Addressing bushfire risk reclassification

Final Project Assessment Report

22 October 2024

Essential Energy

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1. Executive Summary

This final project assessment report has been prepared by Essential Energy in accordance with the Regulatory Investment Test for Distribution (RIT-D) requirements, as specified in clause 5.17.4 of the *National Electricity Rules* ("the Rules").

The purpose of this report is to demonstrate the basis for the selection of the preferred option to mitigate higher levels of bushfire risk in the newly identified bushfire priority zones.

Essential Energy has completed enhanced fire risk modelling across the entire network using the University of Melbourne's Phoenix RapidFire fire consequence model. The outcomes have seen a material shift in where the areas of highest bushfire risk exist on the Essential Energy network.

There is now a need to ensure that the existing standards and practices, for managing the risk of powerline-initiated bushfires, are also applied to the newly identified higher bushfire risk areas.

Essential Energy has determined that there is no viable non-network solution option or Stand-Alone Power System (SAPS) option that could form a signification part of a potential credible option to address the identified need. Essential Energy has published a notice in July 2024, setting out the reasons why we have determined that an options screening report is not required.

There were also several network-solution options considered in the assessment process, including undergrounding, line relocations and deployment of Rapid Earth Fault Current Limiters (REFCL). Ultimately, three options were determined to be credible in addressing the network need as listed below:

Base case	Do nothing
Option 1	Undertake **standard clear-to-sky (CTS) cutting** treatment of vegetation corridors in all newly identified bushfire priority 1 zones.
Option 2	**CTS** treatment in most newly identified bushfire priority 1 zones, **supplemented** with the **targeted installation** of some high voltage covered conductors **(HVCC).**
Option 3	**CTS** treatment in most newly identified bushfire priority 1 zones, **supplemented** with the **targeted installation** of some Stand-Alone Power Systems **(SAPS).**

The do-nothing option is not considered credible as it will result in higher than acceptable risk in newly identified higher bushfire risk area of the network, and non-compliances with jurisdictional regulatory obligations. All trees in proximity to powerlines must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and consider the risk profile associated with that location.

Option 1 involves applying the standard approach to vegetation management in bushfire priority areas, which is cutting all the vegetation near network assets to a CTS level in the highest risk areas.

Option 2 is to undertake standard CTS treatment in most newly identified bushfire priority zones, as well as installing HVCC in some specific locations along with implementing slightly narrower CTS corridors in those specific locations.

Option 3 includes undertaking standard CTS treatment in most newly identified bushfire priority zones, as well as removing powerlines and installing SAPS, in locations where it is efficient to do so, and where the impacted customer/s agree to the SAPS replacing the existing grid-connection.

The table below shows the alternative costs of the credible options to complete the project through to FY33, along with the 20-year economic assessment net present value (NPV) of those options. Option 3 presents the highest NPV of the market benefits considered in our evaluation to date. Market benefits are the risks avoided based on the Phoenix RapidFire fire consequence model which captures the risk and costs of bushfire impacts, as well as the expected value of unserved energy which is monetised using the Value of Customer Reliability (VCR). The VCR values used are those published by the Australian Energy Regulator in December 2023.

Table 1: Summary of credible options

Option	Description	Net Project Capital Cost ($m nominal)	Net Project Operational Cost ($m nominal)	Present Value Benefits ($m FY25 real)	Present Value Costs ($m FY25 real)	Present Value Net Benefit ($m FY25 real)	Benefit cost ratio	Rank
1	Clear to Sky	104.3	11.0	342.1	114.3	227.9	3.0	3
2	Clear to Sky with some HVCC	109.5	10.9	357.6	118.1	239.5	3.0	2
3	Clear to Sky with some SAPS	115.3	10.2	366.2	117.7	248.5	3.1	1

The preferred option is Option 3.

Sensitivity analysis of uncertainty in the benefits and costs of the model found the Benefit Cost Ratio and Net Benefit remained high. For example, if costs were 40% higher than estimated for all Options the project continued to have a positive Benefit Cost Ratio and Net Benefit. The same is generally true for individual assumption sensitivities (except at extreme values which are unlikely to occur), with some assumptions considered including the vegetation to ignition rate, network annual average vegetation contacts, and vegetation outage duration, amongst other assumptions.

In each scenario considered, Option 3 remained the preferred option, indicating there is a high degree of confidence in this result. Essential Energy considers that Option 3 satisfies the regulatory investment test for distribution. The detailed analysis supporting this view is set out in this report.

Essential Energy published a Draft Project Assessment Report in July 2024 and sought feedback on the preferred option from interested parties registered for RIT-D information. At the end of the required consultation period, Essential Energy had not received any submissions.

2. Context

About Essential Energy

Essential Energy is a New South Wales (NSW) state-owned electricity infrastructure company which owns, maintains, and operates the electrical distribution networks for much of NSW, covering 95 percent of the state’s geographical area. We also own and operate water and sewerage systems in the Broken Hill region, providing services to customers through Essential Water. Our customers rely on us to safely and reliably supply electricity and water services in remote, rural and regional areas of NSW.

Bushfire risk management

Bushfire risk is a category of asset event risk which may result in Essential Energy failing to meet certain elements of the National Electricity Objectives (NEO). Specifically, the risk of a powerline-initiated bushfire caused by Essential Energy assets would result in a material and detrimental impact to our customers in terms of sustained loss of power supply, property and environmental loss/damage, community economic impact and/or personal harm, injury, or death.

At a very foundational level, managing the bushfire risk associated with the electrical network involves the appropriate installation, operation and maintenance of assets (ie: the "pole and wires") and keeping vegetation clear of these assets.

In the context of this report;

- Bushfire risk does not include damage to Essential Energy assets if a bushfire is started by external factors such as a lightning strike or arson.
- Vegetation management is the risk treatment response this project is addressing.

Vegetation management requirements

The management of vegetation in the vicinity of powerlines is mandated by the Electricity Supply Act 1995 (NSW) and Electricity Supply (Safety and Network Management) Regulation 2014 (NSW). Under this Regulation, network operators are subject to direction (i.e. legally compelled) by the New South Wales Minister for Energy to take into account Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets (ISSC3:2016).

