some initial insight into the types of sites these NMIs may represent, based on the presence of a known PV installation.

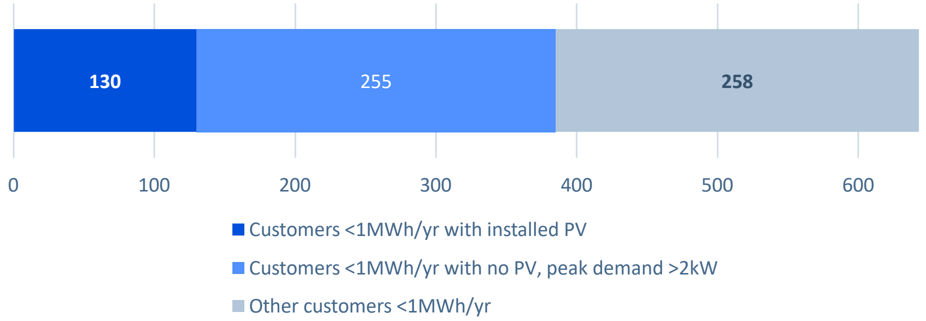

Figure 9: Breakdown of low-consumption NMIs identified for transition off-grid

3.2.3 SAPS size distribution

This analysis has considered systems sized optimally for each individual NMI identified for transition to a regulated SAPS. In practice, it is likely to be more efficient from a fleet management perspective to incorporate some level of standardisation for SAPS, either through standard SAPS sizing for a discrete range of annual consumptions or through use of common component sizes. This would be considered as a part of detailed planning for a SAPS program. Figure 10 shows the distribution of the annual consumption of NMIs identified for transition to a regulated SAPS, which could inform the selection of sizes.

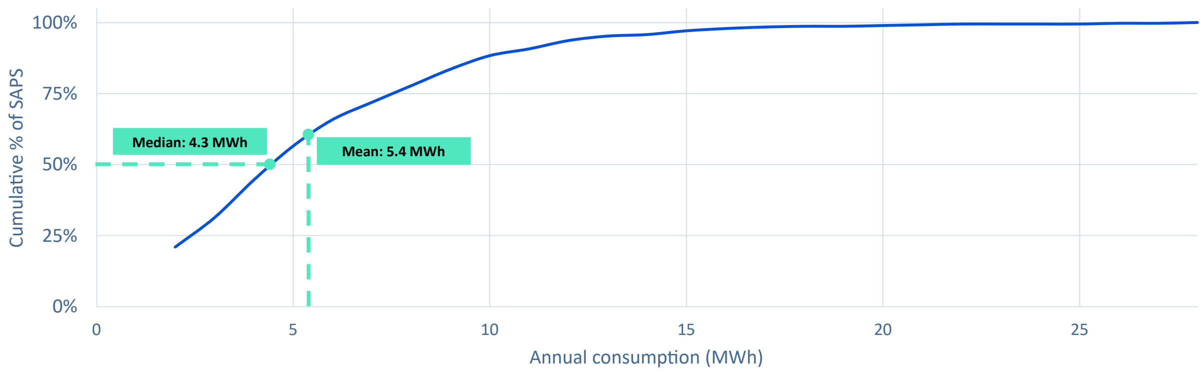

Figure 10: Distribution of annual consumption of SAPS sites identified

3.3 SAPS costing and sizing

3.3.1 SAPS costing approach

The SAPS considered for this analysis are made up of three major components, each of which represent a significant proportion of the capital cost of a SAPS: photovoltaic (PV) panels for solar energy generation, battery energy storage systems (BESS) for storing excess energy and ensuring continuous supply during low generation periods, and diesel generators (DG) for backup power. These components must be mounted, housed, connected, and controlled, requiring a significant amount of both labour and hardware not specifically related to any of the three core components.

The cost of these ancillary items can make up a large percentage of the overall SAPS cost, up to around 67% for small systems (Essential Energy, 2023). In addition to capital outlay, there are ongoing expenses for SAPS operation and maintenance, which include costs relating to monitoring performance, conducting routine inspection and maintenance tasks, and supplying diesel fuel for backup generation.

Blunomy sought inputs from several SAPS suppliers and other DNSPs to gain evidence from which to estimate SAPS costs. A summary of these inputs is shown in Table 2.

