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Assessing and mapping the DER hosting capacity of energy networks

Techno-economic comparisons of future distribution network upgrade strategies to address thermal and voltage issues

Final report

Assessing and Mapping the DER Hosting Capacity of Energy Networks: Optimised Zone Substation MV Voltage Management to Increase Distributed Energy Resources (DER) Hosting Capacity

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The authors of this report would like to respectfully acknowledge the Traditional Owners of the ancestral lands throughout Australia and their connection to land, sea and community. We recognise their continuing connection to the land, waters and culture and pay our respects to them, their cultures and to their Elders past, present and emerging.

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Contents

List of Acronyms

ABS – Australian Bureau of Statistics

AEMO – Australian Energy Market Operator

AER – Australian Energy Regulator

BAU – Business as Usual

BESS – Battery Energy Storage System

CECV – Customer Export Curtailment Value

CSIRO – Commonwealth Scientific and Industrial Research Organisation

DAPR – Distribution Annual Planning Report

DER – Distributed Energy Resource

DNSP – Distribution Network Service Provider

dSTATCOM – Distribution Static Synchronous Compensator

EV – Electric Vehicle

HEMS – Home Energy Management System

ISP – Integrated System Plan

LDC – Line Drop Compensator

LVR – Low Voltage Regulator

MEN – Multiple Earthed Neutral

NER – Neutral Earthing Resistor

OLTC – On-Load Tap Changer

PV – Photovoltaic

QDSL – Quasi Dynamic Simulation Language

STATCOM – Static Synchronous Compensator

Executive Summary

The purpose of this report is to estimate to a reasonable depth of detail the comparative costs of different solution pathways for rectifying network issues that will arise in typical Australian distribution networks as the adoption of rooftop photovoltaic generation and other technologies continues to increase. To achieve this, the network upgrade costs have been measured more precisely than in the similar RACE for 2030 project that preceded this one. In this study, the volumes and costs of each type of solution required to achieve specific performance targets from present day until 2050 has been identified for three different solution pathways. The effectiveness with which BESS technologies can replace traditional network upgrade projects without increasing overall network upgrade costs are identified.

So that the cost of different upgrade strategies for a typical zone substation area can be precisely quantified, a distribution power network load flow model representing a zone substation area in suburban Brisbane is utilised in this study. This model contains accurate representations of the low voltage networks connecting over 13000 customer connections as well as the volt-watt and volt-var algorithms that would be acting on the output of their existing solar inverters and four-wire modelling of the LV distribution lines that connect them to the wider network. Growth in both rooftop PV and electric vehicles that is equivalent to the average of the two fastest growing scenarios from the most recent AEMO Integrated System Plan is applied to the model across five-year intervals out to 2050.

The modelled growth in PV generation and electric vehicles affects substantial change on the load profile for the zone substation that was modelled. The midday load trough in the modelled zone substation area on a typical spring day with high solar irradiance decreased from approximately -8.3 MW to approximately -54.8 MW throughout the study period due to solar PV growth. The height of the evening peak on a spring night increased from approximately 20.9 MW to approximately 42.7 MW throughout the study period due to increased electric vehicle charging. The typical height of this evening peak would be likely to be greater on a summer night following a day with high solar irradiance as the increased residual temperatures will imply higher air-conditioning use in the evening and thus higher overall load. The depth of the midday trough on days with high solar irradiance is expected to be greater in spring and autumn in general however because the milder temperatures imply less air-conditioning usage and thus less load to absorb the excess solar generation.

It is found in the central case for the study that costly upgrades to the zone substation and MV network can be avoided if sufficient BESS capacity is installed in either the MV or LV sections of the network. This also yields significant savings in both 2045 and 2050. Due to the fact that the BESS solution pathways manage to delay costs more than the traditional network upgrades solution pathway would, NPV analyses show present-day benefit from committing to either of them, with the LV BESS solution pathway exhibiting the lowest present-day cost.

The variations that would be applicable to the costs for the solution pathways simulated were also estimate for a variety of alternative cases. In the first of these, behind the meter BESS installations were expected to grow and be utilised by customers in a reliable fashion each day and the load profile created by EV charging was assumed to be partially smoothed out by a time of use tariff. The second of these two assumptions effectively provides partial breaking to the growth of midday

excess PV generation; the first of them however does not because typical behind the meter BESS installations are expected to be fully charged by mid morning when the solar peak occurs. The costs for the MV and LV BESS solution pathways scale with both the energy and peak power requirements of the emerging thermal constraints, while the costs of the traditional network upgrades scale only with the peak power requirements of the thermal constraints. The reductions in cost that are seen in this variation case are therefore larger for the MV and LV BESS solution pathways than they are for the traditional network upgrades solution pathway.

An upper limit of 100 kW of BESS capacity per LV feeder was used in most cases investigated. A capacity limit such as this would ensure the DNSP that malfunctioning of BESS control systems would be unlikely to inadvertently produce thermal overload of the LV feeders. In the second variation case investigated, it was found that costs could be reduced to some degree in the LV BESS solution pathway if this BESS capacity limit were removed. The practical upper limit on how much BESS capacity could be installed on any one LV feeder without producing too much risk of accidental overload due to control system malfunction is an important consideration, however. At any rate, this variation case indicates that the cost saving that is realised by the LV BESS solution pathway over the MV BESS solution pathway because of the fact that it can displace traditional network upgrades to LV areas can be made larger if the amount of BESS capacity permitted on each LV feeder is made larger.

In another case identifying the extent to which network upgrade costs would increase if voltage magnitude compliance were also enforced, the costs of the MV BESS and traditional network upgrades solution pathways were both found to increase by more than the LV BESS solution pathway. This finding is attributable to the fact that STATCOMs are significantly cheaper on average than traditional LV area splitting and re-conductoring methods for rectifying LV network voltage issues. The final two cases studied explored the extent to which the network upgrade costs would change if the type of conductors in the zone substation area were all overhead lines or all buried cables, respectively. It was identified that the cost competitiveness of the BESS solution pathways with the traditional network upgrades solution pathway would not be as strong if applied across a zone substation area composed entirely of overhead lines. For a network composed entirely of buried cables however, the LV BESS solution pathway would be likely to remain cheaper than the other two solution pathways for a substantial period beyond 2050, if not indefinitely. This is attributable to the fact that the ability of the LV BESS solution pathway to displace LV area splitting upgrades involving buildout of MV buried cables would create a substantially larger benefit in this case.

The paces at which the cost curves for both MV and LV BESS solution pathways grow from 2045 to 2050 however imply that they would eventually reach higher costs than a traditional network upgrades strategy at some point beyond 2050. When this would occur is difficult to predict however, especially given that the zone substation upgrade cost has a large uncertainty of ±30% associated with it. Furthermore, the underlying upgrade costs in all three solution pathways are identified as exhibiting additional nonlinear dependencies on the severity of the constraints being alleviated, which tend to worsen year on year. These additional nonlinearities lower the robustness of costs estimates for the years beyond 2050 further still. Nevertheless, linear extrapolation is used to estimate the years at which the cost curves for each of the BESS solution pathways would overtake the cost curve for the traditional network upgrade solution pathway; these calculations are performed simply to demonstrate sensitivities to the different assumptions used in the different cases studied. They indicate generally that the costs for the LV BESS solution pathway would be likely to undercut those for the traditional network upgrades pathway for longer than the costs for the MV BESS solution pathway would.

An additional sensitivity study was also performed in which the assumed rate of decline of battery costs in the future was varied by ±20%. The year at which the linearly extrapolated costs for the LV and MV BESS solution pathways would overtake the linearly extrapolated costs for the traditional network upgrades solution pathway for the central case of the study was then re-estimated. It was found that the LV BESS overtaking year is more sensitive to assumed battery costs than the MV BESS overtaking year, which is attributable to the fact that the latter solution pathway uses more traditional network upgrade solutions and less batteries than the former solution pathway does. These sensitivities were however relatively small for both of the BESS solution pathways; +2/-3 years for the LV BESS solution pathway and +1/-2 years for the MV BESS solution pathway. The fact that both solution pathways exhibit relatively minor variation in their late-stage cost curves in response to such significant variation of the battery cost assumption indicates that the findings of this study are relatively robust to inaccuracies in future battery cost estimates.

In any case, exceedance of traditional network upgrade costs would only occur in the MV and LV BESS solution pathways if growth in rooftop PV were to continue at the same rate as it does throughout the ISP prediction period. The rate of PV growth that is realised in practice can be expected to plateau at some point in the future, either due to limitations in available roof space or the growth in efficiency gains for the PV technology itself. Indeed, such a plateau could even occur before 2050. If it is assumed that this plateau is unlikely to occur before 2042 however, then the MV and LV BESS solution pathways can be seen as providing a good hedging strategy against the expensive upgrades that would need to occur in a traditional network upgrades solution pathway.

Aside from the required thermal and voltage issue rectification created by each of the three solution pathways, the MV and LV BESS solution pathways also provide several other additional system benefits that it was not possible to estimate the value of in this study. These include greater improvements in residual thermal and voltage magnitude issues, reduced solar inverter active power curtailment and reduced active and reactive power losses throughout the network during midday high solar conditions. Such benefits would provide additional value for both DNSPs and TNSPs as they would naturally propagate upward from the distribution networks into the transmission networks. The BESS solution pathways would also provide network security, reliability and stability benefits to the NEM as a whole as they would be removing excessive solar generation that would otherwise not be consumed by the relatively low levels of midday load across the wider network. Furthermore, the inverters used to interface the BESS installations to the distribution network could also provide harmonic filtering and voltage unbalance correction services whenever their capacities were not being fully utilised for battery charging or discharging. Operational benefits such as these could be highly valuable; estimating their value was beyond the scope of this project however.

Overall, the findings of the study indicate that the ability of the BESS solutions to displace multiple traditional network upgrades simultaneously gives them a cost advantage that is likely to last far into the future. Even if practical space limitations render some combination of the three solution pathways necessary, the substantial benefit that can be realised just by avoiding the costly zone substation upgrade should be sufficient justification for applying at least the amount of BESS capacity that makes realisation of this benefit possible for a large number of both planned and existing zone substations. Furthermore, the network security, reliability and stability benefits that would be provided to the NEM by either of the BESS solution pathways as a result of their positive effect on midday minimum load conditions was not costed in this study and would be likely to be substantial. An economic assessment of the extent of these wider system benefits that could be provided by BESS technologies should be performed by larger organisations with greater available resources, such as the AEMO and the CSIRO, that are responsible for performing research which in turn can inform future policies that will influence the trajectory of the Australian power industry.

1 Introduction

1.1 Study objectives and overview

In a previous RACE for 2030 project, the extent of overvoltage issues caused in typical Australian distribution networks by excessive small-scale rooftop solar generation was investigated using a highly detailed and large-scale network power flow model. The initial load and generation profiles in this model were baselined against real-world data and four-wire neutral modelling was also included for the low voltage feeders. Expected growth in rooftop solar and electric vehicles was then modelled so that the rate at which the overvoltage issues would worsen in the future could be assessed. An additional finding in this previous study was that thermal overloads of distribution transformers and buried and overhead lines would also emerge at rates similar to the overvoltage issues. The intention of the present study is to continue the investigations that commenced in the previous study by assessing the cost-effectiveness of different strategies for solving the voltage and thermal issues that will arise in typical Australian distribution networks as DER penetration levels continue to increase. The costs associated with both rigid adherence to traditional network solutions and financially considered integration of the STATCOM and BESS technologies into the suite of solutions will be estimated using the same detailed power system model developed in the previous project.

The focus of the present project will pick up where the last one left off. Specifically, where the previous project compared the effectiveness of traditional and STATCOM-based voltage management solutions in a limited number of LV areas; in this study the effectiveness of different types of solutions for both thermal and voltage management problems in the entirety of a zone substation area will be investigated. Furthermore, the effectiveness will be quantified more precisely by measuring the volume and cost of each type of solution that would be necessary to achieve specific performance criteria for current and voltage compliance.

This study employs research-supported forecasts to produce estimates of the concequences of continued growth in DER penetration that will be typical for Australian suburban distribution networks. It also estimates the costs of competing solution pathways for dealing with these issues. It is intended that it will provide a reasonably realistic and generic scenario that will help network planners to understand how to chart a least cost path for future network development towards 2030 and beyond.

1.2 Background

The energy transition will result in increased electrical load across Australian power networks. This will occur as a result of the electrification of various energy-consuming systems currently run using fossil fuels in industrial plants, commercial facilities and residential premises throughout the nation. This electrification is being driven by the need to limit global climate impact by 2050. As a consequence, the Australian power industry is facing waves of technological changes that exhibit speed and depth not experienced since the inception of nation-scale expansion of electric power systems. In the coming years and decades, distribution networks in Australia will see such a volume of rooftop photovoltaic (PV) generation, electric vehicles (EVs) and other forms of distributed energy resources (DER) placed behind the meters of its customers that their performance mandates will change drastically. Smart meters will eventually be universally adopted, bringing with them transparency, accountability for network voltages and stronger compliance drivers. The roles of distribution networks will go from that of acting as one-way funnels for the passage of centrally generated, fossil fuel derived power to serving as bi-directional multi-lane highways for the transit of large volumes of locally produced renewable energy, as well as the consumption of this. The instantaneous power densities that will need to be permitted to flow through these networks will reach levels that this type of infrastructure was never designed for. Put simply; the emergence of large volumes of DER in Australian distribution networks will constitute such a significant expansion to the levels of performance required of these systems that the fundamental planning philosophies that they were designed and built with since early in the last century will need to be re-written.

Electrical conductors strung on poles and cable systems buried beneath the suburbs can facilitate the transit of only so much power before voltage limits and thermal limitations are encountered. Once they are, the traditional mitigation strategies in any power network are to re-build the circuit with a higher grade of conductor exhibiting a larger cross-sectional area, to upgrade the distribution transformer to one with a higher thermal rating and/or to split the circuit being served using more connections to the upstream network of a higher voltage. In cases where such solutions couldn't be implemented due to space constraints, the only option remaining would be to place limitations on the network capacity available to customers for import and export of renewably generated power. This is the intended function of Dynamic Operating Envelopes (DOEs) which have been the subject of much recent research e.g. [1]. In a future in which copious investments in DER have been made with the intention of offsetting carbon emissions, such limitations would translate into a considerable lost opportunity cost from an environmental perspective.

The only alternative technological avenue for solving the emerging thermal overloads in the distribution networks that doesn't also necessitate the curtailment of renewably derived energy is the use of energy storage. Furthermore, the only form of energy storage with the performance characteristics necessary to re-enable the capacities of the distribution networks is batteries. What typical size and distribution of batteries will achieve the most economic efficiency within the timeframe that they are needed is unclear, however. The upfront capital costs for battery energy storage systems (BESSs) are significant enough that investments in these from the majority of Australian household owners seems unlikely to occur within the short to medium term [2]. Intervention on the part of the distribution network service providers (DNSPs) charged with building, operating, and maintaining these networks will therefore be necessary. No clear roadmap as to the scale, distribution and timing with which installation of BESS devices will be needed has yet been identified. For DNSP planning departments, this reality renders the estimation and justification of the funding that they would need to carry out this extensive installation program highly challenging at present.

As the fleet of DER connected to the distribution networks is continuously bolstered and expanded upon, thermal capacity issues are not the only form of physical limitations that will be encountered. The magnitudes of network voltages will also encroach upon and exceed their statutory limits, resulting in accelerated degradation of consumer electrical appliances and spurious tripping of protection systems. In addition to this, the balance between the voltage vectors on the three phases of the system will degrade; this in turn will imply rapidly increasing power losses and poor utilisation of the network. As batteries are a direct current (DC) technology, BESS installations must include inverter systems to connect them to the alternating current (AC) power system.

Inverter devices can also be programmed so that they rectify the emerging voltage magnitude issues through the sourcing and sinking of reactive power. Furthermore, if they are specified to have four arms and connecting wires rather than three, they can also source and sink reactive power and even non-zero sub-cycle average active power in such a fashion that the network voltages could be rebalanced even when only an inverter and no battery is present. Such utilisation of inverter devices without batteries to regulate average network voltage magnitudes and/or voltage imbalances are generally referred to as static synchronous compensators (STATCOMs). On parts of the network in which voltage issues arise before thermal ones, initial investment in STATCOMs may be all that is needed at first. Investment in the larger expense for a battery can then be delayed until it becomes a necessity, and the investment profile associated with the upgrades of the network can be made more gradual and thus more economically sustainable.

While re-conductoring, transformer size upgrades and LV area splitting will be cheaper on a local basis, BESS installations can provide an additional advantage that these traditional network solutions cannot. Their cumulative absorption of active power would also serve to reduce the accumulation of midday excess solar generation on the zone substation feeding a given area, thereby postponing the timing of its eventual upgrade and providing a whole of system benefit. For distribution networks in urban areas where space is limited, the cost of such an upgrade would be considerable as expansion of the size of the existing site to accommodate larger transformers, busbars and switchgear would often not be feasible and thus the upgrade would generally involve creation of new substations in suburbs surrounding the overloaded area combined with extensive load transfers.

A comprehensive comparison between the costs of the traditional network upgrades and BESS solution pathways should therefore also account for the fact that the BESS solutions would be able to avoid the cost required to upgrade the zone substation for significantly longer. Whether or not this would mean that the overall cost required to support the distribution networks through the renewable energy transition using a BESS solution pathway would be lower than the overall cost required to do so with a traditional solution pathway instead is the primary question investigated in this report.

It is also important to note that traditionally, network businesses have not modeled the LV system. This has been the case because its original design was rooted in the assumption that it exhibits enough margin in capacity that future augmentations would seldom be required, which is often referred to as a “set and forget” design philosophy. This assumption held for approximately seventy years, but now unfortunately, the renewable energy landscape has rendered it fundamentally invalid and has resulted in a need for greater visibility of LV networks. Without that visibility, DNSPs are likely to respond to emerging customer complaints in a reactive manner, which sooner or later will lead to them becoming inundated with insurmountable volumes of issues needing urgent resolution. It is far more cost effective to consider what the future may bring and to proactively make the best and most appropriately timed decisions on how the network should be developed to handle the forecast growth in both load and solar PV generation.

2 Structure of the study

2.1 Scenarios simulated

In this study, simulations were carried out to characterise network thermal overload and voltage magnitude violation issues in four separate scenarios; a business as usual (BAU) scenario in which no remediation measures to deal with these issues were employed as well as three separate *solution pathways* in which remediation strategies were employed. For each of the solution pathway scenarios, cost curves were also estimated. Variations in these cost curves for several different *cases* were also estimated so that important underlying sensitivities could be identified. A description of each of these cases is given in the subsection that follows this one.

The timeframe over which the BAU scenario and three solution pathways were simulated was from 2025 to 2050 in intervals of five years, which corresponds to the regulatory control period over which DNSPs must submit new revenue proposals to fund additional network upgrades. One of the major features determining the overall cost of each of the cases investigated was the need to upgrade the zone substation itself, or conversely to avoid its upgrade. The strategy in how overload of the zone substation should be handled is the central feature that differentiates the three solution pathways that were investigated. Descriptions of each of the solution pathway are as follows:

1. Traditional network upgrades solution pathway – In this solution pathway, thermal issues in the LV networks were addressed using only LV area splitting upgrades, transformer size upgrades and re-conductoring. Overload of the zone substation throughout the midday period due to excess PV generation was rectified using a traditional zone substation upgrade at a cost of $50 million (AUD). In the case in which compliance with voltage magnitude limits was also enforced, voltage magnitude issues in the LV networks were rectified using whichever was found to be the cheaper adequate solution out of re-conductoring and LV area splitting.
2. LV BESS solution pathway – In this solution pathway, thermal issues in the LV networks were addressed using LV BESS installations wherever possible and LV area splitting upgrades, transformer size upgrades and/or re-conductoring where these options were necessary. Active power absorption from the LV BESS installations was used to avoid the cost of the zone substation upgrade throughout the study period of 2025 – 2050. In the case in which compliance with voltage magnitude limits was also enforced, voltage magnitude issues in the LV networks were rectified using whichever was found to be the cheaper adequate solution out of LV STATCOMs, re-conductoring and LV area splitting.
3. MV BESS solution pathway – In this solution pathway, thermal issues in the LV networks were addressed using only LV area splitting upgrades, transformer size upgrades and re-conductoring. BESS installations applied to the 11kV medium voltage (MV) feeders of the modelled area were used to prevent zone substation overload and avoid the cost of its upgrade throughout the study period of 2025 – 2050. In the case in which compliance with voltage magnitude limits was also enforced, voltage magnitude issues in the LV networks were rectified using whichever was found to be the cheaper adequate solution out of re-conductoring and LV area splitting.

2.2 Cases simulated

The first case investigated in the study was one in which it was assumed that the DNSP would only make investments to address thermal violations. There are two logical arguments for why this might occur in practice. Firstly, while violations of the mandated voltage limits do cause long-term damage to household appliances, reduction of rooftop PV active power output due to the action of the volt-watt and volt-var algorithms mandated in AS4777.2 and even disconnection of the solar inverters if the overvoltages persist for long enough; these concequences are not as immediately obvious as the wide-scale power outages that would result from thermal overloads of buried cables, OHLs and distribution transformers. As such, the latter are likely to cause more pressing operational issues that must be dealt with immediately when they arise. Secondly, although the Australian standard AS 61000 does obligate the DNSP to address voltages that violate specific limits, universal installation of smart meters in every home would be needed to measure and record these violations and this infrastructure has only been widely installed in the state of Victoria at present. It is therefore unknown when the network visibility and statutory requirements would result in financial penalties for voltage non-compliance that would eventually force the DNSPs to act. The increased network visibility that will accompany eventual smart meter rollouts in other states would give rise to stronger compliance drivers, but when this would occur is as yet not clear; the timing of this change cannot therefore be estimated with any confidence.

In the first case simulated, it was assumed that EVs would be charged in accordance with a typical profile that is indicative of convenience-based charging behaviour; the same profile that had been modelled in the previous project [3]. This profile reflects what is most convenient for the typical household EV owner, as they would be likely to want to charge their vehicle when they arrive home from work towards the end of the day. Two different EV charger sizes were assumed to exist; one more common type sized at 3.68 kW and another less common type sized at 7.36 kW. It was assumed that the former of these would be assigned to residential customers having only a single-phase connection while latter would be assigned to residential customers having a three-phase connection. For the purposes of this study, it was assumed that EV charging would only occur at households i.e. that commercial and industrial customers would charge their EVs elsewhere at depots or other larger charging sites. This assumption is reasonable for this study as the suburban area which is fed by the zone substation that has been modelled does not contain sufficient additional space for large EV charging depots.