To meet Essential Energy's legally binding requirements to implement ISSC3:2016, Essential Energy determines the appropriate levels of vegetation inspection and treatment activity to be undertaken based on the safety and reliability risk profile in any given location throughout the network.

There is no option to "do nothing" for trees in proximity to powerlines. All must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and considering the risk profile associated with that location.

In areas identified as highest bushfire risk, the required standard involves the creation and maintenance of clear-to-sky vegetation corridors in addition to the horizontal and groundline minimum clearance spaces as defined in ISSC3:2016.

Modelling of highest bushfire risk areas

To meet the requirements of ISSC3:2016 Essential Energy has completed enhanced fire risk modelling across the entire network using the University of Melbourne's Phoenix RapidFire fire consequence model.

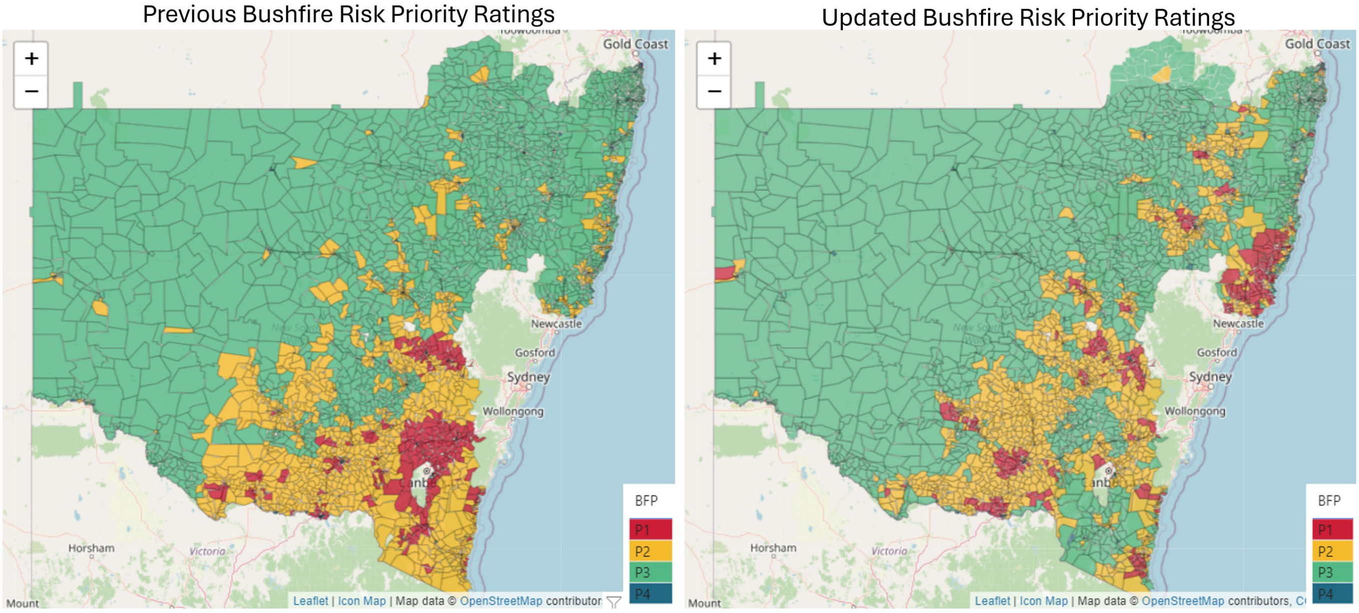
The modelling has resulted in a material shift in where the areas of highest bushfire risk exist on the Essential Energy network – refer to Figure 1. The highest risk zones are designated P1 (priority 1), medium risk as P2, low risk as P3 and urban density areas are P4.

The priority (P) zones represent the relative bushfire risk across the network. P1 zones are those locations that, if a powerline-initiated fire were to start in these areas, it would cause the greatest impact (consequence) in terms of modelled loss of houses, property, and loss of life relative to the other P zones in the network.

Figure 1: Bushfire risk mapping

Previous Bushfire Risk Priority Ratings

Updated Bushfire Risk Priority Ratings



With a deeper understanding of the bushfire risk profile across the network, there is now a need to transition and align our asset management and vegetation management standards to reflect the revised bushfire priority zones.

Enhanced vegetation standards in P1 areas

P1 zones receive a higher level of management in terms of asset and vegetation inspection and treatment. Specifically, in P1 zones Essential Energy implement the following:

- An annual pre-summer bushfire inspection of all P1 assets.
- Rectification of all identified items arising from the pre-summer bushfire inspection prior to 1 October each year.
- Enhanced construction standards for any new affected assets e.g. the application of low voltage (LV) spreaders.
- Increased prioritisation of task rectifications e.g. a maintenance item or vegetation clearance item arising from an inspection.
- Reduced rectification timelines for a maintenance item or vegetation clearance item arising from an inspection.
- Creation of “clear-to-sky” (CTS) vegetation corridors in the vicinity of powerlines.

There are 7,508km of powerline corridors in these revised bushfire priority 1 (P1) zones, that were not previously P1. Much of the asset-related activity (asset inspection and maintenance) has been transitioned to align with the revised bushfire priority zones as the scope to do so has been manageable, and able to be integrated into the existing cyclic program of works without a material impact.

The remaining transition activity is associated with vegetation management, which is the most complex in term of scope, size, community impact and cost to deploy. Specifically, for the newly identified highest bushfire priority areas (P1s), the vegetation standard[1] applicable in P1 areas is the creation and maintenance of CTS corridors wherever vegetation is near powerlines.