Supplier/Source	Whole of system estimated CAPEX ($)	PV system size (kW)	Battery storage size (kWh)	Diesel Generator (kVA)
Supplier 1	29,020	2	5	3
Supplier 2	36,790	4	12	10
Supplier 3 – Size A	150,000	9	24	10
Supplier 3 – Size B	200,000	12	48	16
Supplier 4	200,000	12	48	16
Supplier 5 – Size A	34,091	4	5	5
Supplier 5 – Size B	48,570	6	14	6

Table 2: Rough costings received from suppliers

Blunomy used the inputs received to construct a parameterised cost model to estimate the annualised CAPEX and OPEX for a SAPS based on the size of the components (Blunomy, 2024a)**.** Costs for the PV, BESS, and DG components were estimated based on a per-unit cost factor multiplied by the specified size of the component (in kW, kWh, and kVA respectively). The ancillary costs were modelled as having a fixed element and a variable element that scales with the overall SAPS size (for which the rated power of the PV array was used as a proxy). CAPEX and OPEX were annualised based on the assets' expected lifetimes and Powercor's average Weighted Average Cost of Capital (WACC) over the 10 years for which values were provided (3.03%) (Powercor, 2024b). The results are recorded in Table 3.

The full cost of installation was not included in this model. SAPS installation costs can vary widely, depending on site conditions – particularly the availability of suitable locations close to the metering point, the extent of groundworks required, environmental factors such as high winds or flood risk, and the distance and accessibility of the site from the installer's location (Essential Energy, 2024). Equally, there are a number of portfolio-level costs associated with the management of SAPS that have not been considered, such as integration into existing asset management and monitoring and control systems, and standing costs for maintenance, including emergency response in the case of failures.

Component	Unit	CAPEX	OPEX	Lifetime	Annualised CAPEX + OPEX
PV system	$/kW	1,442	44.44	25	127.51
Battery	$/kWh	1,177	-	15	98.83
Diesel generator	$/kVA	1,010	-	20	68.06
Installation / ancillary costs (variable)	$/kW PV	6,271	-	25	361.34
Installation / ancillary costs (fixed)	$	2,258	1,920	25	2,050.09

Table 3: Summary of SAPS component costs (Blunomy, 2024b) (Powercor, 2024b)

3.3.2 SAPS sizing approach

SAPS were sized per customer, based on an optimisation to find the least-cost combination of component sizes capable of supplying the recorded customer consumption (Powercor, 2018a)[5]. The optimisation was subject to boundary conditions as follows:

- The diesel generator was sized to supply the peak recorded demand, respecting the SAPS *quality of supply principle* that customers transitioned to a regulated SAPS should experience no worse quality and reliability of supply than if still connected to the network (National Electricity Rules (s.5.10.2), 2024).
- The minimum battery size was constrained to supply at least the 80th percentile daily energy consumption, assuming no solar generation.

Adjusting the minimum battery size creates a trade-off between cost and diesel generator usage. Increasing minimum battery size increases overall SAPS cost but decreases diesel generator usage, providing a more environmentally responsible outcome. A sensitivity analysis has been performed across different customers to explore the impacts of choices for minimum battery sizing. Different minimum sizes were ranging from no battery to a battery sized for the 100th percentile daily consumption, and the results of this are shown in Figure 11. The 80th percentile threshold for minimum battery size was selected as a reasonable trade-off.

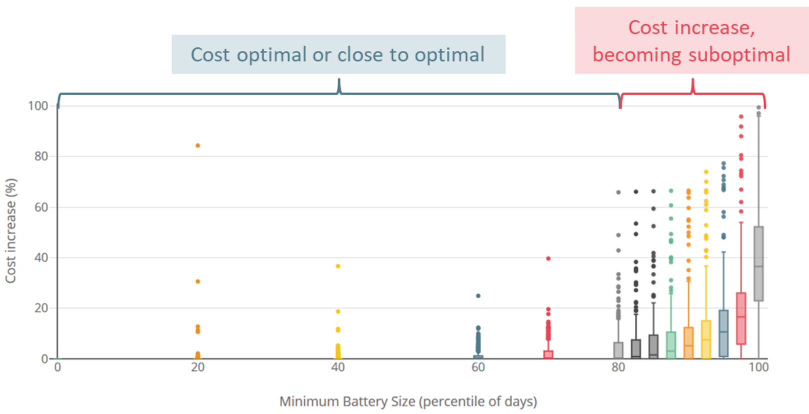

Figure 11: Sensitivity analysis of battery size and cost

[5] This study is a final iteration of a program of work begun in 2018, and 2018 data for customer consumption was used. Powercor confirmed that the slow pace of change in the SWER network means 2018 data is sufficiently representative of the current reality to produce a valid result.