The ISP also contains trajectories for the growth in behind-the-meter (BTM) BESS systems procured by individual households and businesses. If this growth were to be realised then it would be beneficial as far as the voltage and thermal compliance of the distribution networks is concerned, because it could serve to reduce the extent to which excess solar generation is driven back up through the network throughout the middle of the day. The difficulty with such a technology from a DNSP's perspective however is that it is controlled by the customer. Its assistance in managing network congestion cannot be relied upon; if customers use them with the simple goal of maximising their financial benefit, then the typical BESS installation is likely to finish charging by mid morning i.e. before the voltage and thermal issues introduced by PV generation are at their worst. This could potentially be rectified if contractual arrangements are made with customers to procure network services from the BTM BESS installations. Depending on what customers come to expect as due compensation however, such contractual arrangements may not produce a cost-effective solution to network issues. The growth in BTM BESS installations cannot therefore be relied upon as a remediation measure for emerging thermal and voltage constraints in the distribution networks due to the simple reason that DNSPs will not be in control of them. So that the trends in the emergence of thermal violations simulated in this study would be conservative, BTM BESS installations were therefore not included in the first case investigated in this project. Other tariff mechanisms, vehicle to grid discharging technology, EV reactive support services, home energy management systems (HEMS) that automate demand side management using smart appliances and underlying residential and commercial/industrial load growth were also omitted based on similar reasoning.

In case 1, LV BESS installations were applied to alleviate thermal overloads of distribution transformers, buried cables and OHLs in those LV areas where such issues were identified only if 100kW or less were needed on any one LV feeder to achieve this. Wherever more LV BESS power capacity would be required, LV area splitting, and transformer size upgrades were applied as in the traditional network upgrades solution pathway. This conservative limitation on LV BESS capacity was assumed because of the practical possibility that the controllers of such installations might malfunction and cause these devices to inject large currents at the wrong time, thereby potentially worsening the thermal overloads that they are intended to prevent, even if only for brief periods of time. Such malfunctions may also cause unwanted equipment damage and/or spurious protection system operation. The effect of LV BESS installations in the second solution pathway can be described as *displacing* traditional network solutions to thermal issues wherever this is achievable without aggregating too much BESS capacity on any one LV feeder.

Two additional variations on the first case were also investigated. For the first variation, referred to as case 1a, it was assumed that a partially successful time-of-use (TOU) tariff had been implemented by the DNSP, resulting in an alteration to the typical charging profile adhered to by each EV owner. In this altered charging profile, charging during the solar peak at noon was doubled from what it had been previously, while the charging during the evening peak was reduced significantly.

The second variation on the first case investigated in this project, referred to as case 1b, was one in which the 100-kW restriction on LV BESS capacity per LV feeder was relaxed. Relaxation of this limitation allowed for a larger number of the traditional network solutions applied in the first solution pathway to be displaced by LV BESS installations. However, not all traditional network solutions that could theoretically be displaced were displaced. Further details on how this variation on case 1 was implemented will be discussed later in this report.

A second case was also investigated in which it was assumed that the DNSP would make additional investments to ensure that voltage magnitude issues would also be rectified. LV STATCOM devices were installed in the LV BESS solution pathway, while traditional network upgrade techniques were used to address these additional constraints in both the traditional network upgrades and MV BESS solution pathways. Note that no MV STATCOMs were used to address voltage constraints in the MV BESS solution pathway in this case because the extent to which STATCOMs can regulate voltage is proportional to the Thevenin equivalent impedance that is presented to them by the rest of the network at their point of connection. The Thevenin equivalent impedances seen from connection points in the LV networks are significantly higher than the same at any connection point in the MV networks in general, implying that a significantly greater amount of STATCOM capacity would be needed to achieve the same degree of voltage control from devices connected in the MV networks as devices connected in the LV networks. MV STATCOMs do not change the range of voltage drops that are imposed by the load on the LV system; they merely affect a change in the range of voltage drops on the MV system which carries through to the LV networks.

Finally, cost curves were also estimated for third and fourth cases in which all MV and LV lines in the network were assumed to be OHLs and buried cables respectively. The cost curves were estimated in these last two cases without additional simulations; instead, representative average costs calculated for upgrades in case 1 and assumed growth curves in LV and MV network upgrades were utilised. The details for the processes used to estimate the upgrade costs in cases 3 and 4 will also be explained later in the report.

The variety of cases investigated in this project is summarised in **Table 1**.

Table 1 – Description of cases investigated in this study

	Case description
Case 1	Case with only thermal violations remediated
Variation Case 1a	Variation case in which the EV charging curve is augmented due to a time-of-use tariff intended to incentivise more charging in the middle of the day and BTM battery growth from the ISP is also incorporated
Variation Case 1b	Variation case in which limitation on BESS capacity per LV feeder to 100 kW is lifted
Case 2	Case with both voltage and thermal violations remediated
Case 3	Case in which all LV and MV lines were assumed to be OHL
Case 4	Case in which all LV and MV lines were assumed to be underground cables

Not all cases were simulated in all scenarios. In the BAU scenario, simulations were executed only for case 1 and variation case 1a. Simulations were executed for variation case 1b only in the LV BESS solution pathway as this variation case is defined solely by an alteration to BESS installation limits per LV feeder. Simulations were not executed for case 2 in the BAU scenario because the distinction between case 2 and 1 is merely a variation on which constraints warrant the application of remediation strategies and the BAU scenario is defined by having no remediation strategies applied in general. Cases 3 and 4 were not simulated; costs for these were estimated using averages from case 1. The subsets of cases simulated or for which costs were estimated in each scenario are detailed in **Table 2**.

Table 2 – Subsets of cases simulated, or for which costs were estimated, in each scenario

	BAU	Traditional Network Upgrades Solution Pathway	LV BESS Solution Pathway	MV BESS Solution Pathway
Case 1	Simulated	Simulated	Simulated	Simulated
Variation Case 1a	Simulated	Simulated	Simulated	Simulated
Variation Case 1b			Simulated	
Case 2		Simulated	Simulated	Simulated
Case 3		Costs estimated	Costs estimated	Costs estimated
Case 4		Costs estimated	Costs estimated	Costs estimated

2.3 Report structure

The structure of the remainder of this report is as follows. In section 3, the forecasted growth trajectories used for PV and EV technologies are detailed and justified, as is the growth trajectories in BTM BESS and alterations to the charging profiles for EVs for variation case 1b. Following this, details of the modelled zone substation area as well as how the simulations were executed and the outcomes of simulations of case 1 and variation case 1a for the BAU scenario are presented in section 4. The methodology with which the upgrades in each of the three solution pathways were modelled are then explained in section 5, while the assumptions upon which cost calculations for the solution pathways were founded are stated and justified in section 6.

In section 7, the upgrade outcomes for the solution pathways under all applicable cases are shown and cost curves for each are depicted and briefly discussed. Network performance metrics other than the targeted thermal overload and voltage magnitude limit compliance targets and upgrade cost outcomes that are found to accompany each of the solution pathways are shown at the end of section 7. Finally, the implications of and inferences that can be made from all of the results presented in the preceding sections are discussed in section 8 and the report is concluded in section 9.

3 Forecasts

3.1 Input sources

As in the previous RACE for 2030 project, the cohorts of various DER technologies represented in the simulation model were expanded upon according to forecasts from AEMO's Integrated System Plan (ISP) [2]. The input assumptions workbook for the 2024 ISP was utilised in this project as this was the latest version available at the time it was produced. Where the previous study had simulated two different ISP scenarios however, in this study the average of two scenarios, namely the "Progressive Change" and "Step Change" scenarios, was used to develop PV and EV growth trajectories. The intention of using one set of growth trajectories formulated by averaging two of the ISP scenarios is to base the study on growth that is on the upper side of what is both possible and realistic. In other words, it was intended that the DER growth trajectories for this study should be close to, but on the upward side of what would be most likely to eventuate in practice. The forecasts indicated by the "Green Energy Exports" scenario in the 2024 ISP were not included in this study as the general expectation of the authors at the moment is that this scenario is the least likely to eventuate.

Outside of AEMO, the CSIRO and Green Energy Markets, the latter two of whom provided input data for the 2024 ISP, there are very few organisations that have estimated DER growth forecasts for the coming decades in Australia. One study that was carried out fairly independently, at least as far as the PV forecasting is concerned, was that which was performed by Blunomy Consulting for Energy Queensland so that they could prepare their Distribution Annual Planning Report for 2023 [4], [5]. The forecast period for this study was only until 2036. In the "Medium" scenario, which can be considered the most central of those modelled in [4], the cumulative power capacity of residential rooftop PV that is forecasted to exist in the state of Queensland by 2035 is approximately 67% higher than that which is implied by the average of the Progressive Change and Step Change scenarios from the 2024 ISP. Even in comparison to the 2024 ISP Step Change scenario alone, the forecast for 2035 is 10% higher. The average EV ownership per Queensland household by 2035 is also forecasted to be approximately 38% higher in the Medium scenario of the Blunomy study than it is in the average of the Progressive Change and the Step Change scenarios from the 2024 ISP. Growth in BTM BESS capacity forecasted for the same point in time is, on the other hand, approximately 34% lower in the former than in the latter.

The higher level of expected state-wide growth in PV capacity and EV ownership forecasted in [4] is largely attributable to higher estimates in the rate of population growth in Queensland. The authors used 1.5% – 1.6% per annum for their central scenario, which they sourced from the Deloitte Access Economics December 2022 Business Outlook [6]. On the other hand, the population growth rates for Queensland that are applicable to the Progressive Change and Step Change scenarios in the 2024 ISP are 1.2% per annum and 1.3% per annum respectively [7]. Additionally, the Medium scenario in [4] may lie closer to the centre of all possible energy sector growth trajectories than the average of the Progressive Change and Step Change scenarios from the 2024 ISP does, as the Green Energy Exports scenario is the one exhibiting the most rapid growth in the latter.

While it may be the case that separate arguments exist for both of these two sets of population growth assumptions being the most likely to eventuate in Queensland, the authors of the present study decided to use the DER growth forecasts indicated by the 2024 ISP, rather than those indicated by the Blunomy Consulting report. This decision was made for two reasons: (1) the ISP forecast period extends further out to include 2050 and (2) the ISP is informed more broadly by inputs from two separate organisations, as well as studies performed by AEMO itself, which should in principle improve its level of robustness. In any case; neither of these sets of DER growth forecasts can be proven to be the most likely to occur, but both of them fall within the upper and lower limits of what has been estimated to be possible extreme outcomes in either study and thus could be argued to be likely outcomes.

It is also noted here that the forecasts for PV capacity growth presented in [8], which was one of the inputs for the 2024 ISP, extend as far out as 2058. With these forecasts, the study period of this project, which was only carried out for 2025 – 2050, could have been extended further to include 2055. As the largest number of upgrades for which size optimisation had to be performed and costs had to be estimated occurred in the final five-year period of the study however, extending it out for an additional five-year period would have resulted in the inclusion of a large number of additional upgrades, which in turn would have increased the amount of effort required to complete the present project considerably. Furthermore, while having a wider study period may have improved the apparent predictive power of the study, the accuracy of cumulative upgrade cost estimates become increasingly questionable as they reach further and further into the future. It was therefore decided that the additional effort required to predict costs out to 2055 would not have been justified.

3.2 Modelled growth in rooftop PV installations and EV ownership

For the trend in rooftop PV growth that averaging of the Progressive Change and Step Change scenarios from the 2024 ISP produced for the state of Queensland, the starting point was approximately 3.49 kW of capacity per household on average; this is represented in Figure 1 by the blue curve. The average PV capacity per household for the modelled zone substation area identified as part of the baselining process in the previous project however was 2.13 kW. A trend which starts at this point but then grows at the same normalised rate as the ISP trend was produced; this is the orange curve visible in Figure 1. The PV growth trajectory that was utilised in this study was then produced by starting from the latter trend and gradually converging on the former by the year 2050, as shown by the grey curve in Figure 1.

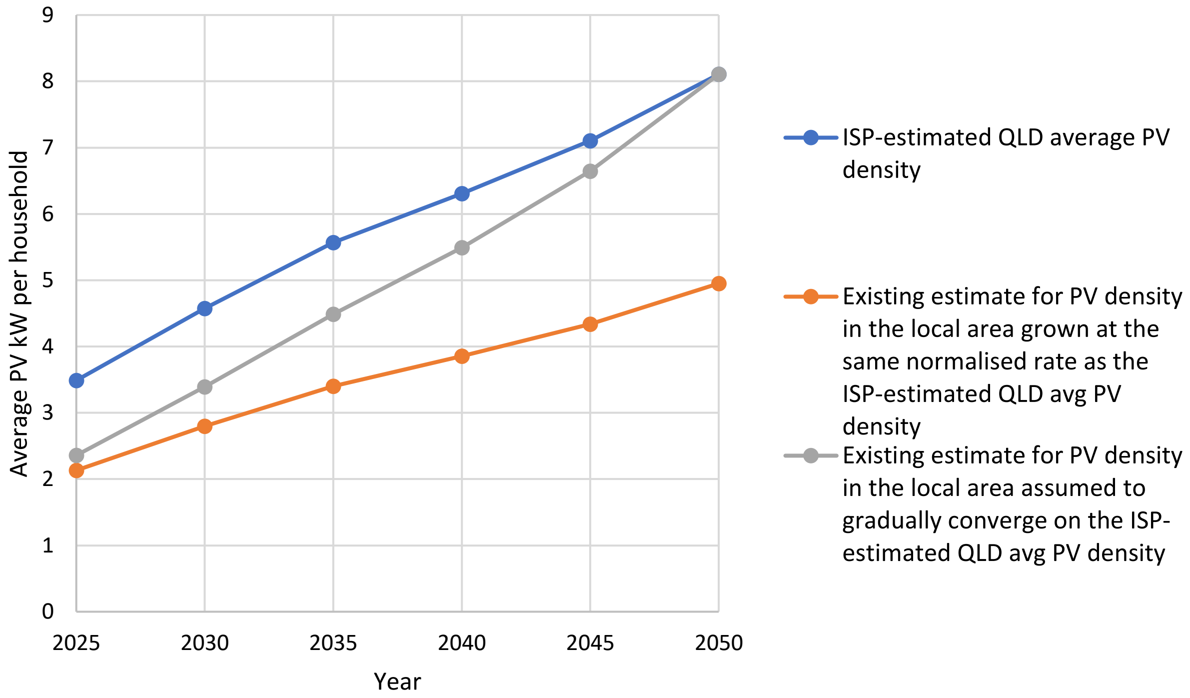

Figure 1 – ISP-estimated trend in rooftop PV power capacity growth per typical household in Queensland

During the baselining process in the first RACE for 2030 project which the present one proceeds from, no attempt was made to estimate existing EV ownership in the modelled zone substation area; it was assumed that existing EV ownership was zero. This assumption was also adopted in the present project; as a result, no interpolation between an existing cohort of vehicles and the expected emergent cohort needed to be implemented. It is likely that the level of present-day ownership would be negligible in any case, hence the amount of error incurred by approximating it as zero would be minimal.

The EV growth trend for Queensland implied by the average of the Progressive Change and Step Change scenarios from the 2024 ISP was utilised in the present project; this is shown in Figure 2.

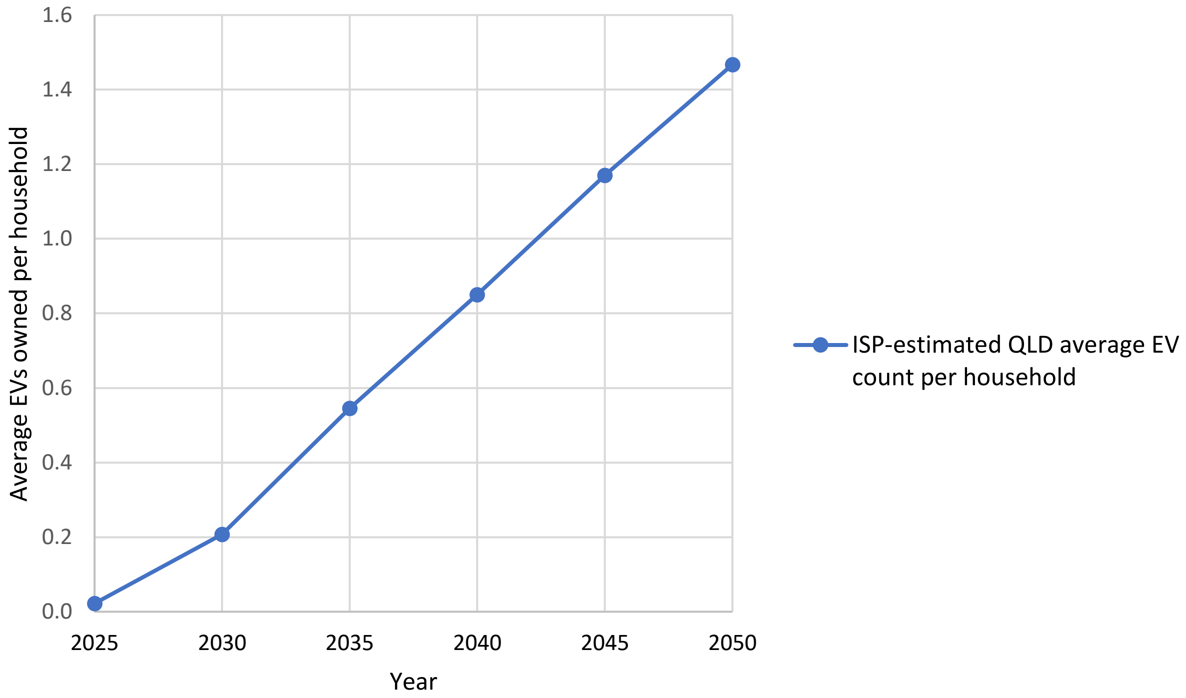

Figure 2 – ISP-estimated trend in EV growth per typical household in Queensland

3.3 EV charging assumptions

The same assumption around the sizes of EV chargers that would be utilised that had been adopted in the previous RACE for 2030 project was also adopted here. Two different sizes of EV charger were assumed: 3.68 kW and 7.36 kW. It was assumed that all customers with a single or double phase connection to the distribution network would own the smaller size of charger, while all customers with three phase connections would have the larger size of charger. While some residential customers in the modelled area may choose to have their connections upgraded to three phase connections in future, it is expected that the proportion of these would be small. The populations of customers owning EVs and each of the two sizes of chargers were represented throughout the course of each daily simulation using two separate after-diversity charging curves sourced from the section on unmanaged EV charging in [9]. These charging curves were formulated from a trial in the UK and are thus expected to constitute reasonable representations of EV usage in dense suburban areas in Australia as well. They correspond to weekday EV charging trends. While weekend curves were also available, these were excluded from the present study in the interests of simplicity and based on the fact that the weekday curves were identified as having sharper, higher peaks and are also representative of conditions that occur more often.

For the future scenarios modelled, new EVs were assigned to residential customers represented in the model at random using sampling from uniform distributions. This process was applied until the average EV ownership per household corresponded to the values shown at particular points on the EV growth curve in Figure 2 as appropriate. An upper limit of no more than two EVs per residential customer was enforced. While it is conceivable that some family households with a large number of occupants might own more EVs than this in future, it is more or less inconceivable that they would be likely to charge more than two EVs at any one time due to the large amount of secure garage space that this would require. The modelled area does represent power supply to a relatively small number of residential customers on large semi-rural properties at the fringe areas of the suburb. For the most part however, the residential customers represented by the model own properties in the size range that is typical of middle and low-income Australians and the upper limit of two EVs charging at any one property is considered appropriate. It is also noted here that charging of electrified trucks and other types of vehicles that would be used by commercial and industrial customers has not been represented in this study, as it is assumed that this will take place mostly at large depots located elsewhere from the area represented by the model.

Charging of EVs in this study was modelled using a Monte Carlo approach. The EV representations in each future state of the model were activated randomly using uniform distributions until the cumulative amounts of active power drawn by each of the 3.68 kW and 7.36 kW charger populations corresponded to the points on each of their respective after-diversity charging curves from [9] when averaged across each of those populations respectively. It was also assumed that the population of the modelled suburb would not change significantly in future. In practice there may be some new high-rise apartment complexes built in the modelled suburb in future, which would impact the number of EVs purchased to some extent as EV ownership would be challenging to accommodate in such complexes. The growth of such complexes in the modelled suburb would be likely to be slow and is difficult to predict in general however, hence an assumption of no apartment complexes appearing in the modelled suburb over the modelling horizon was adopted for this study.

Variation case 1a assumes that a partially effective TOU tariff is realised and effects future EV charging behaviour for Australian household owners. While it would be desirable for a TOU tariff to result in all EV owners choosing to spread their charging evenly throughout the day and thus remove the simultaneity of their charging during the evening peak, it is impractical to expect that this would necessarily be the universal outcome in any real-world implementation of a tariff. Some consumers will still choose to charge based on when is most convenient for them, rather than when is most economical, regardless of what incentives are put in place. The original convenience-based charging profile and the charging profile altered by the TOU tariff are both shown in Figure 3.

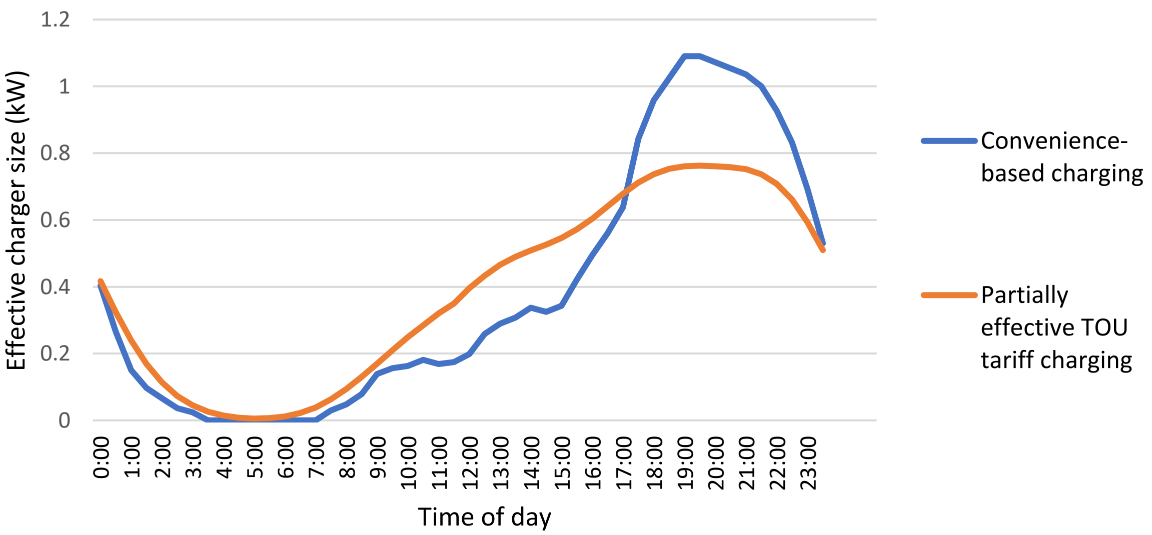

Figure 3 – Typical charging profile for EV with 3.68kW charger given purely convenience-based charging behaviour, as well as charging behaviour partially altered by a TOU tariff intended to incentivise charging throughout the middle of the day.