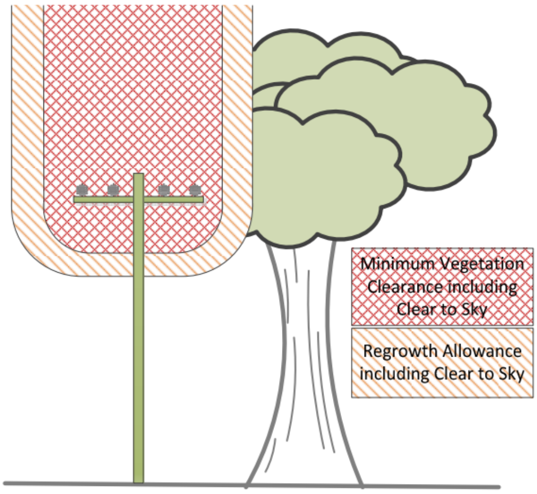
[1] Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets (ISSC3:2016)

This will require an extensive uplift in vegetation effort to transition identified corridors to CTS corridors. CTS corridors involve the clearing of vegetation that encroaches into the hashed zones identified in Figure 2 below. At times this can result in the full removal of trees located outside of the clearance corridor where it has been assessed that the trimming of limbs will result in an unstable tree with an increased risk of falling into the powerline.

Figure 2: Extract from ISSC3:2016

S1 - 3.7 Vegetation above Conductors and "Clear to the Sky" risk reduction strategy.

"Clear to the Sky" vegetation hazard reduction measures involve the practice of removing all vegetation above the Electricity Assets to the width of the minimum Clearing Requirement. This is shown in Figure 7 below.



There are currently 3,849km of powerline bays situated within the new P1 areas where vegetation has been identified that is overhanging the conductor(s).

An assessment of the impact indicates the effort to achieve the once-off transitional cutting to CTS standards, is broadly equivalent to the current vegetation management program in any given year. Once a corridor achieves CTS standard, the ongoing maintenance of this standard will require more effort, but it is relatively minor compared to the initial cutting.

Another aspect of this project is that the same resource pool (the available vegetation contractor pool in Australia) would be required to undertake both the transitional cutting works and cycle vegetation program works in parallel to each other.

Projections for the duration to complete the transitional cutting works currently sits at approximately eight years, spread over two regulatory periods. This timing is dependent on the rate of expansion of the vegetation contractor resource pool, market forces, workforce efficiency initiatives, and contracting models deployed.

Validation of effort

The scope of the project has been established via desktop analysis using available data. There are 290 affected Vegetation Management Areas [2](VMAs) in the new P1 areas and to assess each of these using

[2] A VMA is how the Essential Energy network is divided for the purposes of managing the cyclical vegetation treatment program. VMAs are issued to Contractors as a works package and are used for progress tracking and payment purposes.

qualified vegetation scopers would take at least 2-3 years, at which time the state of the vegetation would have changed given its dynamic nature, weather patterns and growth rates.

To support the data-driven scoping exercise, the physical treatment of three "pilot" VMAs to CTS standards was completed. The three VMAs were selected initially to represent a high complexity VMA (high tree density), a medium and low complexity VMA. These learnings were applied across the full spectrum of impacted VMAs to further inform and refine the scope, potential program costs and a transition plan. The samples chosen included two VMAs on the Mid-North Coast as this area has been impacted the most by an increased volume of new P1 VMAs. This choice was considered representative of the incremental work to transition the new P1 areas. Since then, we have refined the modelling and established that all the pilot VMA's were at the lower end of the complexity scale.

Essential Energy's vegetation transition plan must accommodate the continuation of the existing business-as-usual cycle vegetation program, and the undertaking of this transitional cutting project, whilst also optimising for resource deployment and efficiencies.

3. Identified need

Regulatory compliance obligation

As discussed earlier, the management of vegetation in the vicinity of powerlines is mandated by the *Electricity Supply Act 1995* (NSW) and *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW). Under the Regulation, network operators are subject to direction (i.e., legally compelled) by the New South Wales Minister for Energy to take into account the Industry Safety Steering Committee Guide for the Management of Vegetation in the Vicinity of Electricity Assets (ISSC3:2016).

ISSC3:2016 prescribes CTS treatment for areas identified as high bushfire risk.

Coronial Inquiry requirement

The New South Wales ("NSW") Bushfires Coronial Inquiry (following the Black Summer 2019/20 bushfires) identified that the legacy bushfire risk classification system (including the fire risk map and Pheonix modelling, in widespread use across the industry) was "not appropriate or fit for purpose in the lead up to the 2019/20 bushfire season nor at the time the inquiry was heard" [3].

Two recommendations (27 and 28) from the inquiry, were for Essential Energy to take into account the identified bushfire risk model limitations as Essential Energy updates the fire risk modelling, and to share the findings from the inquiry with Energy Networks Australia and the IGNIS Project Team.

In addition, Essential Energy is required, in accordance with Premier's Memorandum M2009-12 - Responding to Coronial Recommendations, to write to the Attorney General (within 6 months) outlining the action taken by Essential Energy to respond to the Findings and Recommendations of her Honour Coroner O'Sullivan following the Coronial Inquiry into the Black Summer Bushfires 2019-2020. Essential Energy complied with this obligation on 27 September 2024 and shared the following further information:

- Essential Energy has completed the transition of the following bushfire risk management activities to reflect the revised bushfire priority zones:
    - The annual pre-summer bushfire inspection program is now occurring in the revised highest bushfire risk areas.

[3] https://coroners.nsw.gov.au/documents/reports/bushfires/NSW-Bushfires-Coronial_Inquiry-2019-2020-Vol-2.pdf

  - The asset management systems have been updated to reflect the revised zones
  - Maintenance tasks identified in the revised zones are actioned and prioritised in accordance with policy pertaining to the highest bushfire risk areas.

- Essential Energy is progressing the transition of its vegetation management activities:
  - A vegetation transition project team was established in July 2023 to develop a vegetation transition plan and to obtain the required funding to undertake the works.
  - Significant data analysis, scope quantification, pilot area vegetation treatment and estimating models have been progressed and/or completed.

Government expectations

In early 2024 the Department of Climate Change, Energy, the Environment and Water (DCCEEW) issued its National Climate Risk Assessment[4]. This report identifies risks to the provision of essential services and to regional and remote communities arising from climate change. The intention of the work is to inform adaptation measures, such as the shift in treatment of the newly identified highest bushfire risk areas on Essential Energy's network.