3.3.3 Technical inputs and assumptions

As a part of the optimisation for the SAPS sizing, a range of input data and assumptions have been used, recorded in Table 4.

Parameter	Value	Source
Inverter DC to AC conversion efficiency	96%	(Blunomy, 2024b)
PV module - efficiency degradation factor	6%	(Blunomy, 2024b)
Battery round-trip efficiency	90%[6]	(Tesla, 2019)
Ratio of battery energy capacity to power (storage duration)	2.7 hours[7]	(Blunomy, 2024b)
Depth of discharge	90%	(Blunomy, 2024b)
Effective battery storage capacity	85%[8]	(Papezova & Papez, 2018)

Table 4: SAPS technical assumptions

The optimisation additionally assumes that the inverter is of a grid-forming type, capable of voltage and frequency regulation, and uses irradiance data for the state of Victoria to model PV output (Bureau of Meteorology, 2017).

[6] Selected due to the product's penetration in residential applications

[7] The fixed ratio of battery energy capacity to power is used as an input to establish an initial relationship between battery capacity and power which for SAPS sizing optimisation.

[8] Degradation of storage capacity (as fraction of rated capacity) assumed from published sources

3.4 Network mapping and benefits calculation

3.4.1 Overview

Benefits are assessed on the basis of the disconnection of network sections (nodes): an annualised financial benefit is calculated per node. An overview of the components included in the value stack of benefits considered is given in Table 5. The calculation method and input data for each of the value streams is described in order in the sections that follow.

Value stream	Description
Unserved energy avoided	The value associated with the energy at risk that is avoided by moving from a network connection to a SAPS with a lower expected annual outage time.
Network bushfire risk reduction	The annualised cost relating to the risk that network assets initiate a bushfire.
Planned REPEX avoided	The annualised cost of replacing network assets at end-of-life.
Non-network bushfire REPEX avoided	The annualised cost of replacing network assets damaged or destroyed by non-network-initiated bushfires.
Maintenance costs avoided	The annual cost of maintaining network assets.
Vegetation management costs avoided	The annual cost of performing required vegetation management around lines.
Power generation	The revenue gained by Powercor from supplying energy within regulated SAPS.
Avoided line losses	The value of the avoided lost energy in the distribution network based on the customer consumption removed.
Emissions costs avoided	The value, based on the VER, of the avoided greenhouse gas emissions from moving from the generation mix in the wider region to the more renewable-heavy generation within the SAPS deployed.

Table 5: Overview of value streams included in benefit calculation

3.4.2 Unserved energy avoided

The benefit associated with the avoided unserved energy per customer connected to a given node is calculated based on the net decrease in expected hours of outage, using the following formula:

$$Unserved\ energy\ savings\ = (Outage\ time_{node} - Outage\ time_{SAPS}) \times VCR \times \frac{Annual\ consumption}{8{,}760}$$

The outage time for the node and for the SAPS is the average total duration of outages per year, given in hours, while the Value of Customer Reliability (VCR) is the value associated with the energy at risk (i.e. the energy that the customer would have consumed if not for outages), and the annual consumption divided by 8,760, the number of hours in a year, is the average power demand for the customer.

Unserved energy measures typically exclude outages associated with Major Event Days when evaluating network performance. In this case, Major Event Day outages have been included in the outage time data for the nodes, to reflect the level of unserved energy actually experienced by the customer. In addition, Powercor have provided a higher value VCR applicable to customers experiencing over 500 minutes of outages per year on average (representing 13,272 customers), to reflect the increased value that customers in the worst-served areas place on reliability. The data inputs to the avoided unserved energy calculation are given in Table 6.