3.4 Modelled growth in behind the meter BESS

The potential effect of growth in behind-the-meter (BTM) BESS installations was also included in one variation case 1a of this study. For this case variation, the averages of the growth trajectories for BTM BESS power capacities and storage depths in the state of Queensland from the Progressive Change and Step Change scenarios in the 2024 ISP were calculated. Specifically, the figures on the ISP workbook tab entitled "Embedded energy storages" were used; it was assumed for the purposes of this project that this data is largely representative of growth in BTM BESS installations in households, rather than businesses. The state-wide growth figures extracted from the ISP workbook were then downscaled to "per household" estimates using the same population and housing growth assumptions that were employed in the previous project; refer to the report for that project for further details.

The resulting growth trajectories in BTM BESS power capacity and storage depth for the typical Queensland household are shown in Figure 4. Note that while typical household BTM BESS power capacity rises gradually, the storage depth of the typical installation actually recedes slowly as the years progress. While applying average power and energy ratings for BTM BESS growth results in BTM BESS power absorption ending earlier in the day than it would do for some homes for which units with larger storage depth have been produced, it is expected that the error incurred by such an approximation would be insignificant at a zone substation scale.

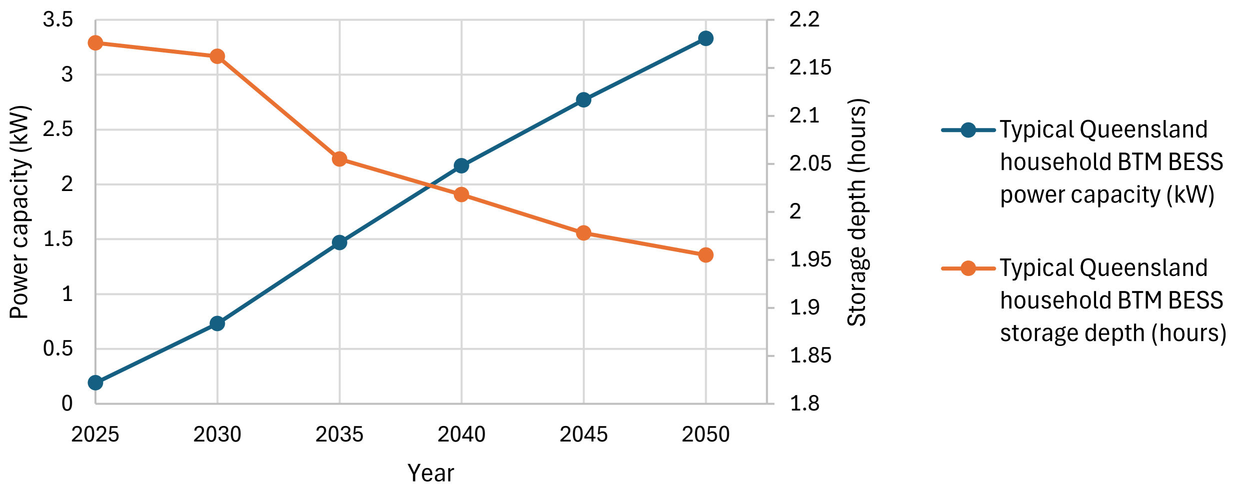

Figure 4 – Growth trajectories in BTM BESS power capacity and storage depth for the typical Queensland household

The BTM BESS installations modelled in variation case 1a were pessimistically assumed to be operated in a simplistic, sub-optimal fashion with respect to network security. Specifically, it was assumed that they would charge at the maximum rate possible throughout the morning period and thus typically run out of storage depth before midday. This pattern of charging aligns with conclusions made in a previous ARENA study for typical Victorian customers in a variety of different types of network areas [10].

If they were controlled in response to strong network tariffs incentivizing charging across the midday period, or (equivalently) in participation with virtual power plants (VPPs); BTM BESS installations could provide more network support by acting to alleviate thermal overloads across the majority of the midday period. Notably, the assumption that future BTM BESS installations would typically be controlled in this fashion was made in [4]. While this would be a beneficial outcome for DNSPs if it were to occur in a statistically robust and reliable manner, the authors of this study consider it likely that some subset of the growing population of BTM BESS owners will still choose to opt out of VPP schemes and/or largely ignore any tariffs created. The existence of this subset will be likely to mean that DNSPs cannot rely on BTM BESS installations to charge and discharge with timing that serves to optimise alleviation of thermal constraints on every day of the year. They will therefore need to size their solutions to LV and MV network thermal overloads as if these installations were used sub-optimally in general.

This line of reasoning also justifies the absence of TOU-tariff-based alterations to EV charging profiles and BTM BESS installations from case 1, which is the central case for this study. While it is clear that both BTM BESS installations and EVs are in the process of gradually emerging in the Australian electricity sector, they both constitute mechanisms of influence on distribution network voltages and currents that will lie outside of the direct control of the DNSPs in general. The creation of TOU tariffs for EVs is dependent on the outcome of both state and federal political decisions, which are inherently difficult to predict. The most optimal implementation of such a scheme from both technological and economic perspectives is also not widely agreed upon in the literature [9]. Furthermore, the 2024 ISP workbook data also does not assume that EV TOU tariffs will be realised. The growth in BTM BESS technology is also likely to be somewhat dependant on political decisions, such as the creation of incentives, as the price point for this technology lies outside of the financial capabilities of the typical homeowner at present even in developed countries like Australia and is likely to remain so long into the future [10]. While the ISP clearly anticipates some significant growth in BTM BESS installations, it is expected that this growth would not be uniform across all suburbs i.e. more of it will be likely to occur in the more affluent areas. The intention of this study is to represent network upgrade costs in the typical Brisbane/Australian suburb.

4 Existing system and limitations

4.1 Existing network description

The modelled area is a typical suburb in the city of Brisbane in Queensland. The voltage levels at which the distribution network for this area operate are 11 kV, which is referred to as the medium voltage (MV) level of the network, and 433 V, which is referred to as the low voltage (LV) level of the network. There is a total of 13,535 residential customer connections in this area as well as 785 commercial and light industrial connections. The commercial customer connections are largely represented by small businesses such as restaurants, fuel stations, aged care homes, schools and shopping centres. The light industrial customer connections are mostly made up of warehouse facilities, with the exception of one water treatment facility. Due to the lack of available transformer monitor data, the sizes of the loads representing the water treatment facility in the MV network model that was provided by Energy Queensland during the first RACE for 2030 project were left unchanged i.e. not altered by residential electric vehicle charging load growth represented in this study. Figure 5 provides a topological overview of the modelled network area.

Figure 5 – Topological overview of the modelled network area

The zone substation area modelled contains 259 distribution transformers feeding residential LV areas and commercial customers. The zone substation supplying the network in the modelled area consists of ten MV feeders which have been re-named as “Feeder 01” through to “Feeder 10” so as to de-identify the area. Several attributes which characterise these feeders are listed in Table 21 in Appendix A – Characteristics of the existing network. The different types of MV and LV overhead distribution lines and buried cables in the modelled area, as well as the cumulative installed lengths of each are further detailed in Table 22 through to Table 25 in Appendix A – Characteristics of the existing network. Note that the cumulative installed lengths indicate the relative prevalence of the different conductor types in the network.

4.2 Simulation and modelling details

Studies in this project were carried out using load flow simulations in the power system modelling package PowerFactory. The network model representing a zone substation area feeding 13,535 residential customers and 785 commercial and light industrial customers in a collection of suburbs in Brisbane, Australia that was produced during a previous RACE for 2030 project was utilised. This model has been publicly released and is available for research purposes at GitHub - edwardburstinghaus/RACE2030-1-package.

The network simulation model includes quasi-dynamic simulation language (QDSL) models that incorporate the effect of volt-watt and volt-var algorithms on recently installed PV generators into the load flow simulations. The Australian standard AS4777.2 mandates that volt-watt and volt-var algorithms should be implemented on existing and future PV inverters [11]. While some studies indicate that existing compliance with AS4777.2 is poor [12], it was assumed for the purposes of this study that universal adoption of it would be adhered to by solar PV inverter installers moving forward. It is also known to be the case that many Australian DNSPs apply 5 kW export limits on many solar PV systems; but for the purposes of this study, it was assumed that all future PV installations would not be subjected to export limits. This assumption was made because the central intention of this study was to explore the costs for protecting the network from thermal overloads if the solar PV installations purchased by Australian household and business owners were to be utilised as much as possible, rather than hindered by export limits or DOEs.

Python scripts were developed to automate load flow simulations with the model and alterations to the sizes of the load components were used to produce representations of electric vehicles (EVs). Buried LV cables and LV overhead lines (OHLs) were modelled using coupled four-wire representations in the PowerFactory program and loads and PV installations were also modelled in an unbalanced fashion. This meant that unbalanced voltages and currents resulting from the uneven distributions of load and solar generation on each phase would be accurately represented.

The volumes of solar generation and native load in the modelled area were set using a baselining process that utilised real-world transformer monitor and SCADA measurements provided by Energy Queensland. Half-hourly daily scaling curves for the load and rooftop PV components in the existing network model representing conditions that were found to be typical of measurements taken in the period 30/04/2021 - 30/10/2022 were produced using a detailed baselining process that was carried out as part of the previous RACE for 2030 project. Measurements incorporated into the baselining methodology included both substation SCADA recordings and transformer monitor datasets collected on a large proportion of the distribution transformers in the modelled area. Characteristic curves for both days with high solar irradiance and days with low solar irradiance in each of the four seasons across the year were developed. Refer to [3] for further details on the development and features of the PowerFactory network model used in this project, for how EVs and the volt-watt and volt-var algorithms on PV inverters were represented in it and for the methodology that was used to baseline the model.

For the modelled zone substation area, the midday trough in substation power flow is deeper in winter than it is in any other season. This is demonstrated by the baselined load profiles for the modelled zone substation area that are shown in Figure 6. Midday simulations were however based on spring high solar conditions rather than winter high solar conditions because, according to the rooftop PV utilisation factors predicted for Brisbane by the program Helioscope, the expected peak solar irradiance at noon is approximately 17% higher in spring than it is in winter. The peak PV utilisation factors which were predicted by Helioscope to be typical of rooftop PV installations in the modelled zone substation area are shown in Table 3.

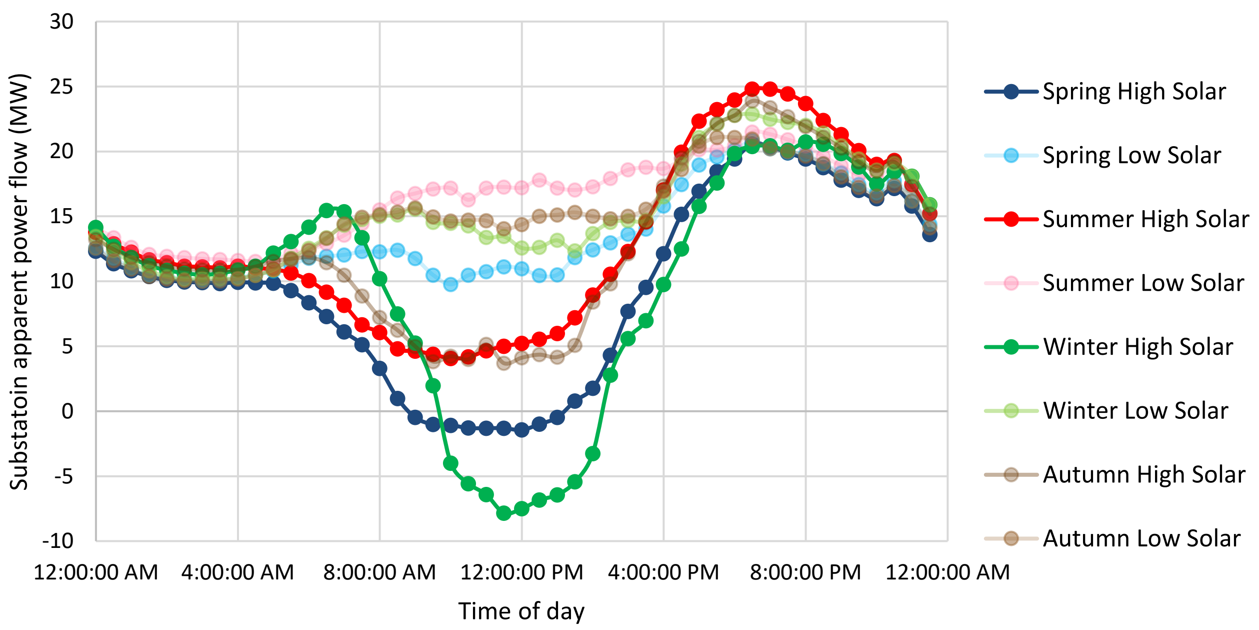

Figure 6 – Baselined substation active power flow for the modelled network area given different seasons and high and low solar irradiance throughout the day

Table 3 – Peak PV inverter utilisation factors (%)

Summer	Autumn	Winter	Spring
100	97.62956	82.89305	100

The deeper midday load trough for winter high solar conditions given the present-day state of the network is likely to be attributable to variations in the utilisation of household appliances across the seasons, especially air-conditioners. Specifically, residents are expected to be less likely to use their air-conditioning to warm the house in the middle of a mildly cold winters' day than they are to use air-conditioning to cool their house down in the middle of a hotter spring day. Because the peak PV utilisation factor is predicted to be higher in spring than it is in winter, it is also expected that the midday load trough for a typical spring high solar day will become deeper than the one for a winter high solar day as the penetration of rooftop PV increases over the coming years and decades.

Unlike the existing PV installations in the model, which were baselined to unique scaling factors dependant on real-world measurements, PV installations added to the model in the future years of the study were assumed to generate active power at 100% of rated inverter capacity in the middle of high solar days. The time resolution for the load flow simulations was each half hour of the typical high solar spring day.

Load flow simulations performed for the purpose of measuring thermal constraint violations on LV networks were repeated five times each, with the same cumulative proportions of EVs charging but with a different random assignment of which particular customers would be charging their EV enforced for each simulation. In the interest of conservative solution sizing for LV constraints, the maxima of the thermal loading factors for distribution transformers, buried LV cables and LV OHLs produced by the five simulations performed for each particular condition were used to determine the extent of LV thermal violations that would need to be rectified. The averages of the thermal loading levels measured on buried LV cables or LV OHLs were used to determine thermal relief that would be realised by LV area splitting upgrades; a type of traditional network upgrade that will be explained later in this report. In the case of thermal violations on the MV network, these were identified to exhibit insignificant variation with random assignments of the same cumulative volume of EV charging load. Therefore, only one load flow simulation was used for measuring thermal constraint violations on the MV network in general.

The representations of underlying present-day load and generation profiles in this study were limited to what was typical during high solar conditions in spring in 2021 and 2022 because the resources available during this study were also limited. It is noted here that typical planning studies carried out by DNSPs employ much more detailed forecasts of load, PV generation and other DER technologies. These forecasts are generally thorough enough to include statistical distributions of expected load and generation levels across each day of a given year. While such detailed estimates are necessary to justify proposals for investments in network upgrades, they are not necessary for indicative research purposes as is the objective of the studies conducted for this report.

4.3 Expected BAU growth in thermal and voltage violations

The first set of simulations that were carried out for this project were used to perform an assessment of the growth in thermal and voltage violations that would occur across the network model given the forecasted PV and EV growth trajectories discussed in the previous section of this report if no rectification measures for these types of issues are applied i.e. in a BAU scenario.

Conductors at the LV level of the network were only considered to be thermally overloaded when their loading factors exceeded 120% in the middle of the day under high solar conditions. This is appropriate for LV OHL spans because upgrades to these will often be avoided for as long as possible in practice; surveys of lines suspected to be reaching or exceeding their nominal current ratings will generally be conducted and the minimum sag heights of such lines in the middle of the day recorded, so that acceptability of temporary exceedances of the nominal ratings can be established if possible. For LV buried cables, the selection policy commonly used by DNSPs in their networks allows a substantial margin; sufficient that the variability in thermal conductivity of the different soil types can be accounted for without additional design effort, and this also allows for cyclic ratings to be considered. Although no actual cyclic rating calculations were undertaken in this study, the experience of senior practitioners indicated that a short-term overload of up to 120% of the continuous rating, for a few hours, would not be likely to cause significant loss of life in buried cable systems.

Distribution transformers in the modelled zone substation area were only considered overloaded when they were found to be loaded at 150% or more of their thermal capacities. The additional 50% in thermal margin was used because typical distribution transformers used by Australian DNSPs are generally able to withstand currents higher than their rating for short periods of time; this is referred to as their "cyclic loading" capabilities. It is expected that in practice it would be unlikely that the cost to replace these devices would be committed to until their peak loading factors were found to have become as large as 150%. A lower threshold of 90% is used to declare thermal overload of MV conductors; justification for this lower threshold is explained later in section 5.

The results for the BAU simulations at noon in spring under high solar conditions in case 1 are shown in **Table 4**. A table with the same information as **Table 4** for BAU in variation case 1a is shown in Appendix C. A variety of metrics were measured to assess the state of the network if no remediation measures for the growth in rooftop PV are enacted by the DNSP, such as percentages of transformers, buried cables and OHL spans at the MV and LV levels of the network that breach specific loading factors. The prospective rooftop solar power injection, amount of curtailment and the percentages of LV areas exhibiting overvoltages and thermal violations are also shown. The LV areas were recorded as being in a state of overvoltage if one or more of their buses were found to exhibit line to neutral voltages exceeding 253 V on one or more of their three phases. A state of thermal overload was declared in a given LV area at least one of the four conductors of a given LV buried cable run or OHL span in its network exceeded 120% of its rating or the loading on its transformer was found to be exceeding 150% of its rating.

Table 4 – Results for BAU simulations at noon in spring under high solar conditions in case 1

Year	2025	2030	2035	2040	2045	2050
Percentage of LV areas with overvoltage on at least one phase of one LV bus (%)	3.5	5.7	8.7	17.9	21.5	30.3
Percentage of LV areas with thermal overloads on at least one conductor span/run or the transformer (%)	0.0	0.0	2.2	7.0	19.7	34.5
Percentage of LV buses in overvoltage on at least one phase (%)	0.7	1.4	2.3	3.8	5.5	8.0
Proportion of transformers loaded over 100% (%)	0.0	3.3	15.3	27.1	39.3	54.7
Proportion of transformers loaded over 150% (%)	0.0	0.0	1.3	6.6	16.9	27.5
Percentage of the cumulative length of MV OHL spans loaded over 90% (%)	0.0	0.0	0.0	0.0	0.2	1.5
Percentage of the cumulative length of MV buried cable runs loaded over 90% (%)	0.0	0.0	0.5	6.9	9.8	19.7
Percentage of the cumulative length of LV OHL spans loaded over 100% (%)	0.0	0.0	0.2	0.4	1.6	3.6
Percentage of the cumulative length of LV OHL spans loaded over 120% (%)	0.0	0.0	0.1	0.2	0.7	1.6
Percentage of the cumulative length of LV buried cable runs loaded over 100% (%)	0.1	0.2	0.2	1.1	3.3	7.2
Percentage of the cumulative length of LV buried cable runs loaded over 120% (%)	0.0	0.0	0.0	0.2	1.2	3.4
Curtailment (%)	0.8	0.9	1.1	1.5	1.8	2.2
Intended solar power injection (MW)	11.4	21.8	32.5	42.1	53.1	66.7

Note that the overvoltage metrics shown in the first and third rows of **Table 4** use different denominators. The metric in the first row reports the overvoltages as a percentage of all LV areas exhibiting overvoltage on at least one phase of at least one bus in that LV area. The metric in the third row reports the overvoltages as a percentage of all LV buses exhibiting overvoltage on at least one of the phases for that individual LV bus. In other words, the first metric produces a less granular view of overvoltages as it only requires overvoltage on one bus in the large set of buses for each LV area before overvoltage is declared for the entirety of that LV area.

The growth in the number of LV areas exhibiting thermal overload and overvoltages both indicate that severe operational issues will emerge in the modelled zone substation area in the future if no augmentations are made to rectify these problems. Overvoltage issues emerge earlier than thermal overloads do, but nevertheless the latter has overtaken the former by 2050. Many of the thermal overloads occur at the level of the transformer. This is evidenced by the fact that the percentage of the 229 distribution transformers in the modelled zone substation that experience loading factors equal to or greater than 100% and 150% of their capacities both grow rapidly throughout the years from 2025 to 2050.

Overloads in the MV network under BAU develop much more significantly for buried cable runs than they do for OHL spans for two reasons. Firstly, all of the ten MV feeders in the modelled zone substation area are brought into the zone substation itself using buried cable. The load on each of the MV feeders is always accumulated most heavily at the sections that are electrically closest to the substation. Secondly, the ratings of OHL are generally higher than buried cable. The MV OHL conductor type with the highest rating, which is Moon strung in such a way that it can operate at up to 100°C, is rated at 582 A, while the MV buried cable type with the highest rating, which is 400mm^2 aluminium triplex, is rated at only 419 A. at the MV level of the network is largest grade of OHL are significantly larger than the current ratings of the highest grades of MV buried cable.

The situation is similar across the conductors of the LV network in as well; thermal overloads on buried cables emerge more rapidly than do overloads on OHL spans. The percentages of the lengths of the LV network exhibiting overload are somewhat lower than in the MV network, largely because less power is aggregated in the former than in the latter. For the LV conductors also, the greater prevalence of overloads on buried cables is again expected to be a consequence of the larger current ratings of LV OHL conductors when compared to the LV buried cable types.