Investment objectives

By investing in its network in the manner described in this report, Essential Energy's objectives are:

- to comply with its regulatory compliance obligations under the *Electricity Supply Act 1995* (NSW) and *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW), as described above;
- to take the actions required of it by the outcome of the Coronial Inquiry, as described above;
- to align its activities with government expectations, as set out in the DCCEW report described above; and
- in doing so, to deliver improved safety and reliability to its customers, resulting in economic benefits to those customers, as explained in section 7 below.

In identifying the 'identified need' described in this section, Essential Energy has not made any relevant assumptions.

4. Non-network solutions assessment

In July 2024, Essential Energy published its non-network screening notice. It has determined that there are no non-network options that can form a significant part of any credible solution to appropriately address the project need in a prudent and efficient manner.

Essential Energy's determination was made under clause 5.17.4(c) of the Rules and was published pursuant to clause 5.17.4(d). In accordance with those provisions, Essential Energy will not be publishing a non-network options report in relation to this project.

In summary, Essential Energy's reasons for this conclusion are:

[4] National Climate Risk Assessment - First pass assessment report (dcceew.gov.au)

i. In areas identified as highest bushfire risk, the required vegetation management standard involves the creation and maintenance of CTS vegetation corridors *in addition* to the horizontal and groundline minimum clearance spaces as defined in ISSC3:2016.

ii. In isolated cases, alternate powerline solutions are deployed to reduce or avoid vegetation treatment where technically and economically prudent to do so e.g., powerline relocations, undergrounding of overhead powerlines, or use of HVCC.

iii. The only alternate *non-network solution* relating to the management of vegetation near powerlines is to permanently *remove* the powerlines and therefore remove the risk of vegetation-initiated powerline bushfires.

iv. The identified line length for this project that is subject to CTS cutting is 3,849kms. Tens of thousands of customers are reliant on these powerlines, making permanent removal a non-viable solution.

v. Removal of powerlines is only possible where there is *an alternate source of supply provided* to the customers reliant on that powerline. This is addressed by installing SAPS to each affected customer.

vi. Powerline removal coupled with the provision of SAPS for each impacted customer is not a practicable option to be deployed *at scale* given the 3,849kms of powerlines in the new P1 areas identified as requiring CTS cutting. Further detail regarding where SAPS can replace vegetation cutting is provided in section 5 'Credible Options' of this report.

Essential Energy's 2024-29 regulatory determination included approval and funding for up to 400 SAPS across the full network footprint. We have reassessed our SAPS program and incorporated the additional CTS cutting costs into our economic assessment. In doing so, we have increased the use of SAPS as viable solutions in these new P1 locations. We estimate that there are likely 64 sites where we do not need to undertake the CTS work, as SAPS may be installed, and the powerlines removed instead. This means that we are now forecasting that we could remove up to 66km of CTS cutting costs from this Bushfire Risk Reclassification program. Some ongoing vegetation and powerline maintenance costs can also be avoided. Our assessment indicates that less than 1% of the project scope may be addressed by SAPS, hence this solution has been discounted as a viable non-network solution that could significantly replace the need to undertake the 7,508kms of vegetation transition works in the new P1 areas.

5. Credible Options

The base case of 'Do Nothing' reflects the business taking a reactive approach to the increased bushfire risk in the newly identified P1 areas, and just treating them in due course, or dealing with powerline-initiated bushfires as/if they occur. This option is not compliant with our jurisdictional regulatory obligations nor does it align with the recommendations from the Coronial Inquiry into the 2019/20 NSW Bushfires, nor with government expectations regarding the management of climate change risks to regional communities (as set out in the DCCEW's report). Further, it does not align with the safety and network reliability requirements of the NEO.

The credible solutions to address the identified need are:

Option 1

Complete the vegetation trimming and tree removals in powerline corridors in the new P1 areas to meet the CTS standards. This is the accepted strategy for P1 areas and would be applied to 100% of the new P1 areas that are currently non-CTS, i.e. 3,849kms of powerline corridors to undergo initial CTS treatment.

This option is considered standard and good practice amongst all Australian electricity network service providers and is the adopted approach in designated high bushfire risk areas. This option includes (real

FY$25) capital expenditure of $92.2M and operating expenditure of $9.4M, totalling $101.6M over the duration of the project, and with a 20 year net economic benefit of $227.9 (NPV). Legal, regulatory and administrative costs for this option have been included in the capital expenditure amount and are likely to be consistent with those quantified for Option 3, as set out in Table 3.

Option 2

Implement a combination of CTS treatment of vegetation corridors, and the replacing of bare overhead wires with HVCC where it is economically efficient. HVCC is a type of overhead conductor where individual phases are insulated. Being insulated, the potential for ignition is reduced compared to bare overhead wires. HVCC has other benefits such as:

- reduced faults from both vegetation and non-vegetation contact i.e.: bird strikes on the powerline
- the CTS treatment can be done to a slightly reduced standard (the vegetation corridor doesn't need to be quite as wide)

Our analysis to date indicates that this could be technically and economically feasible to deploy for about 50km, which is less than 2% of the target powerline length targeted for CTS treatment, with the remaining 98% requiring the standard CTS treatment.

A key point to note is that where HVCC is deployed, a CTS corridor *must still be established* and maintained to meet our regulatory powerline vegetation clearance requirements, however the corridor can be narrower therefore incurring a marginally lower vegetation treatment cost compared to Option 1. This option includes (real FY$25) capital expenditure of $96.9M and operating expenditure of $9.3M, totalling $106.2M over the duration of the project, and with a 20 year net economic benefit of $239.5M (NPV). Legal, regulatory and administrative costs for this option have been included in the capital expenditure amount and are likely to be consistent with those quantified for Option 3, as set out in Table 3.

Option 3 – Preferred option

Undertake a combination of CTS treatment of vegetation corridors, plus removing some bare overhead wires and installing SAPS in locations where it is economically more efficient to deploy this option and the customer has also agreed to the SAPS solution.

SAPS are a type of non-network solution that in recent years has become a more viable alternative to traditional poles and wires construction in certain (bespoke) locations. Generally, these systems employ the use of solar panels, batteries and backup diesel generators, however, Essential Energy is technologically agnostic and is also exploring other technologies such as hydrogen.