Description	Unit	Value	Source
$Outage\ time_{node}$	h/year	Per-DSS values provided, based on July 2020-June 2021 data	(Powercor, 2024d)
$Outage\ time_{SAPS}$	h/year	4.66	(Western Power, 2017)
VCR (<500 minutes outages per year)	$/MWh	Per ZSS values provided (ranging between $18,870/MWh and $70,970/MWh dependent on location and customer type)	(Powercor, 2024e)
VCR for worst-served customers (applicable to outage time over 500 minutes per year)	$/MWh	71,260	(Powercor, 2024b)
Customer consumption	MWh	Per-NMI data provided	(Powercor, 2018a)

Table 6: Data inputs for avoided unserved energy calculations

3.4.3 Network bushfire risk reduction

Through de-energising network sections, the risk that those sections may initiate a bushfire is eliminated. Blunomy has separately conducted an analysis of Powercor's network to examine and quantify the risk of network-initiated bushfires, based both on present-day inputs and on inputs reflecting future conditions under RCP4.5 and RCP8.5 scenarios (Blunomy, 2018, updated in 2022 and 2024). The outputs of that work have been used to inform the calculation of the financial benefit of removing sections of the SWER network. An assumption has been built into this analysis that SAPS present zero risk of bushfire initiation. In fact, despite batteries having a risk of burning, that risk is negligible as the SAPS represent a significantly smaller surface area in proximity to flammable vegetation compared grid connection. Additionally, battery enclosures with fire protection or suppression systems enable risk minimisation.

Figure 12 provides an overview of the bushfire risk model. The risk per asset and the total risk are calculated based on the likelihood of fire and the associated consequences depending on the ignition location. Figure 13 summarises a decision tree that steps through the likelihood of fire starting from an electrical fault, and the resulting magnitude of fire. Figure 14 then describes the method in which consequence is quantified and overlaid with likelihood to calculate the total risk in $/year.