Although the loss of potential renewably generated power is undesirable, the relatively low percentages of curtailed power at peak solar irradiance indicate that solar PV curtailment will not be a major issue for the majority of customers. More significant is the sheer size of the active power export from the zone substation that is created throughout the middle of the day due to excessive solar generation. In case 1 in 2050 given spring high solar conditions at midday, this increases to as much as 54.3 MW; in other words, the cumulative effect of native load, network active power losses and solar curtailment only reduces the 66.7 MW of prospective solar generation by 12.4 MW. In light of this fact, it is clear that the excess generation produced by the growing fleet of rooftop solar inverters will become a significant burden for the network to bear. Nevertheless, the implied costs for bearing this burden in the distribution networks would be likely to be less significant than if the equivalent renewable generation were realised in the form of transmission-scale solar and wind farms. The latter type of facilities necessitate buildout of expensive additional transmission infrastructure and also create larger active power losses due to their longer electrical distance from the load centres.

4.4 Zone substation overload determination

One of the major determinants of cost in each of the solution pathways investigated was the cost of upgrading the zone substation feeding the modelled area, or conversely of avoiding its upgrade.

In the traditional network solutions pathway, no augmentations to prevent the zone substation from becoming overloaded due to noontime solar-generated reverse active power flow were applied. In the MV BESS solution pathway, the same traditional network solutions applied in the traditional network solutions pathway were also utilised to address LV constraints, but MV BESS installations were added to each of the ten MV feeders in the modelled zone substation area in each year as needed to absorb enough of the excess solar-generated active power that the zone substation upgrade could be avoided.

In the LV BESS solution pathway, the power absorption realised by the LV BESS installations was also utilised to reduce the cumulative noontime solar-generated reverse active power flow through the zone substation to a degree that would prevent it from becoming overloaded. In the first instance, LV BESS installations were added to all of the LV areas with thermally overloaded transformers to address their corresponding thermal violations. In the years in which the volume of BESS capacity used to address LV constraints proved to be insufficient to prevent zone substation overload, additional LV BESS installations were applied across the network until it could be avoided.

The limit at which the zone substation would become overloaded was identified using the relevant security standard, which is described in the Distribution Annual Planning Report [15]. In the security standard, the point at which a quantity referred to as load at risk (LAR) reaches values higher than zero is used to determine when a given substation would become overloaded. Two types of LAR are considered: normal load at risk (LARn) and contingency load at risk (LARc). Accordingly, LARn is generally calculated using the difference between the 10% probability of exceedance (PoE) value in the annual load forecast for the substation and the normal cyclic capacity (NCC) of the thermally limiting equipment at the substation i.e. the power transformers. The LARc value on the other hand is calculated by adding together the transfer capacities and the short-term supply options that would be available during an N-1 contingency event i.e. an outage involving temporary loss of service of one major piece of power system equipment. This sum is then subtracted from the 50% PoE value in the load forecast.

In order that the identity of the particular zone substation modelled in this project would remain anonymous, the power ratings of the three power transformers at this substation were assumed to be different from their real-world values; it was assumed that the substation contains three 15 MVA power transformers. For the same reasoning, the available manual transfer capacity, that is the extent to which power can be manually shifted from 11kV feeders on the modelled zone substation to feeders that are parts of neighbouring substations areas, was approximated as 6 MVA for this substation. Note that both of these alterations are small enough that the hypothetical zone substation that has been effectively modelled still falls well within the vicinity of what is typical for the DNSP in question.

The calculation of LARc usually incorporates available emergency mobile generation services that can be used to restore service more rapidly during a contingency. The focus of the present study however is on overloads caused by excessive solar PV generation rather than load growth; mobile generation would not be able to alleviate excessive active power flow in the reverse direction leading back up into the sub-transmission network. The mobile generation that is available for the modelled zone substation was therefore disregarded in the estimation of the timing with which it would become overloaded due to solar-generated reverse power flow.

The substation power flow limit implied by the LARn for the modelled zone substation was found to be higher than the corresponding limit found to be implied by the LARc, thus the latter was used as the critical constraint. The LARc for a substation is normally calculated using the following equation:

$$LARc = 50PoE - available\ capacity - available\ supply$$

In the typical planning context that the above equation is applied, only power flows due to load exist and there is no reverse power flow due to excess solar generation. The 50PoE term normally refers to the 50% probability of exceedance load value from the annual load forecast. Depending on the time frame of the event being studied, the "available capacity" term refers to either emergency cyclic capacity, which is applicable for timeframes longer than two hours, or the two-hour emergency capacity, which is applicable for periods of two hours or less. Whichever of these is to be used, the available capacity term is equivalent to the minimum combination of these capacities that is produced by all scenarios involving one of the transformers in the substation being out of service. The "available supply" term refers to the sum of automatic, remote and manual load transfer capabilities that are applicable to the area under study, as well as mobile generation and mobile substation capabilities that could be deployed in some cases. Note that some of these terms can only be practically realised within certain delays and can also only be relied upon for periods less than certain maximal timeframes.

In the context that is relevant for this project, the critical scenario is caused by reverse power flow due to excess solar generation throughout the midday period. In this context, it is more meaningful to assume that the 50PoE term refers to the apparent power flow occurring at the zone substation when reverse active power flow at noon is maximised on a typical spring high solar day. As previously discussed, it is more appropriate to use spring than any other season for midday reverse active power flow simulation because future PV installations can be expected to generate at capacity at this time of day more reliably than in winter and the load at midday is also likely to be lower in spring than in summer as home owners will not turn on their air-conditioners during the day as often in the former as they will in the latter. Let the apparent power flow corresponding to maximal reverse active power flow through the substation at noon under high solar conditions in spring be denoted by S_{max}. Note also that it is important in this context to use apparent power, rather than just active power, as the much greater prevalence of volt-var injection from future PV inverters will cause the additional thermal loading applied to the equipment at the zone substation by reactive power flow to become non-negligible. While DNSPs do not utilise a measure like the one described here in place the 50PoE term at present, it is assumed for the purposes of this project that they would do something like this in the future.

The available capacity for a worst-case N-1 contingency at the substation studied for this project was calculated by supposing that one of the three power transformers at the substation had been taken out of service. In the context of reverse power flow due to excess solar generation, it is also clear that this problem will last for periods longer than two hours in the middle of the day in general. The emergency cyclic ratings, rather than the two-hour emergency ratings, were therefore utilised in the calculation of the available supply capacity term. A factor of 1.2 was applied to the sum of the normal cyclic capacity ratings of the remaining transformers to calculate their cumulative emergency cyclic capacity ratings. Noting that mobile generation services refer to diesel generator sets which cannot absorb active power, they would be irrelevant when attempting to alleviate excessive reverse active power flow. The only form of available supply in the reverse power flow context would therefore be the manual transfer capacity of 6 MVA that is available for the particular substation studied in this project. It is noted that this transfer capacity would not necessarily be useful if the adjacent area from which it was sourced also exhibited its own midday reverse power flow problems due to excess solar generation. For the purposes of this study, the simplifying assumption was made that manual transfer capacity without reverse power flow would be available.

The LARc for the modelled zone substation was therefore calculated in each year simulated as:

$$LARc = S_{max} - (3 - 1) \times 15 \times 1.2 - 6$$
$$= S_{max} - 42$$

A plot of the LARc for the modelled zone substation area in BAU is shown in Figure 7. Upgrade of the substation is required when the LARc becomes greater than zero. This occurs between 2040 and 2045 in both case 1 and case 1a. While the additional EV charging load provides some relief for the substation in case 1a, this relief does not significantly alter the timing with which the substation LARc value becomes unacceptable.

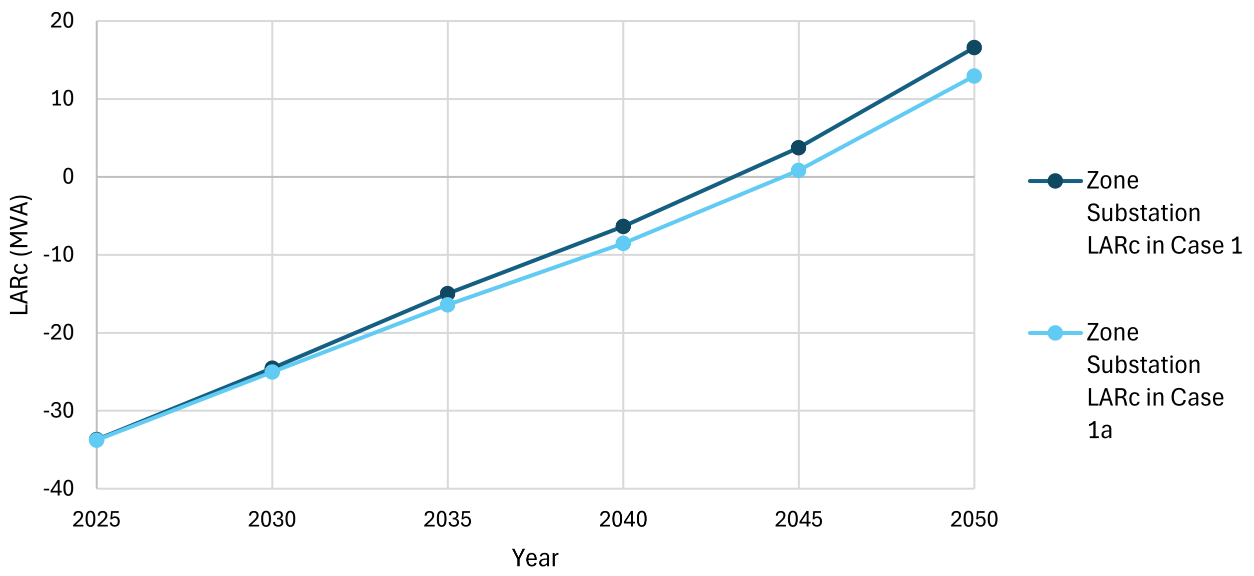

Figure 7 – Substation BAU LARc in case 1 and case 1a

4.5 Future growth in the substation load profile

The variation in the daily active and reactive power flow curves for the zone substation in BAU across the six time periods captured by the study are shown in Figure 8 and Figure 11 respectively. The reverse active power flow through the substation during the midday period reaches a peak magnitude of approximately 54.8 MW by 2050. The evening peak active power flow due to EV charging also increases to approximately 42.7 MW. It is clear that the deepening of the midday load trough due to PV growth occurs more rapidly in the years following 2025 than does the gradually rising evening load peak. Due to the absorption of reactive power by PV inverter volt-var algorithms throughout the midday period, the reactive power flow through the zone substation also increases to the considerable value of approximately 20.7 MVAR by 2050 in BAU.

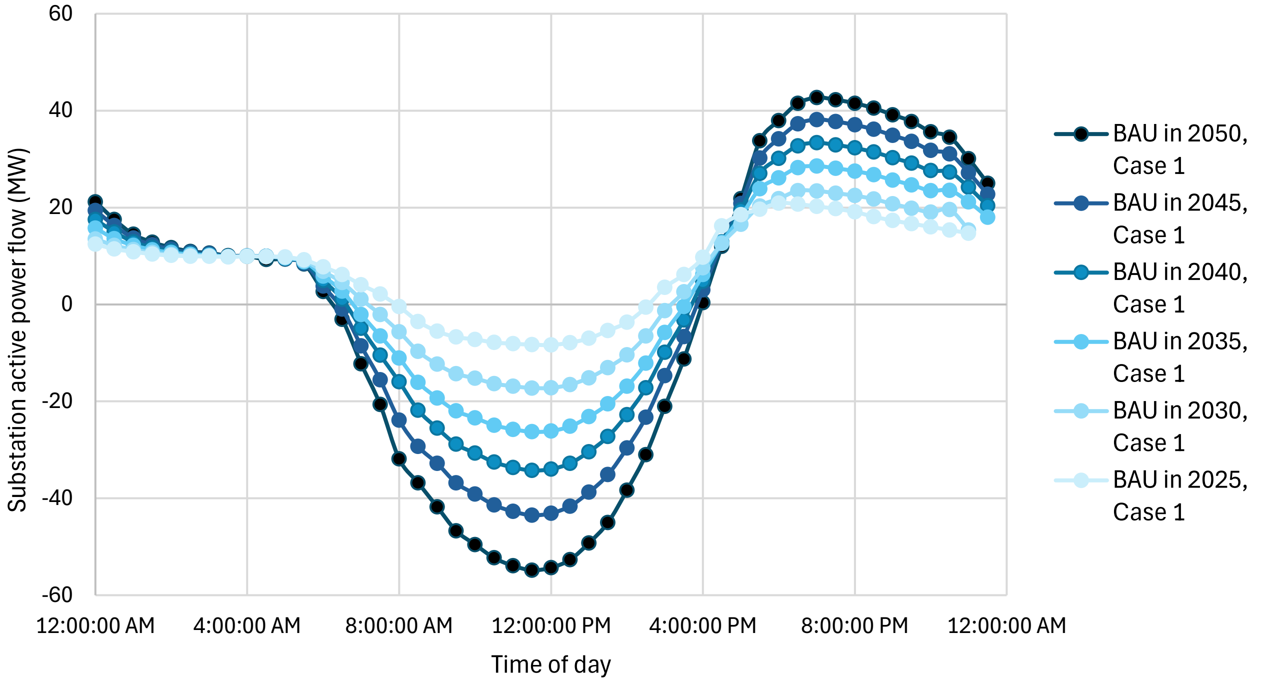

Figure 8 – Variations in substation daily active power flow in BAU in case 1 across the study period

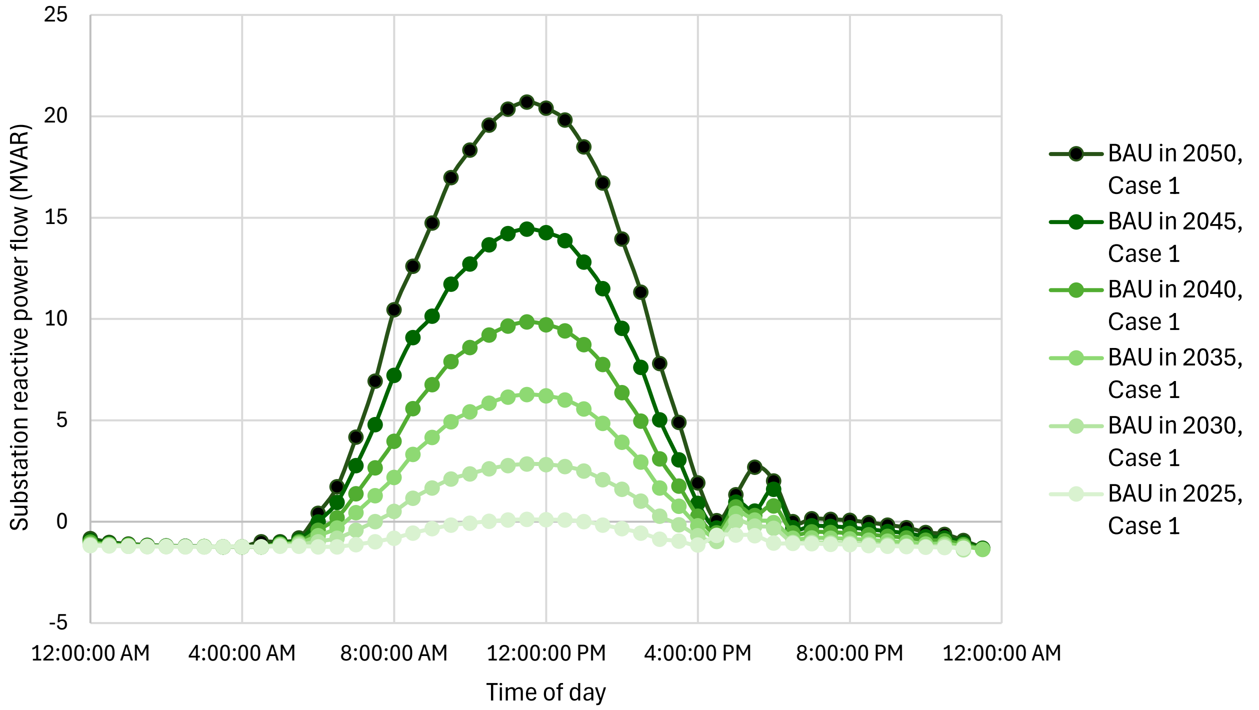

Figure 9 – Variations in substation daily reactive power flow in BAU in case 1 across the study period

5 Solution pathways

5.1 LV network solution application criteria

As regulated monopolies, Australian DNSPs are not able to apply solutions that would rectify all of the problems they can forecast as emerging in their networks as early as they would like. To be granted the funding that they need to finance upgrades, these organisations must justify and explain the need for them to the regulator at least five years ahead of time. As the extent of their material, financial and human resources are limited, they must carefully plan and prioritise which upgrades to their network are the most pressing and necessary in the short, medium and long-term. They therefore tend to devise very specific criteria that must be met before any solution will be applied.

In accordance with this, specific criteria which broadly reflect the way in which DNSP planning departments operate have been utilised in all three of the solution pathways investigated in this project. While the criteria and methodologies used by DNSP planning engineers would be more detailed and thorough than what has been applied here, the approximations of their nature and the intent behind them are expected to be adequate for research purposes. It is also important to note that the frequent and wide-scale thermal overloads of equipment across Australian distribution networks due to solar-generated reverse power flow in the middle of the day that are expected to emerge in the coming decades have, for the most part, not commenced yet. Approximations of the methodologies that would be used by the DNSPs to address these are therefore necessarily somewhat speculative.

For the reasons explained in the previous section of this report, LV underground and overhead conductors were only declared thermally overloaded and in need of an upgrade when their loading factors were found to have increased beyond 120%. Furthermore, thermal overloads of buried cables and OHLs in each of the modelled LV areas were not assumed to be rectified at the time that they would first occur. Rather, it was assumed that they would be addressed when the particular distribution transformer connecting them to the 11 kV network first becomes overloaded. The justification for this is twofold. Firstly, most of the DNSPs in Australia have limited or no visibility of the thermal loading of their LV networks themselves at present. Monitoring devices measuring the loading patterns on distribution transformers are in many instances the most downstream point of visibility that network operators have. Thermal overloads on LV buried cables and OHLs would therefore be unlikely to be picked up until the distribution transformer that feeds them becomes overloaded. Secondly, since DNSPs have limited field personnel and time to work with, they must upgrade their networks as efficiently as possible. This implies that their upgrade projects would be likely to include measures to remediate all issues present and emerging in a given LV area being addressed. In accordance with this, it was assumed that overloads of LV buried cable runs or OHL spans in a given LV area having an overloaded transformer addressed would also be rectified if the ten-year extrapolations of their loading factors were projected to exceed 120%.

5.2 Methods for selecting and sizing solutions to LV network thermal issues

While the DNSP's criteria on when to trigger LV area upgrades has been assumed to reflect the intention to delay such investments for as long as it is practically safe to do so, the criteria that they would use to size these upgrades would be likely to err in the opposite direction. In other words; they would be likely to size the upgrades with the intention of ensuring that re-emergence of the overload/s would be prevented for as long as possible, so that the financial inefficiency that would be implied by needing to return to the same LV area to implement upgrades after only a few short years would be avoided in general. Assuming that this would be the case, upgrades were sized with the specific objective of limiting the loading factor on the distribution transformer, buried LV cable run or LV OHL span that would be expected to occur in ten years' time to 100%. Estimation of the expected ten-year loading factors were based on linear extrapolation of the load growth for that piece of equipment which would have been observed over the previous five-year period. While the DNSPs generally have their own internal forecasts of average network-wide growth in PV, EVs, other DER and underlying load that they would refer to, it has been assumed in this project that in the case of specific LV area upgrades they would rely predominantly on the recently observed local growth of constraints when planning network upgrades.

In all three of the solution pathways, thermal overloads on distribution transformers were rectified using transformer size upgrades if this was found to be adequate as this was universally the cheapest option. Power ratings for pole-mounted transformers were limited to 25 kVA, 50 kVA, 63 kVA, 100 kVA, 200 kVA and 315 kVA. Power ratings for pad-mounted transformers feeding underground LV areas on the other hand were limited to sizes of 500 kVA, 750 kVA, 1000 kVA and 1500 kVA. Thus, when the extrapolated ten-year loading factor on the transformer exceeded 315 kVA for a pole-mounted unit or 1500 kVA for a pad-mounted unit, an alternative remediation strategy dependant on the solution upgrade pathway was applied.

For all LV areas that were identified as having critical transformer overloads in the time period being assessed, the potential for emerging thermal overloads on the LV buried cables and LV OHLs were also assessed. As described in the previous subsection, rectification of the latter was assumed to be triggered if linear extrapolation implied that they would emerge within the next ten years from the current time period. Re-conductoring was only assumed to be a valid rectification measure for LV buried cable runs with emerging overloads if their existing rating fell below that of 240mm^2 aluminium, because this was assumed to be the largest LV buried cable size that could be installed in any LV area in general. Similarly, re-conductoring was only assumed to be a valid rectification measured for LV OHL spans with emerging overloads if their existing rating fell below the assumed maximum upgradable rating of LV Moon. Even when the existing LV cable run or OHL span was at a rating lower than the maximum one achievable, the size of the rating bolster that would be realised by upgrading to these maximal sizes was often found to be insufficient to address the constraint. Re-conductoring at the LV level of the network was therefore not used as a rectification measure in case 1 in general.

The type of remediation measure applied to address thermal constraints in the traditional network upgrades solution pathway when a transformer size upgrade alone had been found to be insufficient was LV area splitting. This type of upgrade involves creating new open points along the LV feeder as needed to isolate some or all of the existing feeder from the original LV area and distribution transformer that it is connected to. A new distribution transformer is then installed somewhere along the length of the new isolated section of LV feeder to connect it to the MV network, or, where possible, a connection to another existing distribution transformer that is located nearby is used. Take the system shown in Figure 10 is taken as an example. There is an overload on transformer A that can't be addressed with a size upgrade and there are no overloads on any of the spans/runs of the LV feeder to its right.

Figure 10 – Existing LV area in which transformer A is overloaded

If this is the case, it may be possible to realise the necessary thermal relief by rearranging the open points to what is shown in Figure 11 and in so doing, make use of any spare capacity in transformer B. For this to be adequate, this requires that the ten-year extrapolated maximum power flow on the existing LV feeder at new open point A is sufficient to provide the thermal relief that is needed for transformer A. It is also necessary that transformer B has sufficient ten-year extrapolated thermal capacity to bear the additional solar-generated reverse power flow that was previously moving towards the left at new open point A.