SAPS are usually viable solutions where there is a long rural powerline (e.g. typically >1km in length) supplying 1 or 2 supply points of low energy usage. Thus, the cost of a SAPS is kept comparatively low due to the low energy requirements, and the economic benefit is larger due to avoided costs of the longer powerline length and the related asset maintenance and vegetation costs over the life of the powerline.

It is also desirable and practical to have a very small number of customers impacted by the powerline removal. Each customer will generally require their own SAPS (a high cost per location) and each impacted customer must provide their explicit informed consent to converting their property, home and/or business to an off-grid SAPS solution before the powerline can be removed. Thus, the smaller the number of impacted customers, the higher the success rate of implementing a SAPS.

Given the above criteria, and as described in section 4 Non-network solutions assessment, we have assessed that we could potentially remove 66kms of powerlines in the newly identified higher bushfire risk zones by replacing existing customers' power supplies with a SAPS. If achieved, this represents < 1% of the targeted vegetation corridors that would no longer require CTS treatment. This option includes (real FY$25) capital expenditure of $102.0M and operating expenditure of $8.7M, totalling $110.7M over the duration of the project, and with a 20 year net economic benefit of $248.5M (NPV). Legal, regulatory and administrative costs for this option have been included in the capital expenditure amount and are set out in Table 3.

Whilst Option 1 is the standard approach for the bulk of the program, it does not account for site-specific complexities, such as density of vegetation, existing reliability performance and site access issues. For example, in extremely high tree density locations, the cost benefit of a SAPS installation (Option 3) would include the cost saving from eliminating the need for complex vegetation removal and the ongoing vegetation corridor management. In these cases where the cost benefit outweighs that of standard CTS treatment, a SAPS solution will be pursued with the affected customers.

Our economic analysis confirms Option 3 to be the preferred option over the lifecycle of the assets. Following the six-week public consultation period, during which no submissions were made, Option 3 remains the preferred option.

Other options reviewed

The inclusion of undergrounding as part of the solution was assessed and rejected due to the relatively high cost of this solution (cost per km comparison) versus the cost for HVCC and vegetation CTS treatment.

Line relocations were also not considered a viable solution *at scale* due to the remaining need for CTS work unless the line was relocated a significant distance (increasing costs and potentially not technically feasible for many locations), and the potential for community and property owner backlash.

REFCLs were also dismissed as they are not a cost-effective solution and do not avoid the requirement to maintain vegetation clearances from Powerlines. REFCLs would incur significant additional cost compared to all the other potential and assessed options and would not provide the necessary mitigation of risk.

6. Consideration of non-network solutions

Essential Energy has determined that there are no non-network options that can form a significant part of any credible solution to appropriately address higher levels of bushfire risk across the network, because of the reclassification of bushfire risk.

Essential Energy's determination was made under clause 5.17.4(c) of the Rules and is published pursuant to clause 5.17.4(d). In accordance with those provisions, Essential Energy has not published a non-network options report in relation to the proposed risk mitigation works to address the heightened risk rating to satisfy compliance requirements of its updated Bushfire Risk Management Plan. The background to the identified need is also described in our proposed Contingent project[5] for Bushfire Risk Reclassification, which was approved by the AER in its 2024-29 Final Determination for Essential Energy.

Essential Energy expects most of the work to address the need, to involve upgrading of the vegetation clearances around assets in newly identified higher risk areas to meet the clearance standards. This is in addition to some other potential solutions which may make up a minor part of the optimal solutions developed.

Rationale that there are no viable non-network solutions

The management of vegetation in the vicinity of powerlines is mandated by the *Electricity Supply Act 1995* (NSW) and *Electricity Supply (Safety and Network Management) Regulation 2014* (NSW). Under the Regulation, network operators are subject to direction by the New South Wales Minister for Energy to take into account ISSC3:2016.

[5] Essential Energy - 8.03 Proposed Contingent Project - March 2024 | Australian Energy Regulator (AER)

In meeting the requirements of ISSC3:2016, Essential Energy determines the appropriate levels of vegetation inspection and treatment activity to be undertaken based on the risk profile in any given location throughout the network.

There is no option to “do nothing” for trees in proximity to powerlines. All must be assessed and treated (trimmed or removed) to maintain minimum clearance space requirements and considering the risk profile associated with that location.

In isolated cases, alternate network solutions are deployed to reduce or avoid vegetation treatment where technically and economically prudent and efficient to do so e.g., powerline relocations, undergrounding of overhead powerlines, or the use of HVCC.

The only alternate non-network solution relating to the management of vegetation near powerlines is to permanently *remove* the powerlines and therefore remove the risk of vegetation-initiated powerline bushfires.

The identified line length for this project that is subject to CTS cutting is 3,849kms with a total of 7,508kms of newly upgraded P1 network that will be treated to adhere to P1 bushfire risk compliance. Tens of thousands of customers are reliant on these powerlines, making permanent removal a non-viable solution.

The case for Stand Alone Power Systems (SAPS)

Because Essential Energy is obliged to supply electricity to customers under the *National Energy Retail Law (NSW)*, removal of powerlines is only possible where there is *an alternate source of supply provided* to the customers reliant on that powerline. This is addressed by installing SAPS to each affected customer. Powerline removal, coupled with the provision of SAPS for each impacted customer, is not a practicable, prudent or efficient option to be deployed *at scale* given the 3,849km of powerlines in the new P1 areas identified as requiring risk mitigation.