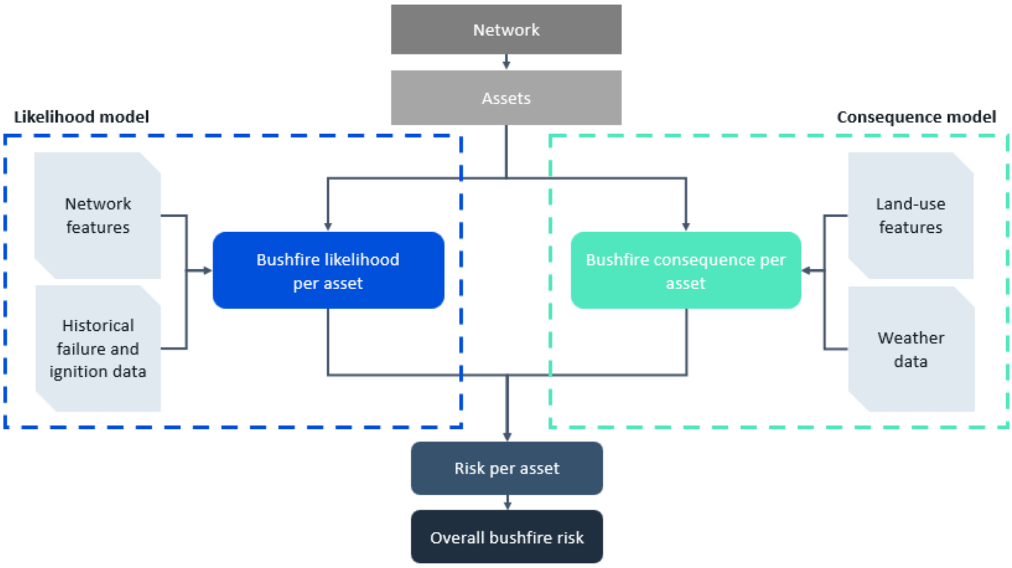

Figure 12: Overview of bushfire risk model

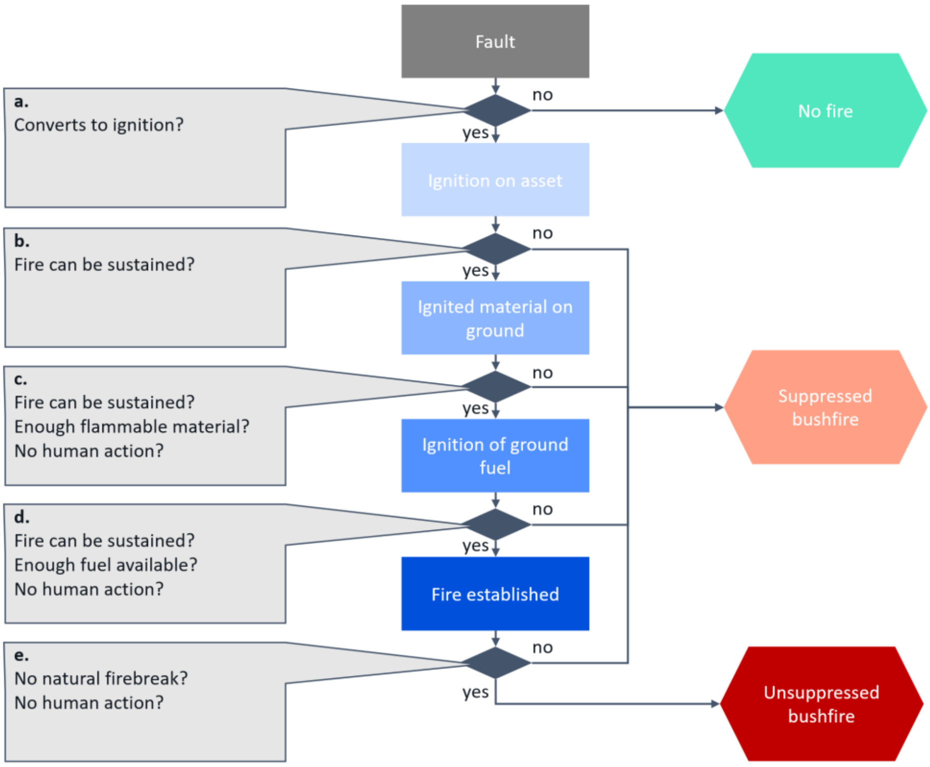

Figure 13: Likelihood of fire from electrical fault and magnitude of fire

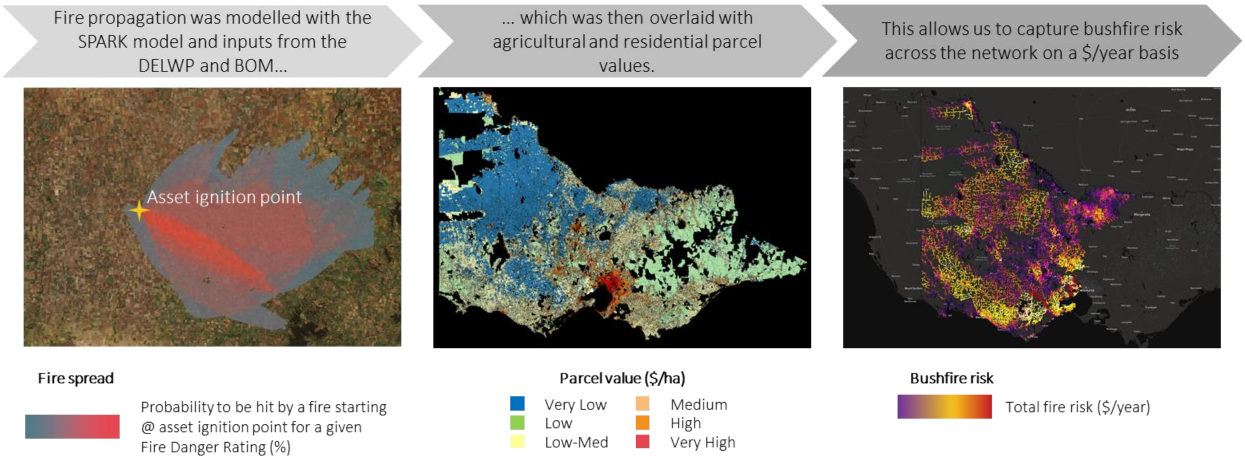

Figure 14: Summary of bushfire consequence and total risk calculation

3.4.4 Planned REPEX avoided

The removal of assets from the active network avoids the need to replace them at the end of their service life. By considering the annualised capital cost of the assets, an annualised value for the REPEX avoided can be calculated. The data inputs for the calculation of this value are given in Table 7 and Table 8; Powercor's average Weighted Average Cost of Capital (WACC) over the 10 years for which values were provided (3.03%) was used for the annualization (Powercor, 2024b).