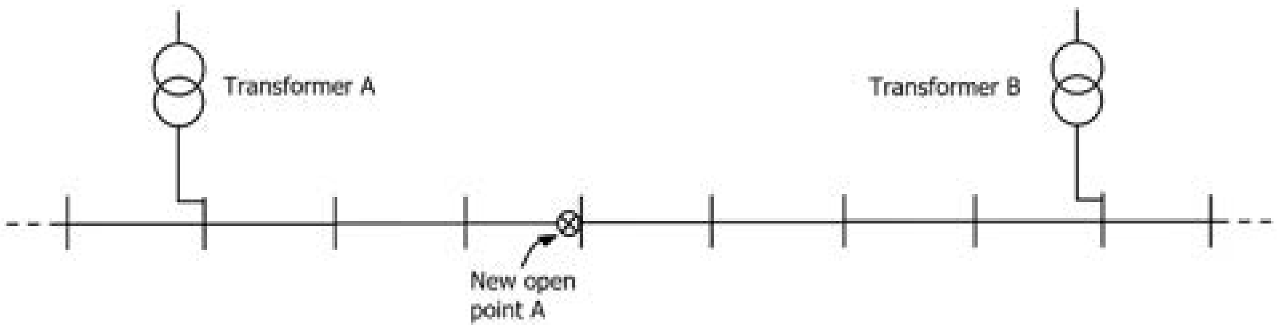

Figure 11 – LV area splitting upgrade utilising transformer B

If it happens that the remote end of the existing LV feeder does not end on an open point that could tie into the network of another existing transformer with spare capacity, then a new distribution transformer must be installed somewhere beyond new open point A.

Suppose on the other hand that the situation of the existing LV feeder aligns with what is shown in Figure 12. Not only is transformer A overloaded, but the first four spans of the feeder to the right of it are also projected to overload within ten years. Adequate relief for the overloaded spans/runs cannot be provided by placing the new open point at the same location as in Figure 11; the new open point must instead be placed an additional span/run to the right of this. Furthermore, since no existing transformer with spare capacity exists on the other side of any open point at the remote end of the feeder, a new transformer must be installed beyond the new open point as depicted in Figure 13.

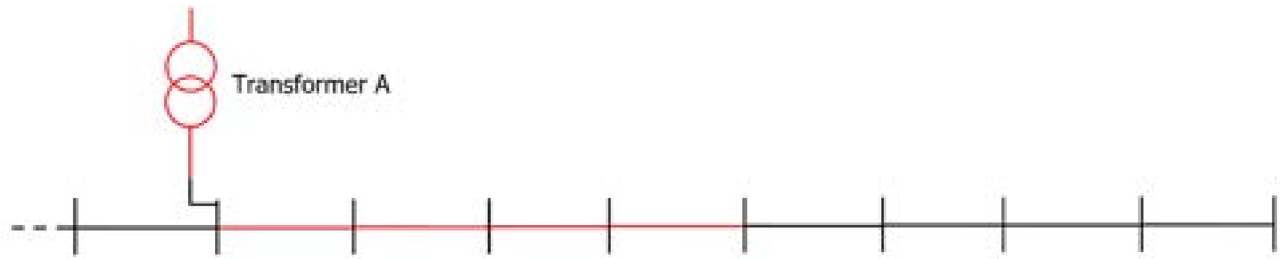

Figure 12 – Existing LV area in which transformer A and four spans/runs of one of its existing LV feeders are overloaded

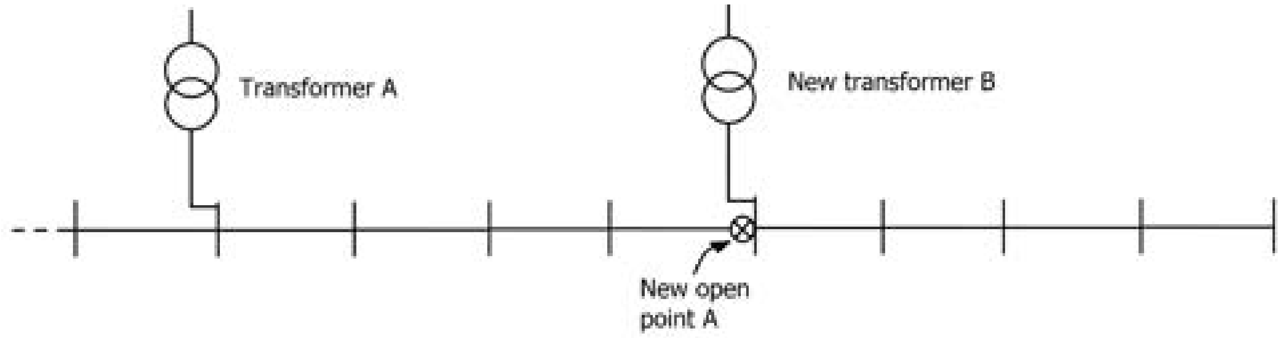

Figure 13 – LV area splitting upgrade requiring installation of a new transformer downstream of where the most remote overloaded span/run was located

Sections of the low voltage distribution network are often constructed in such a way as to share the infrastructure that is used by the 11 kV network i.e. LV OHL spans are strung on 11 kV poles directly below 11 kV conductor spans or LV cables are buried in the same trenches as the 11 kV cables. In this report, this will be referred to simply as *LV lines that are co-located with the MV*. The bus in the LV network at which the new distribution transformer in an LV area splitting upgrade must be placed may or may not fall within cable runs or OHL spans that are co-located with the MV network. If it falls within co-located runs or spans, this is advantageous for the cost of the upgrade because it means that a connection to the MV network can be established without needing to build out any new 11 kV network. If it falls within spans or runs that are not co-located with the MV network, then the cost for additional 11 kV buildout must be included in the cost for the LV area splitting upgrade. It is for this reason that the new transformer in an LV area splitting upgrade would typically be placed at the first bus downstream of the new open point as shown in Figure 13. In cases where the existing LV network is not co-located with the MV network, placing the new transformer further away from the existing one towards the remote end of the original LV feeder would usually imply placing it further away from the existing MV network also; this would therefore increase the cost of the MV buildout that would be needed.

For the LV BESS upgrades pathway, LV BESS installations were applied as the LV thermal overload rectification measure wherever possible. It was assumed that BESS installations would only be available with power capacities of 20 kW, 31.5 kW, 50 kW, 63 kW and 100 kW; these capacities correspond to typically available inverter ratings. It was also assumed that the BESS installations could be procured with any integer number of hours' worth of energy storage capacity. No more than 100kW of BESS capacity was permitted per LV feeder in cases 1, 2, 3 and 4 as well as in variation case 1a. Note that an LV feeder was defined to be one radial branch leading away from the LV terminal of the distribution transformer. Where thermal overloads were found to persist following application of the maximum permitted size of BESS capacity on a given LV feeder; re-conductoring, transformer size upgrades and LV area splitting upgrades were applied to resolve these.

In variation case 1b, the restriction on maximum BESS capacity per LV feeder was lifted. The distribution of larger BESS connections that this resulted in is detailed in section 7 of this report. Only LV area splitting upgrades which had involved the more expensive augmentation type of buried LV cable buildouts in cases 1 and 1a were displaced with LV BESS installations in case 1b however. The reason for this is that the displaced traditional network augmentation cost was found to be a similar size to the additional BESS installation cost, or sometimes larger, for only this particular type of LV area upgrade. It is expected that attempting to use LV BESS capacity to displace any of the other cheaper types of traditional network upgrade solutions for LV constraints would only have inflated the overall cost for the LV BESS solution pathway in case 1b. Note also that the overall cost benefit of displacing LV area splitting upgrades involving buried cable buildout with additional LV BESS capacity in case 1b was expected to arise because of the fact that the additional BESS installations also have a secondary benefit of providing part of the cumulative network-wide BESS capacity that is needed to prevent MV network overloads and the eventual upgrade of the zone substation from occurring.

The sequences of decisions corresponding to the process for selecting and sizing solutions to thermal overload issues on LV networks and their distribution transformers that has been described for the LV BESS solution pathway and which was employed in cases 1, 1a and 2 is detailed in

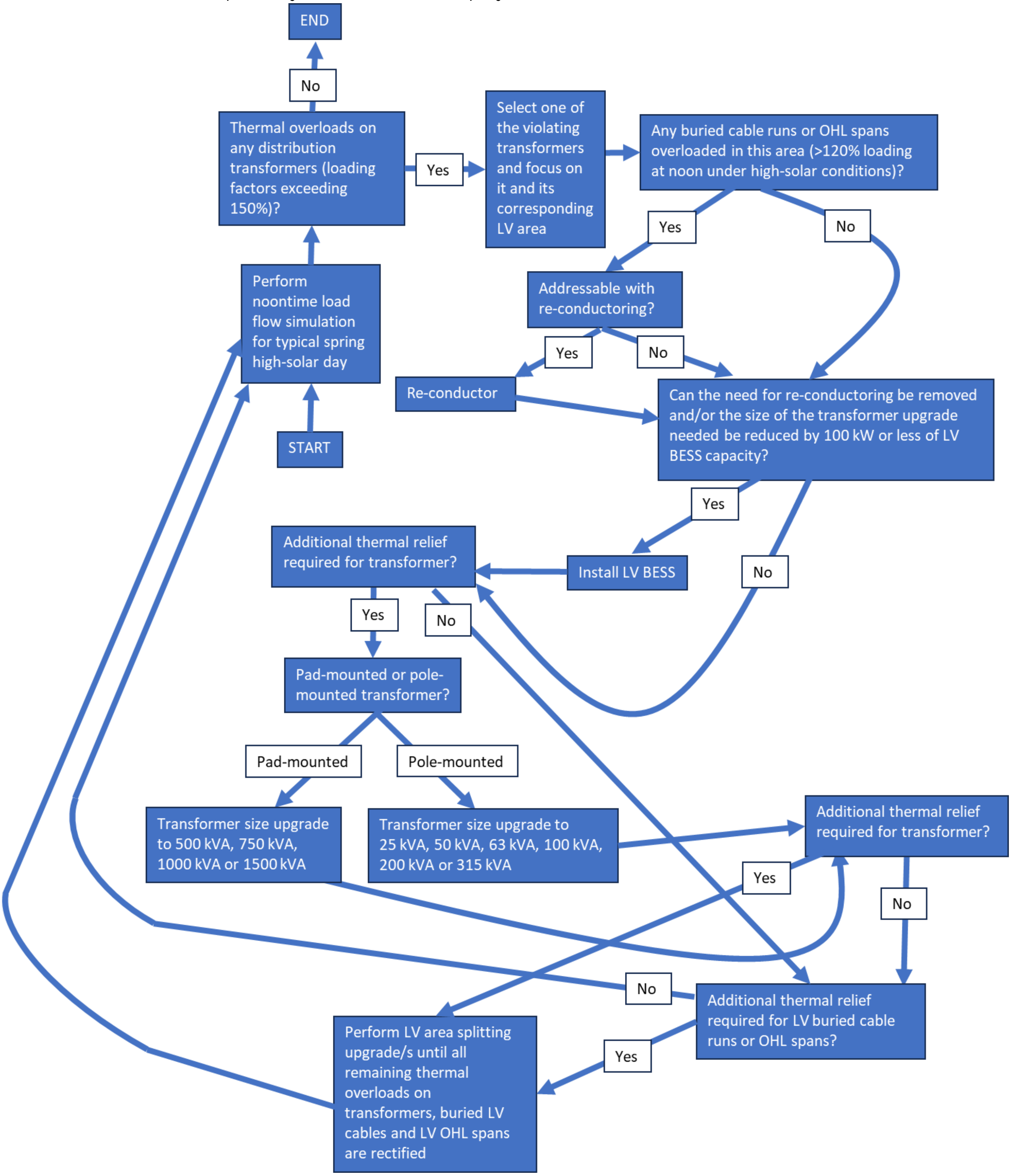

Figure 14. Similar decision trees for the LV BESS solution pathway in case 1b and the traditional network solutions pathway are shown in Appendix A.

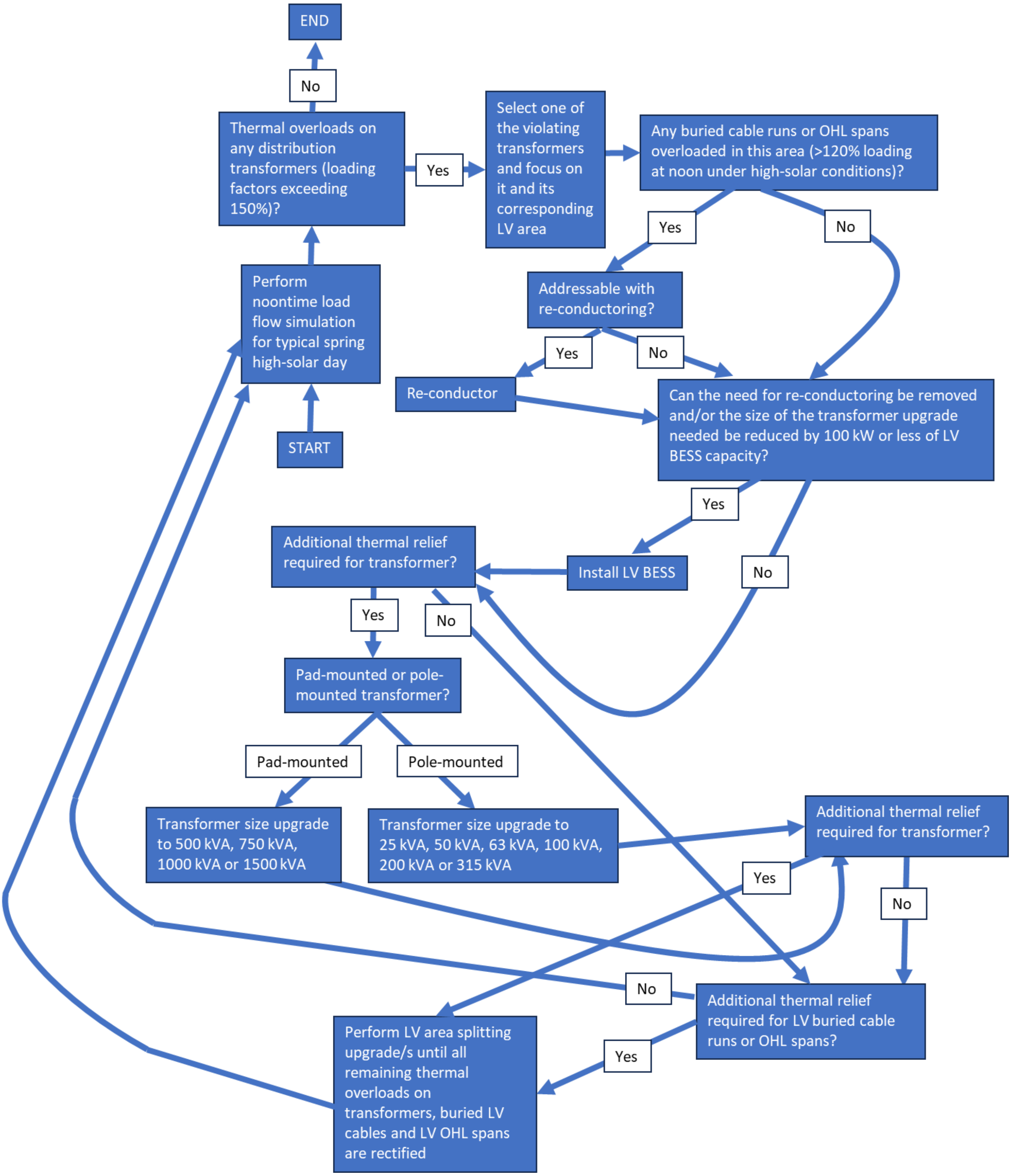

Figure 14 – Decision tree for selection and sizing of solutions to thermal overloads on LV networks and their distribution transformers in the LV BESS solution pathway in cases 1, 1a and 2

5.3 Methods for selecting and sizing solutions to LV network voltage magnitude issues

In case 2, voltage violations in the LV networks were also rectified. The standard to which Australian DNSPs are held when it comes to steady-state voltage limits is AS61000.3.100-2011 [16]. This standard requires that RMS phase to neutral voltage magnitudes that fall below 216 V or above 253 V do not persist at any customer connection point. Since year-long simulations were not performed in this project, this criterion was applied by making the following approximations:

- Seasonal variations in the profile of solar intensity occurring across the peak sunlight hours in the middle of a clear-sky day are negligible
- In Queensland, Australia, it is reasonably typical that solar irradiance levels will be high on all seven consecutive days of some weeks of the year

Using the first of these two assumptions implies that high solar conditions in spring facilitate an adequate assessment of voltage magnitude limit violation risk in any of the seasons of the year. Using the second assumption it is additionally evident that any LV bus exceeding 253 V in a given half-hour period of the representative high solar spring day that has been simulated in this project will be likely to exhibit overvoltage in all seven of the instances of the that half-hour period in a week exhibiting high solar conditions throughout all seven days. Since a period of half an hour corresponds to approximately 2.08% of the time in any given day, this therefore implies that a bus exhibiting overvoltage for a particular half-hour period in the typical high solar spring day simulated would also be exhibiting overvoltage for roughly 2% of the time across that high solar week. This then implies that voltage magnitude limit violations occurring in approximately 2.5 separate half-hour simulations would be adequate to declare violation of the standard. In the interests of keeping the study conservative, this was rounded down to a requirement that upper voltage magnitude limit violation in only two separate half-hour time periods of the representative spring high solar day would be adequate to necessitate rectification. This criterion was also used for undervoltage violations; average half-hour phase to neutral voltages falling below 216 V for two half-hour periods of the simulation were also assumed to require rectification. The same reasoning is applicable for undervoltage violations and both of the input assumptions for overvoltages are still applicable, but additionally it must also be assumed that:

- The size of the evening load peak for a summer high solar day is relatively large compared to other types of days of the year, because the greater heat flux occurring during that day would often result in more air-conditioning use in the evening

This assumption is also supported by the shape of the baselined load curves for the modelled zone substation area, which was shown in Figure 6 in section 2. Referring to that figure, the evening load peak of the present-day zone substation area represented by the network model is approximately 5 MW higher in summer than in any other season, hence this daily curve was used for the assessment of worst-case evening undervoltages in general.

Wherever possible, overvoltage violations during the middle of the day were addressed by lowering the static tap-changer position on the distribution transformer, as long as this did not result in undervoltage violation during the evening period. Similarly, undervoltage violations occurring during the evening peak were addressed wherever possible by raising the tap-setting on the transformer, as long as this did not induce overvoltage across the midday period. Wherever these solutions were not possible, alternative rectification measures dependant on the solution pathway were implemented. Since it was not possible to estimate the effectiveness of a given size or instantiation of these rectification measures for voltage constraints, solution adequacy was determined by repeated trial-and-error load flow simulations. Note also that the costs for field personnel to travel to the distribution transformers and implement tap-setting changes on them were not recorded as these would be very similar in all three solution pathways and they would be significantly smaller than the costs required for subsequent rectification measures applied for voltage constraints.

In the traditional network upgrades and MV BESS solution pathways, either LV area splitting or re-conductoring was used to rectify voltage issues. The choice between these was made based on which method would most reliably rectify the issue for the lowest cost. In some instances, it was found that both types of solution were needed. LV area splitting upgrades in OHL areas were assumed to require a new 315 kVA transformer in general; this assumption was based on the assertion that the DNSP would want to avoid having to return to this area and upgrade the transformer shortly after the initial upgrade. For underground LV areas, it was assumed that the splitting upgrade would require a new 500 kVA transformer in general. In cases where some MV buildout would be required to implement the splitting upgrade, repeated simulations were performed to determine the bus nearest to the existing MV network at which the new transformer could be installed while still rectifying the voltage issue, so that the length of the MV buildout could be minimised and over-estimation of the cost of this could be avoided.

In the LV BESS solution pathway, LV areas that were found to be exhibiting voltage violations that couldn't be rectified using static tap-setting alterations were addressed using LV STATCOMs. The power capacities of the STATCOMs available were assumed to be limited to the same values that the BESS installations had been limited to i.e. 20 kVA, 31.5 kVA, 50 kVA, 63 kVA and 100 kVA. The STATCOMs were placed at the remote ends of the LV feeders in general to maximise their impact on local voltage magnitude. For some LV feeders, it was found that the size of the STATCOM needed to keep the local voltage magnitudes acceptable had to increase across the five-year time periods of the study. The simplifying assumption was made for these feeders that the old unit could be moved to another useful location elsewhere in the network and thus that the financial value for it could be subtracted from the cost for the new unit. This is similar to the cost accounting assumption that had been applied to transformers, except that de-valuation of the STATCOM due to asset aging was not estimated. This approximation was necessary because the time periods in question are relatively short and the typical service life for STATCOMs in power system distribution networks is not yet well established.

In the simulation of the LV BESS solution pathway in case 2, LV BESS installations were assumed to be injecting active power throughout the evening period as this simplified the analysis to some degree. In reality, a combination of active and reactive power that would be dependent on the solar irradiance and load conditions that had occurred throughout the day would be injected by each of the LV BESS installations so that the local network could be optimally supported in avoiding thermal and voltage violations. Determination of such optimal BESS functionality for each location in which one of these devices was installed in the network was however deemed to fall outside of the scope of this study. Furthermore, the assumption of purely active power injection in the evening, which might occur after a day of full solar irradiance, is also justified on the grounds of producing a conservative worst-case scenario with respect to voltage control of the LV networks. It was determined through a sensitivity study that at the majority of LV locations in which BESS installations were applied in this study, the local voltage is easier to control using reactive power than using active power. This finding is expected to be attributable to the fact that the X/R ratio is greater than unity at most locations in the LV networks modelled in this project. Hence, the assumption that the LV BESS installations would be offloading active power which they had absorbed throughout the day corresponded to the most challenging situation with respect to LV network voltage magnitude control.

Where the support provided by a 100 kVA STATCOM was found to be inadequate to rectify an LV voltage issue in the LV BESS solution pathway, the issue was instead rectified using the cheapest option out of re-conductoring and LV area splitting. As in case 1, the cumulative capacity of BESS and STATCOM installations on any one LV feeder was also not permitted to exceed 100 kVA in general. As discussed previously, the reasoning for this is the assumption that the DNSP would want to avoid the risk of severe thermal overload in the case of equipment or controller malfunction events.