- A key limiting factor to the deployment of SAPS is that for any powerline to be removed, all affected customers currently supplied by that powerline must be engaged with and then must provide their explicit informed consent to going off-grid and transitioning to a SAPS.
- For this to happen they must first have the required footprint available on their property to accommodate the solar panel array and ancillary equipment required for a SAPS and provide consent to use this space. Our current experience with targeted SAPS customers is that 31% agree to an off-grid SAPS solution when approached.
- SAPS are a bespoke solution, suitable for certain locations such as a long rural powerline i.e.: > 1km in length supplying 1-2 customers, and/or where there are known reliability or access issues. In those cases, they may be the most economically efficient solution.
- Given the relatively high cost to establish a SAPS, the number of locations within the new high bushfire risk zones where SAPS would be a credible substitution option is small, addressing < 1% of the total targeted powerline length where enhanced vegetation standards are required.
- Project analysis showed several SAPS sites with a positive NPV. This analysis is independent of the funding already allocated for SAPS in the current regulatory period.
- Essential Energy will remove the potential for cost duplication from any location overlap between our approved SAPS program and the newly identified high bushfire risk zones. Furthermore, Essential Energy is committed to maximising the installation of SAPS where prudent and efficient to do so, ensuring the economic analysis for the SAPS captures the cost savings from the avoided vegetation works and the powerline maintenance activities that the removed powerline would have otherwise incurred.

Our initial analysis has revealed a maximum of 208 potential SAPS projects in P1 areas. The resultant maximum impacted line length is 214kms *if all projects were to proceed* and *all projects were in non-clear-*

to-sky locations. Using our recent experience where only 31% of identified customers may agree to go off-grid and convert to a SAPS, the maximum project impact from SAPS would be:

- Total P1 non-CTS line length; 3,849kms
- Total new P1 area line length; 7,508kms
- Maximum identified length of SAPS (from the 2024-29 price determination) in new P1 areas; 214kms
- % customer agreement for an off-grid SAPS solution; ~31%
- Possible impact of SAPS on this project; 214km x 31% = 66kms

Therefore, we estimate that 66kms of powerlines out of a total affected line length of 3,849km may be potentially removed from this project due to SAPS projects proceeding, or < 1% of the total project scope.

Thus, the SAPS option will have a negligible to small impact on the overall project scope and has therefore been discounted as a viable non-network solution in replacing the need to undertake the proposed vegetation CTS works in the new P1 areas.

7. Economic Assessment

Our economic assessment for this final report is based on existing vegetation contract rates with considerations for expected price changes over the eight-year transition. Essential Energy engaged an independent consultant to provide an assessment of Essential Energy's future vegetation management costs. The existing vegetation contracts will be renewed on or before the 1st July 2026. The outcomes from this market process may materially impact the vegetation treatment costs incurred by Essential Energy.

Program costs

This program targets the safety and the reliability elements of the NEO, meaning that these two elements form the basis of the economic benefits our customers will gain from this proposed expenditure.

In this section the economic costs are first discussed followed by the economic benefits, and then a summary of the net economic benefit to our customers is presented.

Contingency has been calculated in alignment with guidance from the Association for the Advancement of Cost Engineering 96R-18 cost estimate classification system. It has been applied only to cost line items where Essential Energy has limited control over the quantities, unit cost and/or complexity of the work.

The economic cost of the proposed program are the financial costs associated with the program delivery.

Vegetation costs

The financial costs of the vegetation treatment have been estimated using two approaches.

1. **Unit rate cost (cost model A)**

The purpose of this cost model was to establish the cost of undertaking the vegetation treatment using available cost data. i.e. actual costs from the VMA pilot, adjusted for estimated changes over the duration of the project.

This method weighted each VMA by vegetation treatment complexity and extrapolated the average unit rate costs based on these factors.

This method yielded a total vegetation treatment cost of $58.4 million.

2. Data science methodology (cost model B)

The purpose of this cost model was to provide a validation check to cost model A.

A machine learning approach based on random forest regression was used. Random forest is a supervised learning method that can handle both numerical and categorical data, as well as nonlinear relationships and interactions between features.

Data sets were identified that have an influence on the cost of undertaking vegetation works. These include vegetation density, proximity to roadways, roadway speed limits, and terrain characteristics.

The output of this cost model yielded a total vegetation treatment cost of $51.0 million.

NOTE: these costs are for the underlying *vegetation treatment* aspect of the overall program of work (tree removals and trimming) and exclude additional costs of the program identified below.

Vegetation cost model comparison & scenario development

The cost models are within 15% of each other, providing a good level of confidence for the magnitude of the cost that was established using cost model A.

NOTE: Cost model A will be used to determine the final program cost.

Table 2 shows the high-level expected phasing of the program, and Table 3: 'Summary of Incremental CAPEX', includes the expected incremental cost of this CTS vegetation cutting.

Table 2: Proposed Vegetation Transition

	CURRENT REGULATORY PERIOD					NEXT REGULATORY PERIOD				
Fiscal year	FY25	FY26	FY27	FY28	FY29	FY30	FY31	FY32	FY33	FY34
Transition	Yr 0	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Program completed
Completion	2%	5%	10%	15%	15%	15%	15%	15%	8%	

Avoided capital expenditure (capex) due to SAPS

As outlined in Section 6 above, we are anticipating that there are some locations that are newly classified as highest bushfire risk, that are appropriate for a SAPS. If a SAPS is installed and the powerline grid connection is removed (following agreement with the customer) it means that there are less powerlines that need this CTS treatment. We have reviewed the new P1 areas and updated our SAPS program (we have been funded for up to 400 SAPS over 2024-29) to include the new CTS treatment costs. This review indicated that there is approximately 66km (pending customer acceptance of a SAPS) of new P1 network length where CTS work would not be needed, due to a SAPS installation.

Further, once the powerlines have been removed across the 66km of network, this network no longer requires ongoing capital investment. This avoided capital investment has also been considered in the calculation of the net benefits of this option. The incremental avoided cost is shown in Table 3.

The cost of the SAPS installations is completely excluded from Table 3 incremental costs, thereby providing further benefits in selecting Option 3 - in addition to it already providing the highest NPV outcome (see Table 5 below). This is because funding for up to 400 SAPS was already included in Essential Energy's 2024-29 Determination. We have also excluded the SAPS installation costs for the remainder of the project duration (through to FY33), on the assumption that the SAPS program is likely to be assessed at the next reset as an ongoing efficient investment solution. The SAPS forecast to be needed as part of this project, will form part of the larger SAPS program to be included in our 2029-34 Regulatory Proposal.

Planned outage costs

Clearing overhanging vegetation above powerlines will require network outages whist the work is being undertaken. The estimated additional number of outages over the eight-year transition to facilitate the CTS vegetation treatment work is 1,348.