Component	Detail	Unit	Value	Source
Transformer REPEX	Annualised replacement cost per Tx	$/Tx	10,000	(Powercor, 2024b)
	Tx nominal life	years	50	(Powercor, 2024b)
Pole REPEX	Replacement cost per pole	$/pole	11,000	(Powercor, 2024b)[9]
	Pole nominal life	years	60	(Powercor, 2024b)
	Replacement cost insulator	$/pole	$2,000	(Powercor, 2024b)
	Insulator nominal life	years	30[10]	(Powercor, 2024b)
	Conductor replacement cost	$/m	21.44	(Powercor, 2024b)
	Conductor nominal life	years	70	(Powercor, 2024b)
	Conductor replacement cost (in ELCA)	$/m	70	(Powercor, 2024b)
	Conductor nominal life (in ELCA)	years	30	(Powercor, 2024b)
	Average length of conductor per pole	m/pole	263	(Powercor, 2018b)

Table 7: Data inputs for replacement costs

[9] Estimate based on reduction from network-wide average cost per pole of $17,229 (SWER poles judged to be less expensive than an average pole)

[10] The pole unit rate includes an initial set of insulators which last half the lifetime of the pole.

Powercor-provided topological network data was used to determine the number of poles and transformers per node (Powercor, 2018b). For nodes within an Electric Line Construction Area (ELCA), Powercor is required to use covered conductors to reduce bushfire risk: these are both more expensive and shorter-lived. Topological data provided by Powercor was used to identify network nodes within an ELCA (Powercor, 2018b), (Powercor, 2024a).

The calculated annualised REPEX for each component is given in Table 8.

Asset component	Annualised REPEX
Transformer REPEX	$390.87
Pole REPEX	$1,415.31 in ELCA $667.66 elsewhere

Table 8: Summary of annualised REPEX

3.4.5 Non-network bushfire REPEX avoided

There is a risk that network assets may be damaged or destroyed by a bushfire not initiated by a network asset, meaning replacement is required before the nominal end of life. Powercor provided a time series from 2026 to 2050 for the probability that any network asset is damaged or destroyed by non-network bushfire, applicable within a High-Risk Bushfire Area (HBRA) (Powercor, 2024b). HBRAs are defined as any area not designated as low risk or undefined by the Country Fire Authority, and Powercor data was used to categorise whether each node was within a HBRA. The average value of this probability (1.32% probability of destruction per year, rising to 1.34% in 2050) was used to calculate a bushfire-adjusted life for each asset type for which REPEX was considered, according to the formula below:

$$Life_{bushfire\ adjusted} = Life_{nominal} \times \left(1 - p_{fire}\right)^{Life_{nominal}} + \sum_{n=1}^{Life_{nominal}} n \times p_{fire} \times \left(1 - p_{fire}\right)^{(n-1)}$$

This formula calculates a weighted average for the asset life, first accounting for the probability of assets reaching the end of their planned life, and second considering the probability of destruction each year, conditional on having survived preceding years undamaged. The bushfire-adjusted life was used to recalculate a value for annualised REPEX cost, and the difference between this and the base annualised REPEX cost taken as the additional REPEX saved by avoiding the risk of non-network bushfire destruction:

$$Additional\ REPEX\ due\ to\ bushfire = Annualised\ REPEX_{bushfire\ adjusted\ life} - Annualised\ REPEX_{nominal\ life}$$

The resultant annualised values, applicable to nodes in HBRAs only, are given in Table 9.

Asset component	Non-network bushfire risk avoided
Transformer REPEX	$63.84
Pole REPEX	$201.50 in ELCA $115.11 elsewhere

Table 9: Non-network bushfire risk avoided

3.4.6 Maintenance costs avoided

Network assets incur annual maintenance costs: removal of the assets avoids the need to perform this maintenance. Maintenance and inspection costs per pole were provided by Powercor, listed in Table 10. To calculate the savings produced, these costs were multiplied by the number of poles per node as defined in Powercor-provided topological network data (Powercor, 2018b).