In case 2, the additional costs that would be associated with rectifying thermal overloads of LV conductors that had been found to be occurring in the LV areas in which voltage issues were to be rectified were only recorded if they occurred in different years in the traditional network upgrades and LV BESS solution pathways, or if different measures were the most cost effective to rectify them. In other words, LV re-conductoring costs that were identical under both solution pathways were not recorded as these would not provide useful differentiation between the costs of the three solution pathways. This simplification to the costing methodology for case 2 was made in the interests of saving time and effort, but also because the nature of these costs had already been largely captured by the costings recorded for case 1.

Careful checks on expected ten-year LV conductor loading factors were carried out in order to identify feeders for which emerging overloads meant that the additional current injected as a result of STATCOM installation would render it an infeasible option for voltage magnitude issue rectification. So that these checks could be performed more efficiently than the LV conductor overload identification process than had been applied in case 1, the average values of maximal phase loading factors at which overload was found to emerge within the next ten years were calculated using the data that had previously been collected for that earlier case. The average values of maximal phase loading factor reduction that would be needed to prevent ten-year emergent overloads were also identified using the data from case 1. Distinct values of these averages were identified for only three groups of LV conductors; 240 mm^2 aluminium buried cable, 120 mm^2 buried aluminium cable and all of the OHL types. These averages are shown in **Table 5**.

Table 5 – Maximal phase loading factor statistics for LV conductors gathered from case 1 data

	LV buried 240 mm^2 aluminium cable	LV Buried 120 mm^2 aluminium cable	All OHL Types
Average maximal phase loading factor corresponding to ten-year overload (%)	110	95	96
Average maximal phase loading factor reduction required to prevent ten-year overload (%)	84	58	62

The averages shown in **Table 5** were used to identify which LV feeders that had seen STATCOMs installed would also be expected to see thermal overloads occur within ten years. Simulations with the STATCOMs active were used to identify their loading factors and these were then compared to the applicable values in the first row of **Table 5**. All of LV feeders with STATCOMs that were identified as also having thermal violations expected to emerge within ten years were found to only have overload emergence expected throughout the midday period of the high solar spring day and only if the STATCOMs were active during that period. In other words, feeders were not found to have ten-year thermal overload also expected during the evening load peak period. This in turn meant that STATCOM application was often still feasible, as down-tapping of the transformer was often sufficient to remove overvoltages from the midday period and meant that injection from the STATCOM was only needed to control the local voltage magnitudes during the evening. In the limited number of LV feeders for which STATCOM support would be needed to rectify voltage issues during the midday period, STATCOM installation was avoided and LV re-conductoring or LV area splitting was utilised in the LV BESS solution pathway instead.

The figures shown along the bottom row of **Table 5** also provide further insight into the reason that re-conductoring was generally found to be inadequate to remove thermal overloads on LV conductors in case 1. The amount of loading factor reduction needed to prevent ten-year overloads for buried 120 mm^2 aluminium LV cable is larger than what is achieved by upgrading to the maximum LV buried cable size of 240mm^2 aluminium cable. Similarly for most OHL types, a reduction of 62% is also too high to achieve. For the typical rating of Mars conductor for example, upgrade to the maximum grade of Moon only results in the loading factor being effectively reduced by approximately 35%.

The hierarchy of decisions used to make LV upgrades for voltage violations in case 2 is depicted in the decision tree shown in Figure 15 for the LV BESS solution pathway. A similar decision tree for the traditional network upgrades and MV BESS solution pathways is shown in Appendix A.

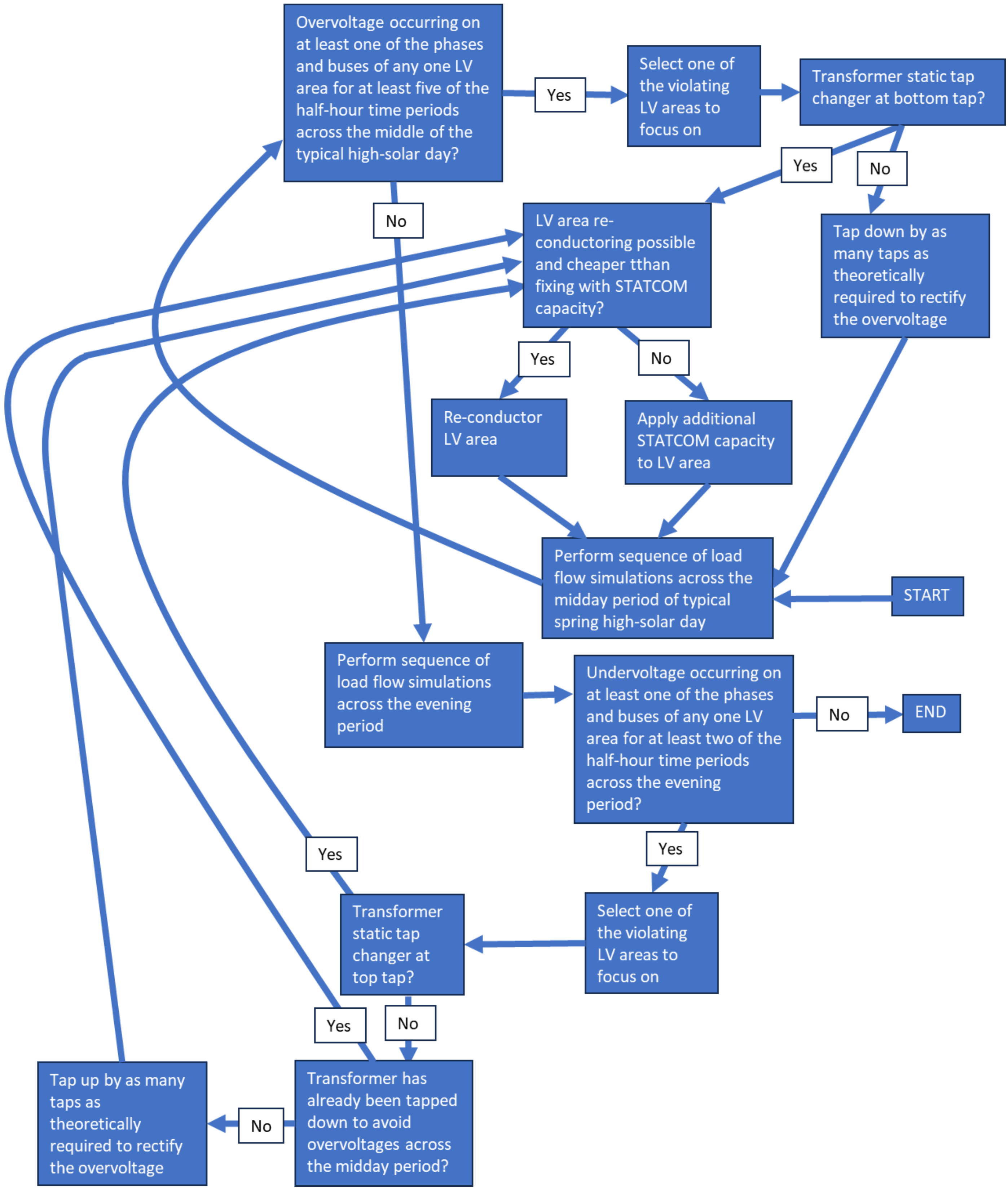

Figure 15 – Decision tree for selection and sizing of solutions to voltage magnitude violations on LV networks in the LV BESS solution pathway in case 2

5.4 Sensitivity study demonstrating MV STATCOM ineffectiveness

While MV STATCOMs could have been applied to rectify voltage magnitude issues in the MV BESS solution pathway in case 2, this was avoided because the effectiveness of STATCOMs placed in the MV network at controlling LV network voltages is lower, thus they would have exhibited poor cost performance as solutions to LV voltage magnitude issues. As a demonstration of this fact, a brief sensitivity study was conducted. The network model was prepared with a moderately large cumulative volume of PV installations equivalent to approximately 5 kW per household distributed randomly and uniformly across all customers. It was assumed that only 50% of the PV inverters had volt-watt and volt-var functions active, which corresponds with an assumption that the level of compliance with AS4777.2 is relatively poor, which makes voltage control across the network more challenging. The upstream voltage source representing the wider distribution network was also configured as if the power transformers at the zone substation were all saturated at their highest taps. The network model was then simulated at noon in spring under high solar conditions with no STATCOMs or other voltage or thermal rectification solutions applied.

Following this, a cumulative STATCOM capacity was applied across the model in two different ways. Firstly, ten STATCOMs of 450 kVA size were installed at the points two-thirds of the way along each of the ten MV feeders, then, in the second instance, STATCOMs sized at 50 kVA each were installed at 90 different locations exhibiting the worst overvoltages at noon across the LV feeders of the model. The findings for simulations at noon in spring were that phase to neutral voltages would occur on approximately 14.4% of all LV buses without any STATCOMs present, 6.4% of all LV buses with STATCOMs distributed across the MV level of the network and 4.8% with STATCOMs distributed across the LV level of the network. On the other hand; voltage magnitudes across the MV network are reduced somewhat more effectively by MV STATCOMs than LV STATCOMs, but this is less relevant as the critical issues in voltage magnitudes occur in the LV network where customers are connected. The greater effectiveness of LV STATCOMs at controlling LV network voltages are demonstrated by the heatmap of one of the LV areas in the model that is shown without STATCOMs, with MV STATCOMs and with LV STATCOMs in Figure 16, Figure 17 and Figure 18 respectively.

Figure 16 – Voltage magnitude heat map of one of the LV areas in the network model at noon in spring given 5 kW per household of average PV density, 50% compliance with AS4777.2 and no rectification measures for voltage magnitude issues applied (red corresponds to 250 V maximal phase to neutral voltage while green corresponds to 240 V maximal phase to neutral voltage)

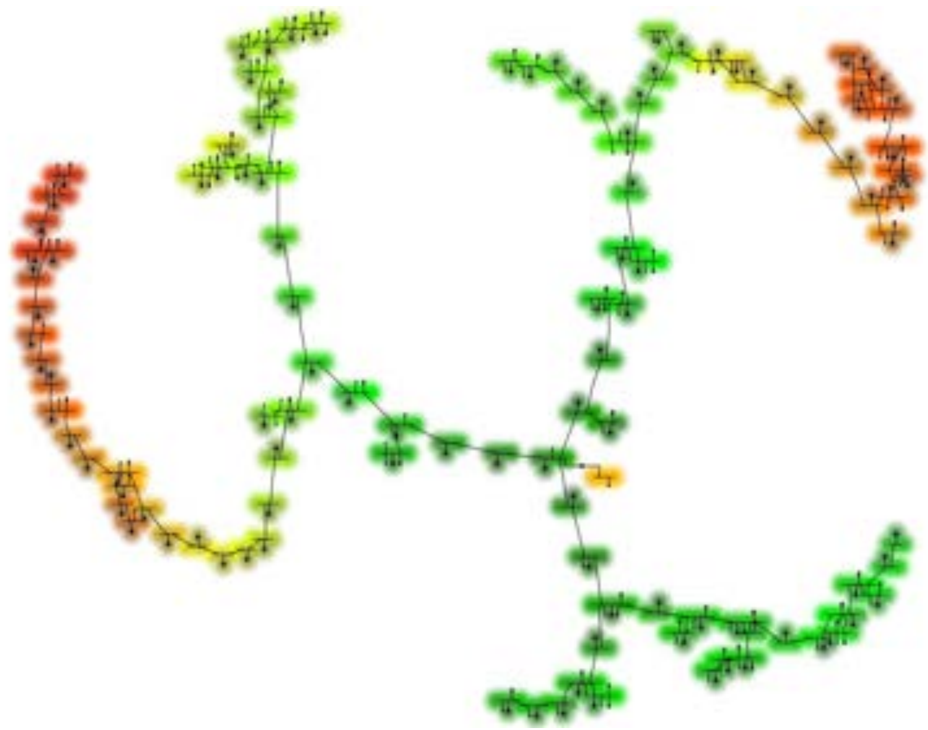

Figure 17 – Voltage magnitude heat map of one of the LV areas in the network model at noon in spring given 5 kW per household of average PV density, 50% compliance with AS4777.2 and 4.5 MVA of STATCOMs distributed across the MV network (red corresponds to 250 V maximal phase to neutral voltage while green corresponds to 240 V maximal phase to neutral voltage)

Figure 18 – Voltage magnitude heat map of one of the LV areas in the network model at noon in spring given 5 kW per household of average PV density, 50% compliance with AS4777.2 and three 50 kVA LV STATCOMs applied in this LV area (red corresponds to 250 V maximal phase to neutral voltage while green corresponds to 240 V maximal phase to neutral voltage)

5.5 Solutions for MV thermal overloads

In committing to a long-term upgrade investment strategy, a DNSP must balance several competing considerations. On the one hand, delaying investments into the future wherever possible is preferable because it is easier to justify to the regulator and it also avoids straining the labour capacity of the organisation beyond what is sustainable. On the other hand, delaying upgrades that will inevitably become a necessity at some point in the future could also create a risk of simply shifting a period of strain on the labour resources of the organisation from one point in time to another without reducing its severity. It is therefore sound planning practice to identify the upgrade projects that will be most likely to be a necessity in the long term, to prioritise and sequence them according to customer need and logistical capability of the organisation and to then spread the trajectory of investment that will be needed for these projects out over time as smoothly as possible.

The conflicting considerations outlined above make it difficult for any given DNSP to settle on planning policies for a newly emerging problem such as widespread thermal overload in the distribution networks; particularly when the nature with which such a problem will emerge might be difficult to predict accurately at every location in the network. The fact that no historical precedent for this particular problem exists makes the accuracy of such a prediction even more difficult. Given that this is the case, it was assumed in this project that the DNSP would not use ten-year forward extrapolation in their sizing for MV network upgrades. It was assumed instead that they would simply implement rectification measures that were adequate for each individual five-year time period, but that they would at least implement these as soon as the thermal loading of any given MV buried cable run or OHL span exceeded 90%. Reduction of the threshold for triggering of MV network upgrades is appropriate because the much larger numbers of customers that they feed results in commensurately higher risk for the DNSP if they become damaged and produce network outages.

In the traditional network upgrades solution pathway, thermal overloads in the MV network were addressed wherever possible using re-distribution of load between the ten MV feeders in the modelled zone substation area via opening and closing of available switches. Where upgrades such as these were possible, a figure of $5000 AUD was used to represent the labour cost to open and close any number of switches to relieve one MV feeder. This was assumed to be the preferred option in general for this solution pathway as it is by far the most cost effective. Where this was found to be infeasible for MV OHL spans, re-stringing to the higher conductor grade of Moon was applied. Furthermore, in cases where the rating associated with Moon configured to operate at a maximum temperature of 75°C was insufficient, upgrades to Moon capable of operating at 100°C were applied. The latter type of upgrade was assumed to incur a cost per length that was only 30% as large as that for the former. Uprating the maximum operating temperature of a given grade of conductor does not involve conductor replacement but instead involves only re-tensioning of existing conductors to support the greater levels of conductor tension needed to reduce sag, occasional refitting of crossarms higher up a given pole and where those previous two methods are not feasible, occasional installation of additional intermediate poles to increase ground clearance.

In the instances where overloads on MV buried cable runs could not be addressed via re-distribution, a new run of MV 400mm^2 aluminium cable was built. Buried cable runs are not usually installed in direct electrical parallel (i.e. bonded to each other both upstream and downstream) as this creates the risk of uneven current sharing due to impedance mismatch and eventual thermal runaway of one of the two cables that would be undetectable. Since this is the case, it was assumed that in these types of upgrades, the existing lower grade of buried cable would simply be disconnected and abandoned, unless it could easily be reused as part of an alternative feeder. Note that the cost to remove the existing cable run would be significant, thus this would seldom be carried out in practice. Underbore runs that cut under roads and runs that align with a main road were assumed to have had spare conduits built with them in general; the cost of installing the new cable was assumed to be 35% cheaper in such cases as trenching would not be needed.

Occasionally in the latter years of the study it was found that the rating of MV 400mm^2 aluminium cable would not be sufficient to avoid overload on a given existing run of MV buried cable. Since running buried cables in electrical parallel is avoided in general, another augmentation strategy was needed in these cases. The solution employed was that longer runs of cable and OHL were installed in spatial parallel with the existing feeder until a location downstream was reached at which the BAU maximal current would not overload MV 400mm^2 aluminium cable. The existing MV feeder was then split so that customers downstream of this location would be served by the new feeder while those upstream would continue to be served by the existing feeder. Where possible in some instances, the length of new MV feeder needed was reduced by making a connection onto a neighbouring MV feeder with spare thermal capacity.

The mix of buried cable and OHL for the new section of MV feeder created during MV feeder splitting upgrades was assumed to reflect that of the existing feeder with which it was built in spatial parallel. However, in many real-world cases, this might not be practically feasible. For example, a new section of OHL might need to be built on another street rather than on the other side of the street for the existing feeder, or a new run of buried cable might need to have a new conduit installed elsewhere due to the need to avoid the additional costs associated with digging up and then re-constructing the driveways of residential customers. In some real-world cases, construction of large additional sections of MV feeder may be altogether infeasible. Considerable additional effort would have been required to include considerations like these in this study, however. Furthermore, input information that would have facilitated such accurate and detailed hypothetical construction planning for new MV feeder projects was also not available. In any case, assuming that the new sections of MV feeder could run in spatial parallel with the existing ones was deemed to be acceptable as it corresponded to erring on the side of underestimating the costs of the traditional network upgrades solution pathway. The same intention was also used to justify the assumption that the new MV buried cable runs that would be built as part of these MV feeder splitting upgrades would all have spare conduits on the existing feeder available, so that trenching costs did not need to be included.

In the MV and LV BESS solution pathways, overloads on the MV network that could not be rectified using redistribution across the MV feeders were rectified using BESS capacity in general, rather than with re-conductoring or MV feeder splitting. These BESS installations were applied in locations that were electrically further out from the zone substation than the thermally overloaded MV feeder span or run. In the LV BESS solution pathway in particular, additional volumes of BESS power capacity beyond what was feasible for displacing traditional network upgrades in the LV areas were also needed to avoid MV network overloads. These BESS installations are referred to as “non-LV-upgrade-displacing” BESS installations in this report. These installations were placed in a targeted fashion in the LV BESS solution pathway so that MV thermal overloads would be avoided i.e. they were placed in LV areas connected in the MV network that were downstream of the emerging overload being targeted.

5.6 BESS energy capacity sizing

The costs for BESS installations would of course also be dependent on the storage depths needed for the batteries. Additional simulations were therefore carried out for all of the hours in the typical high solar spring day in which substation overload would have occurred without BESS support. The simulations were carried out in an iterative fashion. The charging powers of all BESS installations present in each of the years that they were needed were repeatedly varied by small increments within the range of 0% to 100% until the cumulative zone substation apparent power flow was limited to within 100 kVA of the 42000 kVA limit needed to avoid an upgrade. The loading factors on all MV conductors and/or distribution transformers and LV conductors in areas in which upgrades had been applied were also checked and found to be below the applicable overload values when the zone substation limit had been respected.

The cumulative BESS charging power values in each of the additional simulations were then used to calculate the cumulative BESS energy capacity requirements in both the MV and LV BESS solution pathways. These energy requirements were then factored into the cost estimates for both of the BESS solution pathways.

5.7 Simulation modelling implementation of the zone substation upgrade

For the modelling of the zone substation upgrade in the traditional network upgrades solution pathway, it was assumed that five of the ten MV feeders supplied by the existing substation would see a proportion of their load diverted to the new substation as a result of the upgrade. This is a relatively optimistic assumption with respect to the effectiveness of the zone substation upgrade. In many cases, the locations with land that can be most readily procured for the new substation site would not necessarily align with the direction away from the existing substation from which the majority of the existing MV feeders emanate. This in turn would mean that the proportion of MV feeders supplied at the existing substation that could be feasibly offloaded by the new substation may often be less than half. The intention for this study however is to make assumptions that are optimistic as far as traditional network solutions are concerned and pessimistic as far as non-traditional network solutions are concerned, whilst still being relatively realistic. In alignment with this intention, it was also assumed optimistically that the MV feeders that would be offloaded by the zone substation upgrade would be connected to a new zone substation via additional MV feeder buildout that is only as long as approximately one quarter of their existing lengths and that approximately the outermost half of their existing lengths would be transferred into the new substation system.

Which particular set of five MV feeders out of the existing ten would be relieved by the zone substation upgrade is unknown. This assumption was however found to have a significant effect on the costs for MV network upgrades, particularly MV feeder splitting, in the traditional network solution pathway. The MV network upgrades costs were therefore calculated for two different instances of this assumption; one in which it was assumed that the five feeders emanating in a north-westerly average direction from the substation were relieved and one in which it was assumed that the five feeders emanating in a south-easterly average direction were relieved. The costs calculated using these two different instances of the MV feeder relief assumption were then averaged together before being added to the overall costs for the traditional network upgrades solution pathway.

6 Cost assumptions

6.1 Zone substation upgrade cost

A variety of costing assumptions were used in the studies for this report. Of these, the upgrade cost for the zone substation was by far the highest singular network upgrade cost included. This upgrade was assumed to cost $50 million AUD. The justification for the size of this cost is based on two critical assumptions around the nature of its implementation:

1. Due to space limitations, building out the thermal capacity of the existing substation site would be infeasible, and a new site located elsewhere would have to be procured for this purpose. It is true that many substations can be augmented; higher rated transformers for example can often be used to replace the existing older ones. However, many such substations have switchgear that will not accept the higher fault level that usually results from installing larger transformers and the cost of replacing both transformers and switchgear, in a brownfield situation, then becomes exorbitant. In such cases the replacement substation is the cheaper option. Based on the actual substation involved in this study, which is typical of many older suburban substations, the latter case is the more typical and realistic situation; hence that has been used as the determinant for the type of upgrade represented in this study.
2. Suburbs neighbouring the one for which the zone substation is to be upgraded do not contain any existing substation sites with spare space that would facilitate low-cost buildout of additional thermal capacity. This is also typical of older, well-established suburban areas.