The costs associated with planned outages for vegetation work are broadly made up of two components:

1. Isolation and restoration switching activities (labour) undertaken at the start and end of each planned outage.
2. Access permit holders (labour), onsite for the duration of each outage, who must maintain regular visual and audible contact between the Access Permit (AP) recipient and those signed onto that AP.

These additional outages are not able to be absorbed and facilitated with current resource constraints.

There are also other costs associated with working near the network to treat vegetation, that include the use of live-line crews, managing complaints, obtaining a notice of entry (including at times engaging the police) and managing incompatible tree removal refusals.

The extra cost of facilitating outages and vegetation trimming near the network is detailed in Table 3**.**

Other Costs

Additional risk treatment during the transition period

During the proposed 8-year transition program, the existing cyclic vegetation management program must continue in parallel to the CTS transition program. Additional assurance controls will be utilised to ensure both the cyclic cutting program and the CTS transition cutting program are meeting the stated regulatory requirements and project performance milestones. These will include:

- Additional aerial and/or ground-based inspections to identify encroaching vegetation and to validate completed works. Costs to undertake this additional assurance activity will be $200,000 per year for the 8-year duration of the project. Total cost $1.6m.
- Advanced digital twin modelling techniques to model risk associated with vegetation contacts. This will assist with the prioritisation of risk mitigation activities that are required to occur throughout the transition. Risk analytics will be supported by strategic digital twin data acquisition at intervals throughout the transition. An interval approach with digital data acquisition activities occurring in year zero, year three and year six of the transition, will enable risk differentiators, such as growth rate and site access, to be monitored and treatment plans to be modified as necessary.

The extra cost of acquiring and processing this digital data for risk assurance purposed during transition is detailed in Table 3**.**

Internal labour

The transition cutting project will occur over an 8-year period and will be run separately but concurrently with the cyclic vegetation inspection and cutting program. Given the complexities and logistics associated with this project, a small, dedicated team of ten full time employees, will be required to manage the works.

The team is made up of three Management staff: A Planning Manager, Compliance Manager and Reporting Manager.

The remaining six full-time staff will form the delivery team. This will consist of five Technical Officers to co-ordinate outages, notices of entry, environmental approvals and resolve complex customer interactions, and one Environmental Specialist to deliver the environmental approvals and aboriginal heritage assessments.

Lastly, a resource will be engaged to successfully deliver the Communications and Stakeholder Engagement Plan across the 8 year transition period.

This extra staff cost for the 8 years of the transition project is detailed in Table 3.

Environmental approvals

The upgrade of 7,508km of network to P1 compliance will require tree removals and, in some cases, where considerable tree removal outside the previously cleared powerline corridor is required, an Environmental Impact Assessment (EIA) will need to be prepared to meet statutory obligations.

In such situations, the EIA, most likely in the form of a Review of Environmental Factors (REF), will likely need to be supported by an ecological impact assessment. Depending on the level of existing disturbance, landscape characteristics, and location relative to known Aboriginal objects and places, an Aboriginal heritage assessment may also be required. Our estimate of incremental cost is shown in Table 3.

Other third-party costs

There are other third-party costs associated with this program of work. Essential Energy has already incurred some fees, and over the course of this project there will be further costs incurred.

These costs to date have included legal advice to modify existing vegetation contracts so the additional CTS vegetation treatment could begin in FY25, and reviewing of various documents for regulatory purposes.

Essential Energy sourced an independent industry review of the vegetation management sector and will require a third-party to provide further analysis of the sector to support the contract renewals in light of this CTS work.

In addition, there will be costs associated with community engagement and social licence, such as sponsorship and advertising costs that will support the proactive community engagement necessary for the vegetation work.

See Table 3 for the additional costs of this work.

Additional operating expenditure (Opex) to maintain CTS corridors

The upgrade of 7,508km of network to P1 compliance will incur an incremental cost to maintain the CTS corridors once they have been established. This extra cost has been derived from existing VMA contract rate data and is detailed in Table 4: 'Summary of Incremental OPEX' for the period of the transition project.

Avoided OPEX due to SAPs

Our assumption of being able to roll out SAPS in some of these newly identified high bushfire risk areas, means that consequently, there should be lower ongoing opex. We will not need to maintain the removed powerlines, and we will not need to undertake cyclical vegetation maintenance around the removed powerlines. The detail of this opex cost saving, due to the removal of powerlines when these SAPS are installed, is provided in Table 4.

Summary of Incremental Expenditure (FY25 - FY33)

Table 3: Summary of Incremental CAPEX

CAPITAL EXPENDITURE (CAPEX) *COSTS ARE IN FY$25 DOLLARS*	
Vegetation transition cutting (creating CTS corridors)	58.4m
Avoided CAPEX due to SAPS installations	($2.2m)
Network outage costs	$9.3m
Additional aerial and ground-based inspection assurance	$1.6m
Additional digital data acquisition	$6.4m
Internal labour *(Vegetation delivery staff, Environmental approvals & Community consultation)*	$13.7m
Environmental assessments	$2.3m
Other third-party costs	$0.5m
Total CAPEX	**$90.0m**

Table 4: Summary of Incremental OPEX

OPERATING EXPENDITURE (OPEX) **COSTS ARE IN FY$25 DOLLARS*	
Maintaining clear-to-sky corridors once established	$9.4m
Avoided OPEX due to SAPS installations	($0.7m)
Total OPEX	**$8.7m**

Defining Benefits

The economic benefits attributable to the proposed expenditure are the avoided economic costs relating to the risks that would be mitigated by undertaking this work.

There are two classes of benefits addressed by this project: the mitigated safety risk and the mitigated network reliability risk.

The market will benefit from less power supply interruptions when both risks are treated. Specifically, regarding the mitigated safety risk, it should be highlighted that by preventing a network-initiated fire, not only is the network asset safer and more reliable but, by treating this safety hazard (network-initiated fire), the surrounding assets are also less likely to fail/experience supply interruptions.