Maintenance activity	Unit	Value	Source
Inspection costs	$/pole/year	29.20	(Powercor, 2024b)
Maintenance costs	$/pole/year	5.20	(Powercor, 2024b)

Table 10: Summary of maintenance costs

3.4.7 Vegetation management costs avoided

Where lines are surrounded by vegetation, it is necessary to periodically trim the vegetation to maintain sufficient clearance. Data indicating which spans within the Powercor SWER network require vegetation management (Powercor, 2018c) were used together with the average cost of vegetation management and average frequency of vegetation management, as in Table 11, to calculate a cost avoided for each node:

$$\begin{aligned} &Node\ vegetation\ management\ cost \\ &\quad = Number\ of\ spans\ requiring\ vegetation\ management \\ &\quad \times \frac{Vegetation\ management\ cost\ per\ maintenance\ cycle}{Maintenance\ cycle\ length} \end{aligned}$$

Parameter	Unit	Value	Source
Vegetation management cost per maintenance cycle	$/maintenance cycle	1,042/span in HBRA 324/span elsewhere	(Powercor, 2024b)
Average rural vegetation maintenance cycle length	Years	2.8	(Powercor, 2024b)

Table 11: Vegetation management input data

3.4.8 Power generation

Energy supplied within regulated SAPS is subject to a settlement price defined in regulation and set by AEMO on an annual basis: in 2023-24, the settlement price for Victoria is $80.16/MWh (AEMO, 2024). This value has been used together with consumption data supplied by Powercor (Powercor, 2018a) to calculate the value of energy generated:

$$Power\ generation\ revenue = Annual\ consumption\ at\ SAPS\ sites\ \times SAPS\ settlement\ price\ (VIC)$$

3.4.9 Avoided line losses

SWER lines are notable for their losses, owing to the resistance of the earth return path. Although Powercor was not able to provide a SWER-specific loss factor, the published Distribution Loss Factor applicable to LV customers on long sub-transmission lines was used as an acceptable, conservative alternative. The value of losses avoided was calculated using the parameters listed in Table 12, as follows:

$$Losses\ avoided = Annual\ consumption\ at\ SAPS\ sites\ \times (Distribution\ Loss\ Factor - 1) \times volume\ weighted\ average\ spot\ price\ (VIC)$$

Parameter	Unit	Value	Source
Distribution Loss Factor	N/A	1.0932	(AEMO, 2023a)
5-year average volume-weighted average spot price for VIC reference node (FYs 2018-2019 to 2022-2023)	\$/MWh	95.40	(AER, AEMO, 2024)

Table 12: Parameters to calculate value of line losses

3.4.10 Emissions costs avoided

The SAPS envisaged in this analysis rely primarily on solar generation, in contrast with the wider Victorian electricity network, which was 65% supplied by fossil fuel-powered generation in 2021-22 (DCCEEW, 2023b). The greenhouse gas emissions associated with the energy usage of customers transitioned to regulated SAPS are therefore reduced. The value of this emissions reduction has been calculated as follows:

$$Emissions_{grid\ connected} = Customer\ consumption \times Distribution\ loss\ factor \times Emissions\ factor\ for\ electricity\ (VIC)$$

$$Emissions_{SAPS} = Modelled\ diesel\ generation \times Diesel\ generation\ efficiency \times Diesel\ energy\ density \times Diesel\ combustion\ emissions\ factor$$

$$Emissions\ costs\ avoided = \left(Emissions_{grid\ connected} - Emissions_{SAPS}\right) \times VER$$

Since the emissions relating to low-consumption customers transitioned off grid are not known, this calculation considers only the consumption of customers transitioned to regulated SAPS. The factors used in the formulae are given in Table 13.

Parameter	Unit	Value	Source
Distribution Loss Factor	N/A	1.0932	(AEMO, 2023a)
Emissions factor for electricity (NEM)	kg CO_2-e/kWh	0.34[11]	(DCCEEW, 2023), (AEMO, 2023b)
Diesel generation efficiency	l/kWh	0.401	(Blunomy, 2024a)
Diesel energy density GJ/kl	GJ/kl	38.6	(DCCEEW, 2023b)
Diesel emissions per GJ diesel	kg CO_2-e/GJ	70.2	(DCCEEW, 2023b)
Value of emissions reduction (VER)	\$/tonne CO_2	87.70[12]	(AER, 2024)

Table 13: Factors for calculation of emissions costs avoided

[11] Average values over the 2024-2035 period of the draft 2024 Integrated System Plan

[12] Average of values for 2024-2035 (consistent with period considered for emissions factor), discounted by Powercor WACC (3.03%)

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