With the exception of a subset of unique locations, both of these assumptions apply to most of the zone substation sites in the Brisbane area. Since the intention of this study is to identify a cost-comparison between traditional and non-traditional network augmentation options for dealing with high DER penetration that is applicable to the typical zone substation area in this network, both of these assumptions have been adopted in this study. Their combination implies that the cost for the new substation that realises relief for the existing one will be driven up by all of the following factors:

- Site acquisition
- Environmental assessment report
- Community consultation
- Civil works to bench the site
- Earth grid installation and testing
- Fencing and internal roadways (with strength sufficient to host a crane for transformer delivery)
- Foundations for major equipment
- Conduit installation
- New transformers
- Demountable building with switchgear
- Internal cabling
- Protection & comms
- External 11 kV works to modify the network and "cut in" the new substation
- External 33 kV works to supply the new substation

- Commissioning procedures

Owing to the variations which can exist in the unique constraints for each site, the costs outlined above can vary significantly from project to project. The cost of the zone substation upgrade was therefore also assigned a margin of ±30%, in alignment with representative present-day planning estimates for upgrades to zone substations.

6.2 Other cost assumptions

The present-day price for a 100 kVA inverter was based on typical inverter costs for this size category, with the assumption that volume production has also reduced the manufacturing costs to some degree. The current battery price was based on the cost for a 100 kW, 2.3 hour CATL unit. Prices for new inverters were assumed to scale linearly with rating, while prices for new batteries were assumed to scale linearly with both power and energy ratings. Furthermore, it was assumed that prices for batteries will decrease gradually over the years of the study in proportion to the normalised trends indicated by the data in [17]. Prices for inverters however were assumed conservatively to remain fixed indefinitely.

Costs for new distribution transformers, new LV and MV buried cable runs and OHL spans as well as the cost of installation labour were provided by EQ. In the particular case of distribution transformer being upgraded to a larger size, the value of the existing transformer was subtracted from the cost of the new transformer as this asset would typically be warehoused and then employed elsewhere in the network. Data on the age of existing distribution transformer assets in the modelled area was not available at the time of completing this project. A generic value depreciation factor corresponding to an age of 15 years at the time of replacement and a usable service life of 50 years was therefore assumed for all transformers replaced in the study.

Distribution network assets such as buried cable, overhead conductors and poles etc. are not re-usable after replacement. Reduction of the costs of upgrades for these types of assets due to re-utilisation of existing assets was therefore not implemented. Note that the costs for upgrades to poles so that they can support the weight of a new pole-top transformer and installation of concrete pads for new pad-mounted transformer installations were both assumed to be fixed costs that account for the cost of labour to install the new transformer and that are independent of its capacity.

It is also noted here that while the adequacy of re-conductoring of sections of buried LV cable and LV OHL spans that would occur in some of the LV area upgrade projects modelled in this project was noted when it was identified, so that alternative solutions were then not applied; the costs for these solutions were not recorded. The reason for this is that where LV thermal violations could be adequately relieved by upgrades to LV conductor sizes, this would most often be the cheapest solution in all three of the solution pathways investigated in this study. This property makes the costs for LV re-conductoring a poor differentiator between the costs of each of the three solution pathways and therefore not worth the effort of precise quantification. In other words; since LV re-conductoring would be the default solution in all three solution pathways in those cases where it was identified as adequate, the cumulative costs for it in each pathway would be almost exactly the same. Furthermore, the amount of thermal relief that could be provided by LV re-conductoring was, in many cases, not sufficient to address the ten year-extrapolated constraint. The unmeasured cumulative costs of these upgrades in each solution pathway were therefore also expected to be small when compared to the costs for other types of solutions applied for LV thermal constraints.

All cost assumptions used in this project are indicated in **Table 6**.

Table 6 – Project cost assumptions

Item	Cost ($AUD)
New 100 kVA inverter	83,333
New 100 kW, 2.3 hour battery	300,000
New 100 kVA pole-mounted distribution transformer	35,000
New 200 kVA pole-mounted distribution transformer	54,048
New 315 - 500 kVA pole-mounted distribution transformer	60,000 / 315 kVA
New 500 – 1500 kVA pad-mounted distribution transformer	95,000 / 500 kVA
Pole upgrade to transformer-bearing capacity (incl. labour)	14,062
New pad-mounted transformer pad installation (incl. labour)	15,000
Upgrade LV buried cable to LV buried 240mm² aluminium cable (1 x four-core cable)	1,086 / 1 m
Upgrade LV buried cable to MV buried 240mm² aluminium cable (3 x single-core cable)	1,664 / 1 m
Upgrade LV OHL spans to LV Moon	210 / 1 m
Upgrade LV OHL spans to MV Moon	149 / 1 m
Upgrade LV OHL 25 ABC spans to 95 ABC	286
Upgrade LV OHL 95 ABC spans to double 95 ABC	286
New MV buried 240mm² aluminium cable (3 x single-core cable)	1,664 / 1 m
New MV buried 400mm² aluminium cable (3 x single-core cable)	1,574 / 1 m
Zone substation upgrade	35,000,000 – 65,000,000
MV network load re-distribution upgrade (switch opening and closing only)	5000

6.3 Cost curve estimation for cases 3 and 4

For cases 3 and 4, LV area upgrade costs were estimated using extrapolation from averages calculated for case 1, rather than applying alterations to the network model in PowerFactory and running additional load flow simulations. The LV areas were categorised as either "OHL areas" or "underground areas" depending on how they were connected to the MV network. The underground areas are composed entirely of buried cables at the LV level and are universally connected through transformers with ratings of 500 kVA or larger. The OHL areas are connected entirely through distribution transformers of 315 kVA rating or smaller. A subset of the OHL areas were found to contain some amount of LV buried cables; the costs for these areas were not used in the calculation of the average LV area upgrade costs for OHL areas because the intention for case 3 was to represent a zone substation area consisting solely of OHL networks at both the LV and MV levels. Note that the cohort of 170 LV overhead areas in the modelled zone substation area is much larger the number of LV underground areas, which is only 59.

The zone substation area studied for this project is composed of 261 distribution transformer connections. Of these, 32 are connected to commercial or light industrial customers with their own local LV networks. Of the remaining 229 transformers, 170 are connected to OHL areas while 59 are connected to underground areas. The LV network upgrades which had been identified as being necessary in each of the solution pathways in case 1 were grouped according to which of these two types of LV areas they were for. In case 3, the approximation was made that the number of LV areas that would need an upgrade in each time period would be the same as in case 1 when normalised by the number of OHL areas existing in each case. In other words, the percentages of OHL areas needing an upgrade in each time period of the study were assumed to be the same, but the set of which LV areas were assumed to be OHL areas was enlarged to include all 229 of the LV networks owned by the local DNSP. Similarly in case 4, the assumption was made that all of the 229 local DNSP-owned LV networks were underground areas, while the percentages of underground areas needing an upgrade in each of the five-year time periods of the study were assumed to be the same as in case 1. For reference, these percentages are shown later in this report in Figure 19.

The averages of the traditional network upgrade components of the costs for upgrades to OHL LV areas and buried cable LV areas were calculated separately for the traditional network upgrades solution pathway and the LV BESS solution pathway. These averages were calculated using data from all time periods for each of the two solution pathways. The costs for BESS installations were not included in the average costs for LV area upgrades in the LV BESS solution pathway because these costs were approximated as being the same in cases 3 and 4 as they had been in case 1. More precisely, it was assumed that the amount of active power that would need to be absorbed to avoid zone substation and MV conductor overload in each time period was the same in both case 3 and case 4 as it had been in case 1. This assumption was expected to still result in a reasonable estimation of overall network upgrade costs in the LV BESS solution pathway for hypothetical zone substation areas that are similar in size to the one modelled but composed entirely of OHLs or buried cables. It requires only that the overall number of customer connections and growth in average rooftop PV capacities be the same.

Note that the averages of the traditional components of the LV area upgrade costs are by definition the same for the MV BESS and traditional network upgrade solution pathways. This is the case because LV area constraints are addressed entirely using traditional network upgrade methods in the MV BESS solution pathway. The average LV area upgrade costs were then multiplied with the numbers of LV area upgrades assumed to be needed in each case and in each time period.

Changes to the costs for MV network upgrades for cases 3 and 4 were also estimated. These estimations were made simply by assuming that all of the MV re-conductoring and additional MV buildout which had been found to be necessary in case 1 would be composed entirely of OHLs in case 3 and entirely of buried cables in case 4. As with the original MV buildout costings for buried cables in case 1, the costs for these were assumed to reflect the reduced rate that would be applicable when spare conduits are present whenever the buildout did not correspond to an existing MV conductor route.

7 Upgrade scope and financial analysis

7.1 Traditional LV network upgrades scope

The number of upgrades required in each solution pathway increases gradually in each case. The proportion of LV areas requiring some kind of upgrade or upgrades in case 1 regardless of which solution pathway is adopted are shown in Figure 20 for OHL areas and Figure 21 for underground areas. Note that these figures are not cumulative i.e. the requirements for each individual five-year period of the study are shown.

It is apparent that upgrades to LV overhead areas become necessary sooner, due to their smaller distribution transformer ratings, but that upgrades to LV underground areas eventually overtake them towards the end of the study period. Note that the cohort of 170 LV overhead areas in the modelled zone substation area is much larger the number of LV underground areas, which is only 59.

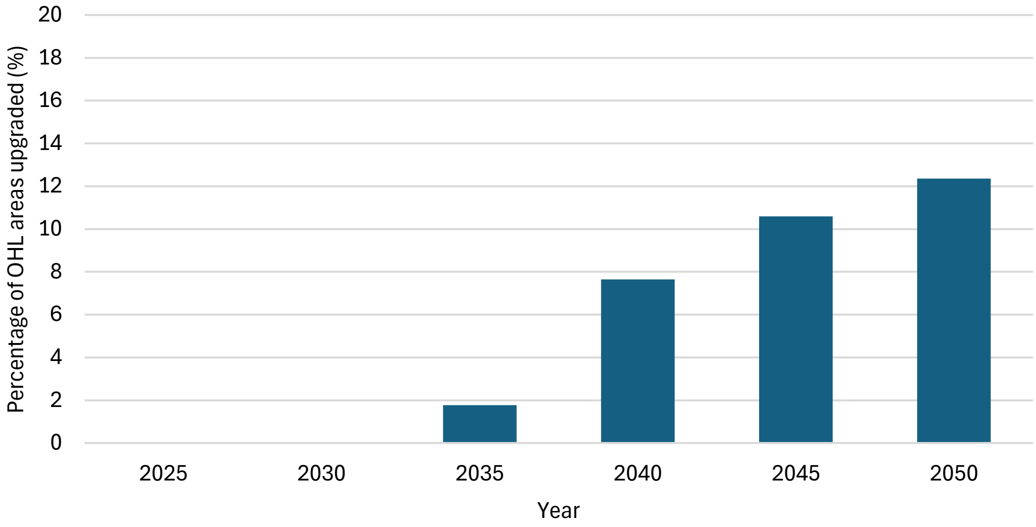

Figure 20 – Percentage of LV area upgrades in case 1 for OHL areas

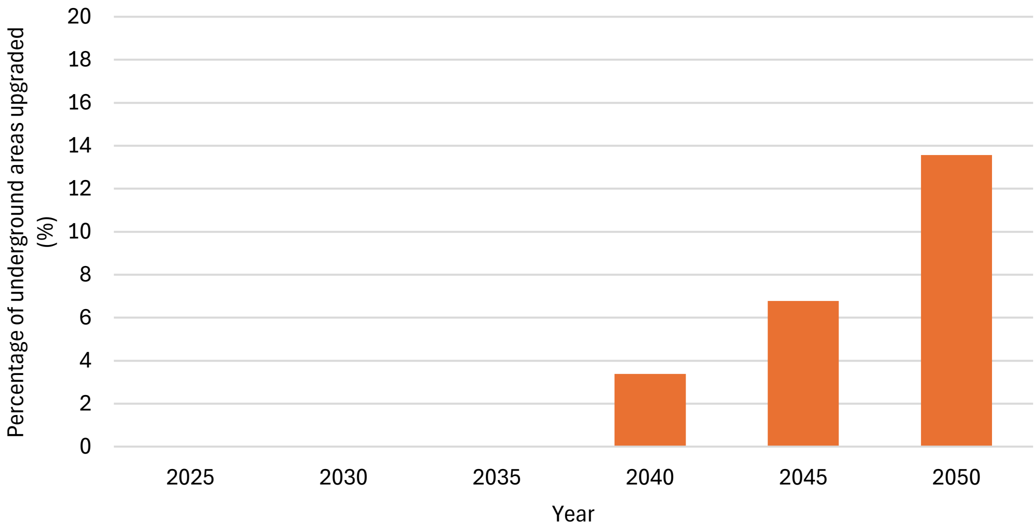

Figure 21 – Percentage of LV area upgrades in case 1 for underground areas

The numbers of LV area splitting upgrades to overhead and underground LV areas required for each solution pathway in case 1 are shown in **Table 7**. The cumulative overhead and underground MV buildout lengths required to facilitate LV area splitting upgrades are also shown. Cumulative numbers for each individual five-year period of the study are shown in black, while aggregating summations over the current and all previous five-year periods are shown in dulled grey text. Note that the numbers of traditional upgrades required for LV areas in the MV BESS and traditional network upgrade solution pathways are the same by definition.

The data in **Table 7** demonstrates the extent to which the LV BESS strategy is able to reduce the required numbers of LV area splitting upgrades and associated MV feeder buildout projects. Considerable savings in cost are associated with this; these will be shown in one of the later subsections of this section. A table showing the requirements for LV area splitting upgrades for each solution pathway in variation case 1a is also shown in Appendix C. The required numbers of LV area splitting upgrades in all three solution pathways are generally lower under this variation case.

Table 7 – LV area splitting requirements for each solution pathway in case 1

Year	2025	2030	2035	2040	2045	2050
Number of LV area splitting upgrades to overhead areas						
LV BESS solution pathway	0 (0)	0 (0)	1 (1)	7 (8)	2 (10)	16 (26)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	4 (4)	18 (22)	14 (36)	28 (64)
Number of LV area splitting upgrades to underground areas						
LV BESS solution pathway	0 (0)	0 (0)	0 (0)	3 (3)	6 (9)	22 (31)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	5 (5)	10 (15)	28 (43)
Lengths of overhead MV buildout for LV area splitting upgrades (km)						
LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.07 (0.07)	0.08 (0.15)	0.50 (0.65)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.17 (0.17)	0.30 (0.47)	0.12 (0.59)	0.50 (1.09)
Lengths of underground MV buildout to facilitate LV area splitting upgrades (km)						

LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.14 (0.14)	0.58 (0.72)	1.66 (2.38)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.19 (0.19)	0.87 (1.06)	2.06 (3.12)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

As was discussed and explained in section 5, LV re-conductoring was found to be universally ineffective at rectifying thermal overloads on LV conductors in case 1 and variation case 1a.

The numbers of LV area splitting upgrades to overhead and underground LV areas required for each solution pathway in case 2 are shown in are shown in **Table 8**. As LV re-conductoring also becomes useful in rectifying some of the voltage magnitude issues in case 2, the lengths of these are also shown.

It is clear from the final figures for LV area splitting upgrades shown for 2050 that more of these types of upgrades are made necessary by the requirement in case 2 to alleviate voltage magnitude issues, which was not present for case 1. In the early years of the study, the LV area splitting upgrade requirements shown in **Table 8** are generally smaller in the LV BESS solution pathway than they are in the other two solution pathways. As the years progress and the emerging voltage magnitude violation constraints start to become more severe however, limitations in the effectiveness of 100 kVAr STATCOMs, which was the largest STATCOM capacity permitted on any one LV feeder in case 2, start to become encountered. This in turn means that LV area splitting upgrades start to become necessary in the LV BESS solution pathway also. Similarly, significant LV re-conductoring requirements emerge for all three solution pathways by the end of 2050 as well.

Table 8 – LV area splitting and LV re-conductoring requirements for each solution pathway in case 2

Year	2025	2030	2035	2040	2045	2050
Number of LV area splitting upgrades to overhead areas						
LV BESS solution	0 (0)	0 (0)	2 (2)	7 (9)	3 (12)	20 (32)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	3 (3)	8 (11)	22 (33)	23 (56)	36 (92)
Number of LV area splitting upgrades to underground areas						
LV BESS solution	0 (0)	0 (0)	1 (1)	3 (4)	8 (12)	22 (34)

MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	7 (7)	14 (21)	29 (50)
Length of overhead MV buildout for LV area splitting upgrades (km)						
LV BESS solution	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.07 (0.07)	0.08 (0.15)	0.84 (1.00)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.24 (0.24)	0.64 (0.88)	0.72 (1.60)	0.45 (2.05)	0.94 (2.98)
Length of underground MV buildout for LV area splitting upgrades (km)						
LV BESS solution	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.14 (0.14)	0.67 (0.81)	1.66 (2.47)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.19 (0.19)	1.06 (1.24)	2.35 (3.59)
Length of LV overhead re-conductoring (km)						
LV BESS solution	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.31 (0.31)	0.36 (0.68)	0.48 (1.16)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.73 (0.73)	0.10 (0.83)	0.00 (0.83)	0.00 (0.83)	0.50 (1.33)
Length of LV underground re-conductoring (km)						
LV BESS solution	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.34 (0.34)	0.01 (0.34)	0.20 (0.55)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.31 (0.31)	0.05 (0.37)	0.30 (0.66)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

The numbers of new distribution transformers used for LV area splitting upgrades in each solution pathway are shown in **Table 28** in Appendix C. The sizes 315 kVA and 500 kVA are the most common. The number of transformer size upgrades for each original and ultimate size of transformer are also shown in **Table 29** in Appendix C. The total number of transformer size upgrades by the end of 2050 is 31 in the LV BESS solution pathway and 28 in the MV BESS and traditional network upgrade solution pathways. Transformer size upgrades are not preferentially displaced in the LV BESS solution pathway because more value is earned back by displacing the more expensive LV area splitting upgrades instead.

7.2 Traditional MV network upgrades scope

The lengths of MV conductor upgrades in the traditional network upgrades solution pathway for each year of the study in case 1 are shown for MV OHL spans in Figure 22 and for MV buried cable runs in Figure 23. Note again that these figures are not cumulative. Most of the MV network upgrades occur towards the end of the study period in 2050. A greater length of MV buried cable must be upgraded or built-out compared to MV OHL. This is the case because all of the MV feeder sections that enter the zone substation itself, where physical space is limited and where the largest accumulations of excess PV generation occur, are buried cables.

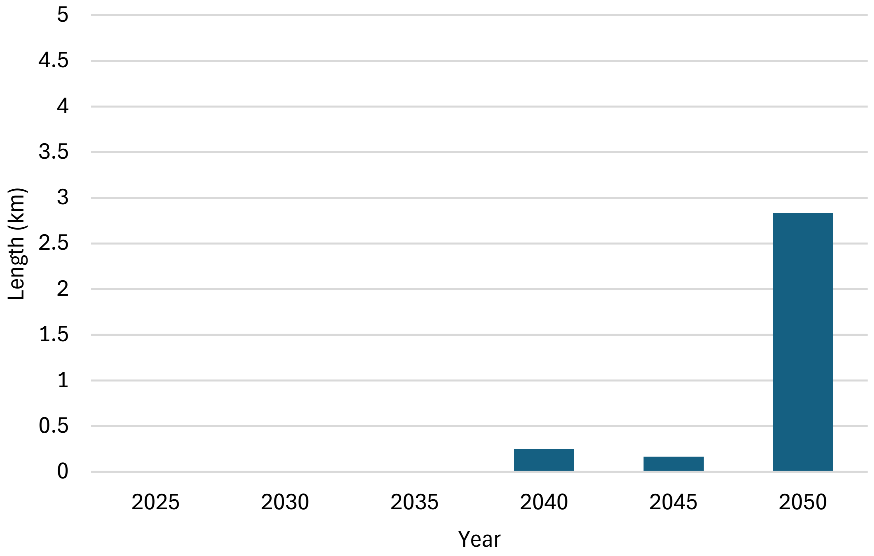

Figure 22 – Length of MV OHL upgrades or buildout to facilitate MV feeder splitting in the traditional network upgrades solution pathway in case 1

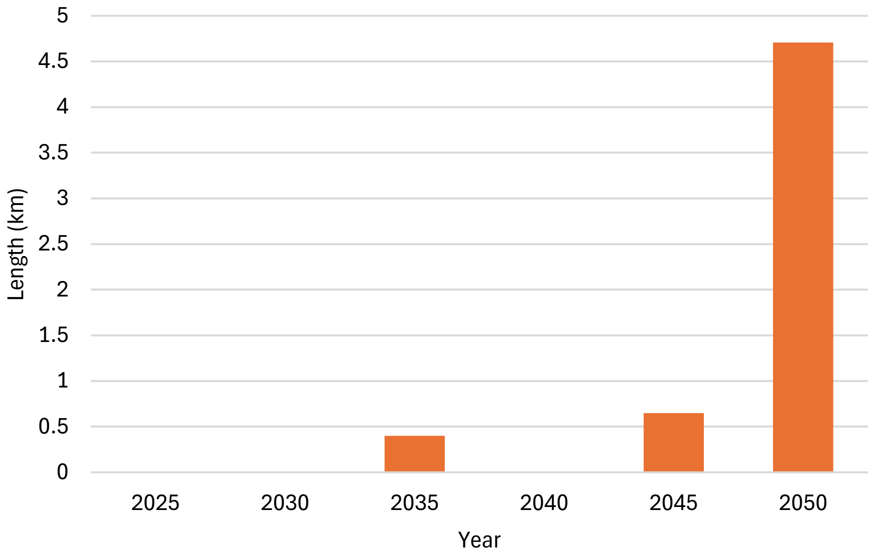

Figure 23 – Length of MV buried cable upgrades or buildout to facilitate MV feeder splitting in the traditional network upgrades solution pathway in case 1

The lengths of MV feeder re-conductoring and buildout to facilitate MV feeder splitting in each of the solution pathways in case 1 are shown in Table 10. Note that as is the case for **Table 7**, cumulative numbers for each individual five-year period of the study are shown in **Table 11** in black, while aggregating summations over the current and all previous five-year periods are shown in dulled grey text.

Neither of these two types of investments in MV conductor capacity are required in the MV or LV BESS solution pathways as the thermal overloads that would drive them are rectified entirely using BESS capacity. As discussed in section 5, requirements for MV feeder re-conductoring and/or buildout in the traditional network upgrades solution pathway are staved off initially by re-directing power flows onto adjacent MV feeders in some cases. Two opportunities to do this without incurring MV conductor costs are utilised in case 1 in the traditional network upgrades solution pathway. In 2035, some load is transferred from MV feeder 1 to MV feeder 8, while in 2040 some load is transferred from MV feeder 6 to MV feeder 9 while some more load is transferred from MV feeder 9 to MV feeder 10, as only the latter has significant spare capacity. The first of these two MV feeder load transfer operations requires however that 400m of underground MV cable be built. Beyond 2040, MV feeder thermal overload relief can no longer be achieved in case 1 in the traditional network upgrades solution pathway without significant MV feeder re-conductoring. Requirements for MV feeder buildout, with significant associated costs, also emerge in 2050.