1. Mitigated safety risk

The mitigated safety risk includes a valuation of the quantifiable tangible and direct community impacts from a powerline-initiated bushfire, being injury and/or life loss and property and asset loss. This has been established using the University of Melbourne Phoenix RapidFire bushfire simulation model. The model determines the consequence of a bushfire and provides a quantified value of the loss and damage arising from a powerline-initiated bushfire should one arise from the Essential Energy network.

Separately, we have developed models to determine the likelihood of vegetation contact with Essential Energy powerlines as well as the effectiveness (likelihood reduction) of CTS cutting standards and/or the deployment of HVCC or SAPS.

Combining these models provides a quantifiable safety risk reduction benefit for the deployment of the assessed options. This will, in turn, reduce the need for network interruptions.

2. Mitigated reliability risk

The mitigated reliability risk is an assessment of the customer impact of power outages that would be *avoided* due to the enhanced vegetation clearing standards applied in the new P1 areas.

Like the safety risk benefit assessment, the vegetation contact model (likelihood) has been used to inform the projected avoided outages, whilst the consequence of the avoided outages uses the AER-provided Value of Customer Reliability (VCR) metric.

Combining these two benefits provides a quantifiable reliability risk reduction benefit for the deployment of the assessed options, contributing to 'changes in involuntary load shedding and customer interruptions caused by network outages, using a reasonable forecast of the value of electricity to customers. That quantified benefit for each option appears in Table 5.

Bringing together Costs and Benefits

To determine which option delivers the greatest value, a Cost Benefit Analysis has been conducted for each.

- **Option 1** Undertake standard clear-to-sky (CTS) cutting treatment of vegetation corridors in all newly identified bushfire priority zones
- **Option 2** CTS treatment in most newly identified bushfire priority zones, supplemented with the targeted installation of some high voltage covered conductors (HVCC)
- **Option 3** CTS treatment in most newly identified bushfire priority zones, supplemented with the targeted installation of some Stand-Alone Power Systems (SAPS)

The results below show the alternative costs of the credible options to complete the project through to FY33 and demonstrates that Option 3 has the highest Net Benefit and Benefit Cost Ratio of the three options over the 20-year time horizon used for NPV analysis.

Table 5: Summary of credible options

Option	Description	Net Project Capital Cost ($m nominal)	Net Project Operational Cost ($m nominal)	Present Value Benefits ($m FY25 real)	Present Value Costs ($m FY25 real)	Present Value Net Benefit ($m FY25 real)	Benefit cost ratio	Rank
1	Clear to Sky	104.3	11.0	342.1	114.3	227.9	3.0	3
2	Clear to Sky with some HVCC	109.5	10.9	357.6	118.1	239.5	3.0	2
3	Clear to Sky with some SAPS	115.3	10.2	366.2	117.7	248.5	3.1	1

Option 2 and Option 3 provide better overall risk reduction benefits compared to Option 1 due to the comparable risk reduction effectiveness where HVCC or SAPS would be deployed.

Given the potential significant harm from a bushfire it is not unusual to see relatively high benefit cost ratios from bushfire prevention related Cost Benefit Analysis. As an example:

- Deloitte Access Economics[6] (2014) found a Benefit Cost Ratio of 6.0 for fuel reduction measures in the Blue Mountains to avoid a bushfire.
- Benetton, at al (1997) found for Victoria "… for $1 of public resources allocated to the Fire Management Program, the State benefits by $22 in terms of assets not destroyed by wildfire". [7]

Conclusion

The preferred options to transition the new highest risk bushfire areas to an enhanced vegetation management standard is to undertake a combination of CTS treatment supplemented with selective retirement of bare overhead wires and the installation of SAPS in line with Option 3.

The application of SAPS would occur on a site-specific basis *where it is economically more efficient to deploy this option* and where the customer has agreed to convert to a SAPS solution.

8. Completion of the RIT-D process

Essential Energy is publishing this final project assessment report in relation to the transition of required vegetation management standards to the new bushfire priority zones – it is the last stage of the RIT-D process.

Essential Energy sought feedback on 23 July 2024 from stakeholders on our preferred option via the Draft Project Assessment Report, and our non-network options screening notice. This included registered participants, the Australian Energy Market Operator (AEMO), non-network providers, interested parties and persons on our demand side engagement register. Our Customer Advocacy Group was also provided with the link to the publicly available RIT-D documents for this project. Submissions were due by 3 September 2024.

No submissions were received over the six-week consultation period.

Contact details

Any enquiries regarding this Final Project Assessment Report should be directed to Alex Bardon or Pip O'Donnell at reginvestment@essentialenergy.com.au.

[6] https://ausfpa.com.au/wp-content/uploads/2016/01/AFPA-DAE-report-Amended-Final-2014-05-27.pdf, Table 7.4, p.44

[7] "An economic evaluation of bushfire prevention and suppression in Victoria. Working paper" 9703: Julia Bennetton, Paul Cashin, Darren Jones and James Soligo – Performance Evaluation Division, Department of Natural Resources and Environment (Vic) June 1997 ISBN 0 7306 6711 1. Also in Australian Journal Of Agriculture and Resource Economics, $2:2 Pp 149-175

9. Glossary

ACRONYM	FULL NAME
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
CAPEX	Capital Expenditure
CPA	Contingent Project Application
CTS	Clear To Sky (vegetation removal)
DAM	Digital Asset Management
DPAR	Draft Project Assessment Report
FPAR	Final Project Assessment Report
HVCC	High Voltage Covered Conductor
IPART	Independent Pricing and Regulatory Tribunal
MA	Maintenance Area
NEO	National Electricity Objectives
NER	National Electricity Rules
NPV/C	Net present Value / Cost
OPEX	Operating Expenditure
P1	Priority 1 Bushfire risk area
P2	Priority 2 Bushfire risk area
P3	Priority 3 Bushfire risk area
P4	Priority 4 (Urban) Bushfire risk area
PSBI	Pre-Summer Bushfire Inspection
REFCL	Rapid Earth Fault Current Limiters
RIT-D	Regulatory Investment Test – Distribution
SAPS	Stand Alone Power System
VMA	Vegetation Management Area

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