The required lengths of MV feeder re-conductoring and buildout to facilitate MV feeder splitting upgrades for variation case 1a is shown in Table 9 in Appendix C. Notably, the lengths of MV re-conductoring are significantly shorter in the traditional network upgrades solution pathway and the requirements for MV feeder splitting upgrades to be performed no longer occur within the study period. This creates significant cost savings for the traditional network upgrades solution pathway that will be shown in later subsections of this section.

Table 10 – MV feeder re-conductoring and splitting requirements for each solution pathway in case 1

Year	2025	2030	2035	2040	2045	2050
Lengths of overhead MV re-conductoring (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.25 (0.25)	0.16 (0.41)	0.96 (1.37)

Lengths of underground MV re-conductoring (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.40 (0.40)	0.00 (0.40)	0.65 (1.05)	1.21 (2.26)
Lengths of overhead MV feeder buildout to facilitate MV feeder splitting (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	1.36 (1.36)
Lengths of underground MV feeder buildout to facilitate MV feeder splitting (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	1.99 (1.99)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

7.3 STATCOM and BESS upgrade scopes

The BESS installation requirements in case 1 for each of the BESS solution pathways are shown in **Table 11**.

The MV BESS solution pathway places a slightly higher requirement on cumulative BESS energy capacity than the LV BESS solution pathway does. On the other hand, the LV BESS solution pathway demands slightly higher volumes of overall BESS power capacity. Note that the latter is not the case simply because the resolution of more constraints are targeted in the former solution pathway; prevention of zone substation overload places the most demand on cumulative BESS power and energy requirements in 2045 and in 2050 than does avoidance of overloads in the MV or LV networks. The slightly greater BESS power capacity requirements in the LV BESS solution pathway occur because the BESS installations do a better job of providing some incidental restraint on the LV network voltage magnitudes than the BESS installations in the MV BESS solution pathway do, which in turn means that more PV curtailment is alleviated in the former than in the latter and thus that the amount of active power that must be absorbed to avoid substation overload is slightly increased.

Table 11 – BESS installation figures for the LV and MV BESS solution pathways in case 1

Year	2025	2030	2035	2040	2045	2050
Number of BESS installations						
LV BESS solution pathway	0 (0)	0 (0)	4 (4)	45 (49)	66 (115)	96 (211)
MV BESS solution pathway	0 (0)	0 (0)	1 (1)	1 (2)	2 (4)	6 (10)
BESS power capacity (MW)						
LV BESS solution pathway	0 (0)	0 (0)	0.4 (0.4)	4.0 (4.5)	6.0 (10.5)	8.9 (19.4)
MV BESS solution pathway	0 (0)	0 (0)	0.7 (0.7)	1.5 (2.2)	4.1 (6.3)	12.0 (18.3)
BESS energy capacity (MWh)						
LV BESS solution pathway	0.0 (0.0)	0.0 (0.0)	2.4 (2.4)	9.0 (11.4)	15.1 (26.5)	32.6 (59.1)
MV BESS solution pathway	0.0 (0.0)	0.0 (0.0)	2.4 (2.4)	5.1 (7.5)	13.9 (21.4)	40.8 (62.2)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

The numbers and capacities of stand-alone STATCOMs added to the network in each year of the study to alleviate voltage magnitude issues in the LV BESS solution pathway in case 2 are shown in **Table 12**.

Table 12 – STATCOM installation figures for the LV BESS solution pathway in case 2

Year	2025	2030	2035	2040	2045	2050
Number of STATCOM installations	0 (0)	3 (3)	5 (8)	8 (16)	23 (39)	17 (56)
Size of STATCOM installations (kVAR)	0.0 (0.0)	101.5 (101.5)	146.0 (247.5)	281.5 (529.0)	859.0 (1388.0)	560.5 (1948.5)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

The volume of new STATCOMs in the LV BESS solution pathway in case 2 peaks in 2045. This occurs because the number of LV feeders on which the maximum acceptable STATCOM capacity of 100 kVAr cannot address voltage issues, resulting in reversion to traditional network upgrade strategies in the LV BESS solution pathway, starts to become significant in 2050. This is also evidenced by the data that was shown earlier in this section in **Table 8**.

7.4 Oversized BESS installations in case 1b

In variational case 1b, the limit on acceptable BESS power capacity per LV feeder to 100 kW was relaxed. BESS installations larger than 100 kW were then applied in all cases where an additional and significant saving in traditional network upgrade costs could be made using BESS capacity. These were all cases where an LV area splitting upgrade requiring expensive MV buried cable buildout would have otherwise been applied, because displacing this cohort of traditional network upgrades achieves the best overall improvement in cost performance. The first year in which LV area splitting upgrades for underground areas appear is 2040. A large cohort of these that have not already been displaced by 100 kW BESS installations does not appear until 2050 however. This is evidenced by the distribution of power capacities for the additional larger BESS sizes that is depicted in Figure 24.

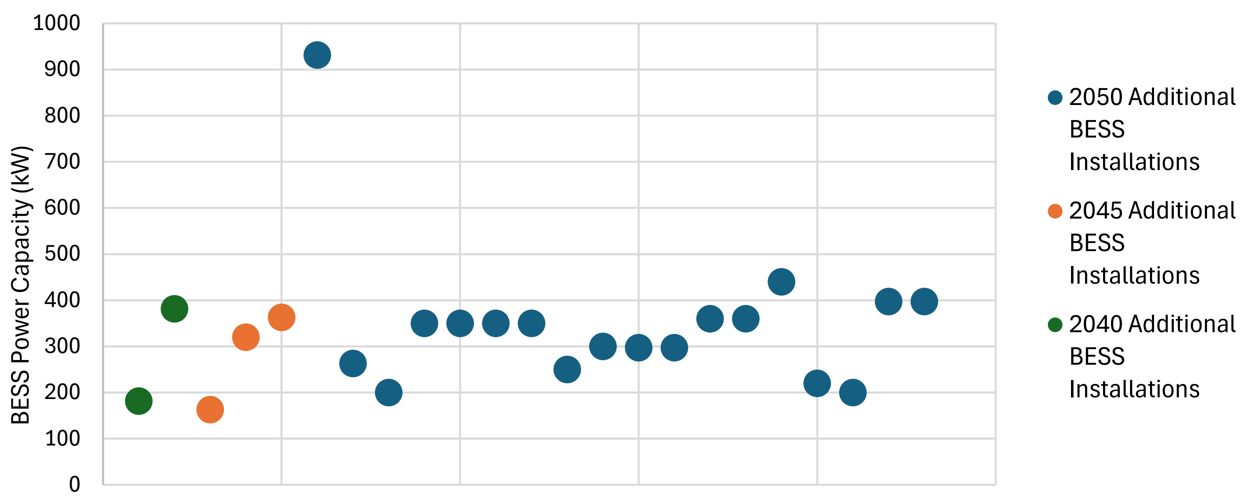

Figure 24 – Distribution of additional BESS installation power capacities applied in variational case 1b

The largest additional BESS installation with a capacity of 931.5 kW is applied to displace one of the traditional network upgrades in 2050. Apart from this outlier, the average of all remaining BESS installations added in case 1b is approximately 306 kW. The ratios of the power ratings of the additional BESS installations to the power ratings of the lowest grade of LV conductor between their point of application and the distribution transformer for their LV area are shown in Figure 25. With the 931.5 kW BESS discounted, the average of this ratio for all of the additional BESS installations is approximately 1.32. Whether or not this indicates that the application of these larger BESS installations would be practically feasible is outside of the scope of this study.

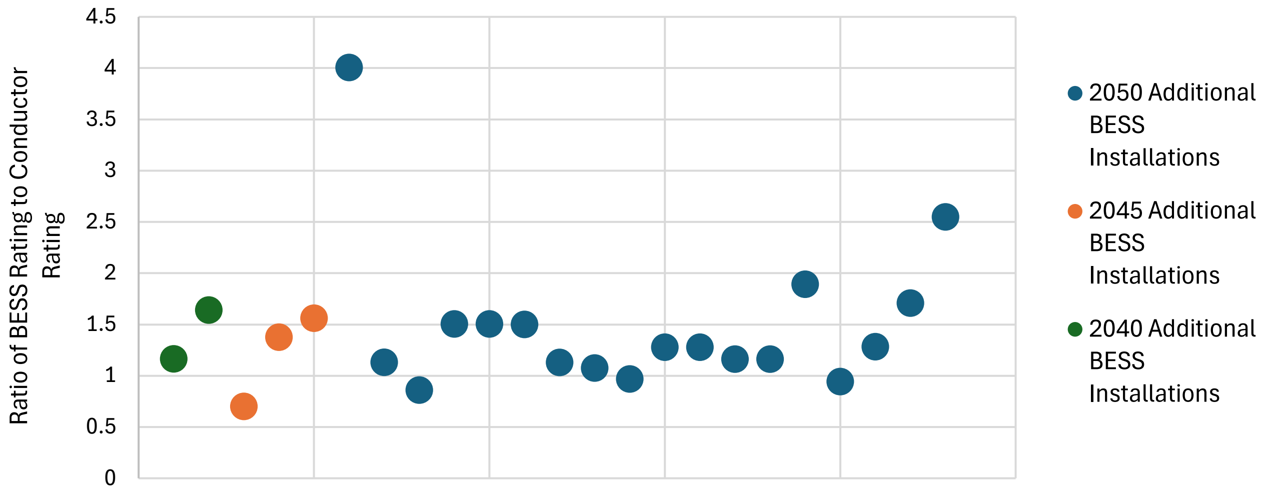

Figure 25 – Ratios of additional BESS installation power capacities to power capacities of their lowest grade upstream LV conductors in variational case 1b

7.5 Zone substation evening overload finding

As detailed in section 4, the overload of the zone substation at midday due to excess solar-derived reverse active power flow was found to occur in 2042 in case 1 if no thermal overload mitigation solutions were applied at all. This upgrade is avoided in both the MV and LV BESS solution pathways by installing sufficient BESS capacity across the network.

Thermal overload of the zone substation modelled for this project was also found to occur at 7pm in the evening in 2049 in case 1 under a BAU scenario. This overload is the result of load growth created by EVs. The finding that this type of overload would occur within the study period was somewhat unexpected as the adoption of solar PV technology by typical Australian household owners began significantly earlier than did the adoption of EV technology. Nevertheless, the midday load trough due to excess solar generation develops and deepens sooner and more rapidly than does the height of the evening load peak created by EV charging. That this is the case is attributable to both the fact that the future growth for rooftop PV is expected to occur sooner and more rapidly than it is for EVs, as well as the inherent greater diversity factor for EV charging when compared to solar PV generation. As a consequence of this, the cumulative installed BESS capacities that are realised by 2050 in both the LV and MV BESS solution pathways would be more than sufficient to remove the evening substation overload by providing active power generation.

On days in which the solar irradiance is high, the charging of the BESS installations needed to provide power generation in the evening adequate to avoid substation overload would occur naturally as a direct consequence of the thermal relief that they provide during the midday period. So that the evening relief could still be provided by the BESS installations on the evenings of days for which the solar irradiance had been low however, the DNSP would need to ensure that the BESS units reach some minimum state of charge in the late afternoon before the evening peak begins. This would be achievable by programming the control systems of the BESS installations so that they automatically charge in the same way throughout the midday period regardless of solar irradiance conditions and PV output. In other words, the BESS installations would simply need to charge based on a timer rather than based on any algorithms that predict or anticipate current PV output.

With reference to the baselined system load curves shown in Figure 6, it is evident that the most difficult type of day on which to implement such a scheme safely would be on a day with low solar irradiance in summer, for which the load reaches approximately 17 – 18 MW throughout much of the midday period. The reactive power flow through the zone substation would be negligible on a day of this type due to the low solar conditions resulting in minimal PV output and hence negligible absorption of reactive power due to volt-var algorithms. Depending on typical EV charging behaviour however, the cumulative load due to EV charging at noon by 2050 would be on the order of 5 – 10 MW. Given that the maximum LV BESS power capacity that would be charging would be ~19.4 MW, it is apparent that the zone substation could also become overloaded throughout the midday period due to the combination of household loads, EV charging and LV or MV BESS charging. It would therefore be necessary to ensure that the control systems managing the charging of the LV and/or MV BESS installations were in some way coordinated with the extent of EV charging across the network, using some form of power flow monitoring and centralized or distributed communication strategy. It might also be beneficial to use forecasts of solar irradiance levels for the next day to dictate whether or not some portion of the BESS installations should charge during the late hours of the evening and early hours of the morning, when negligible other load exists. If the next day were expected to be one with lower solar irradiance, then the need for the BESS installations to be charging throughout the entirety of the midday period to avoid substation overload due to excess solar PV generation would be much less likely to arise.

In any case, it is evident that the flexibility to avoid zone substation overload across all periods of the day should still be possible in any case and regardless of EV charging behaviour and solar irradiance conditions.

7.6 Zone substation rebuild details

As mentioned previously, the effect of the zone substation upgrade on the MV network was represented by assuming that half of the MV feeders had been cutover to substations in neighbouring suburbs in two different sets of simulations and then averaging the results for each of these together in 2045 and 2050. In one set of simulations, the north-western group of five MV feeders was assumed to have been cutover, while in the other set of simulations, the south-eastern group of five MV feeders was assumed to have been cutover. The lengths of these cutover augmentations for the north-western MV feeder cutover projects are detailed in **Table 13**, while the lengths for the south-eastern MV feeder cutover projects are detailed in

Table 14.

Table 13 – MV feeder cutover details for north-western cutover projects

MV feeder name	4A	5A	11A	17A	16A
Old length (km)	4.2	6.3	3.1	2.4	4.8
New length (km)	2.1	3.3	1.4	1.7	1.5
Assumed distance to neighbouring substation for portion of feeder cutover (km)	1.1	1.6	0.7	0.8	0.7

Table 14 – MV feeder cutover details for south-eastern cutover projects

MV feeder name	7A	10A	2A	13A	14A
Old length (km)	3.9	5.8	6.1	4.7	10.1
New length (km)	1.9	2.9	3.1	2.4	4.9
Assumed distance to neighbouring substation for portion of feeder cutover (km)	1.0	1.6	1.7	1.2	2.4

7.7 Case 1 cost analyses

In

Table 15, a cost breakdown for each of the solution pathways in the study for case 1 is shown. Note that the figures correspond to the cashflows needed in each five-year period for new upgrades i.e. they are not cumulative. Note also that costs for BESS installations are inclusive of the cost for an inverter to interface the battery to the network in general.

For the traditional network upgrades solution pathway, the costs for MV feeder splitting upgrades that first appear in 2050 are significant, but the costs for LV area splitting upgrades is the dominant driver of overall costs. For the LV BESS solution pathway, the costs for LV-upgrade-displacing BESS are significantly larger than the reductions in LV area splitting costs that are evident when comparisons to the traditional network upgrades solution pathway are made. The additional costs for non-LV-upgrade displacing BESS are however larger still in this solution pathway. Similarly, in the MV BESS solution pathway, the costs for MV BESS installations are much larger than the costs for LV area splitting.

Table 15 – Cost breakdown for each solution pathway in case 1

	Year	LV area splitting upgrade costs ($M AUD)	MV feeder splitting upgrade costs ($M AUD)	MV feeder re-conductoring upgrade costs ($M AUD)	LV-upgrade-displacing BESS costs ($M AUD)	Non-LV-upgrade-displacing BESS costs ($M AUD)	MV BESS costs ($M AUD)
Traditional network upgrades solution pathway	2035	0.4	0.0	0.6	-	-	-
	2040	2.7	0.0	0.0	-	-	-
	2045	4.4	0.0	0.7	-	-	-
	2050	9.6	3.9	1.5	-	-	-
LV BESS solution pathway	2035	0.2	-	-	0.8	0.0	-
	2040	1.4	-	-	5.0	5.4	-
	2045	2.9	-	-	6.3	7.5	-
	2050	7.3	-	-	8.5	17.3	-
MV BESS solution pathway	2035	0.4	-	-	-	-	2.4
	2040	2.7	-	-	-	-	4.5
	2045	4.4	-	-	-	-	11.7
	2050	9.6	-	-	-	-	32.1

The cost curves calculated for case 1 are shown in Figure 26. Additional curves indicating the variation in overall costs for the traditional network upgrades solution pathway given the ±30% variation that is applicable to the cost for the zone substation upgrade have also been included.

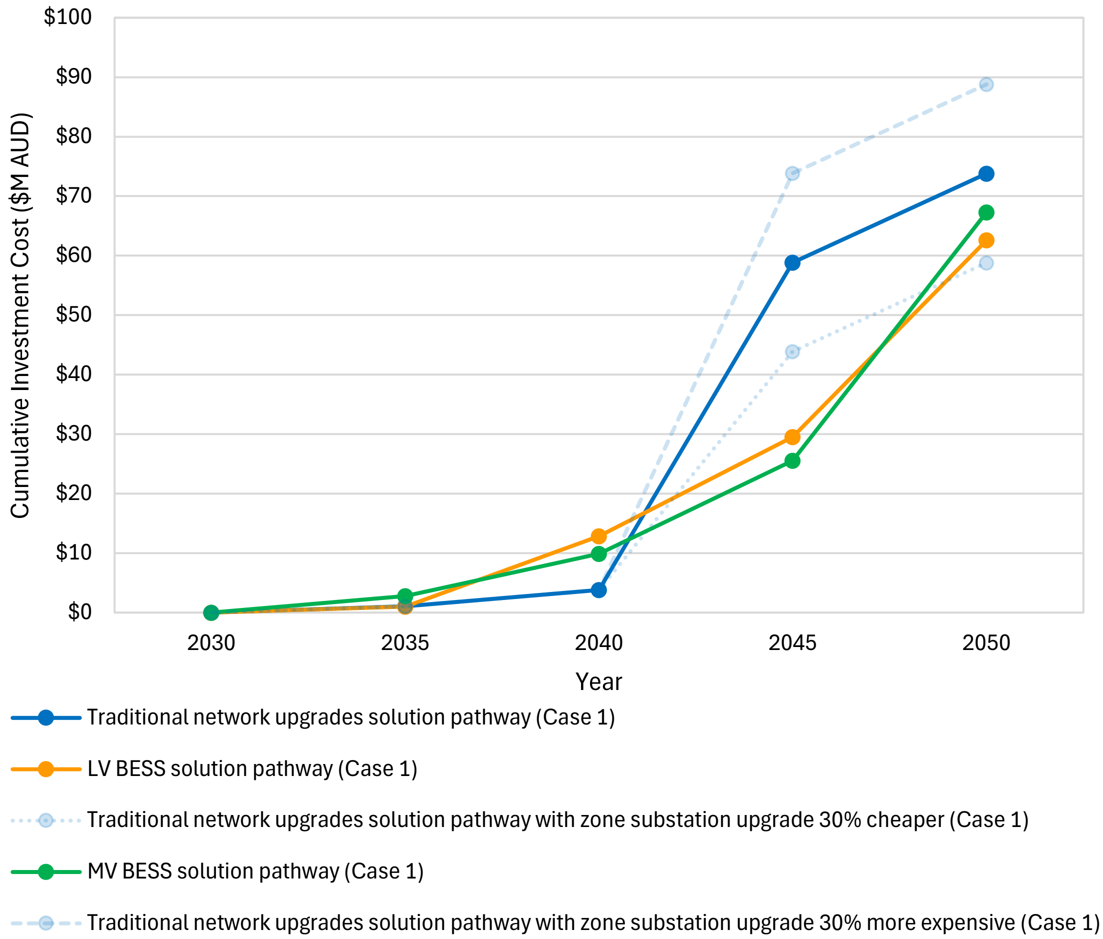

Figure 26 – Cost curves for case 1

The results shown in Figure 26 have several salient features. Firstly, it is clear that the costs for the MV and LV BESS solution pathways are higher than those for the traditional network upgrades solution pathway in the early years of the study. Once the zone substation upgrade occurs in 2042 in the latter solution pathway however, the MV and LV BESS solution pathways become significantly cheaper than traditional network upgrades in 2045. By the year 2050, the MV and LV BESS solution pathway costs increase to values almost as high as the traditional network upgrades costs, but just below it. If the uncertainty in the cost of the zone substation upgrade in the traditional network upgrades solution pathway is taken into account, it is evident that the final cost for this solution pathway in 2050 could come in at just below the final costs for the MV and LV BESS solution pathways or significantly above it.

Between 2045 and 2050, the costs of the MV and LV BESS solution pathways increase by amounts that are significantly larger than the extent to which they increase between 2040 and 2045 or in other previous time periods. For the traditional network upgrades cost curve also, the increase in cost from 2045 to 2050 is larger than in all previous time periods if the zone substation upgrade cost is discounted. This increase in year on year network upgrade costs in 2050 occurs because of the sudden emergence of much larger numbers of thermal overloads in both the MV and LV networks. The fact that the slope of the MV and LV BESS cost curves is larger than the slope of the cost curve for traditional network upgrades in all time periods other than the one in which the zone substation upgrade occurs is a reflection of the fact that the former type of upgrades are, on average at least, significantly more expensive. This is true despite the fact that the gradual reductions in the costs of battery technology that are expected to occur in future have been accounted for.

The only reason that the MV and LV BESS solution pathways incur smaller overall costs than the traditional network upgrades solution pathway even out to 2050 is that BESS installations can displace multiple traditional network upgrade costs simultaneously. Specifically; the active power absorbed by the MV and LV BESS installations displaces both the zone substation upgrade costs and the MV network upgrade costs that otherwise have to be incurred in the traditional network upgrades solution pathway. The LV BESS solution pathway has the additional advantage that it can also displace many of the traditional network augmentation costs for LV area upgrades as well. This advantage only bears out a decrease in overall cost of the LV BESS solution pathway relative to the MV BESS solution pathway in 2050 however.

The final slopes for all three curves would also seem to indicate that the total costs for the BESS solution pathways would eventually overtake the total cost for traditional network upgrades some time after 2050. When this would be likely to occur however is unclear; given the ±30% variation in the cost of the zone substation upgrade, this could occur immediately in 2050 or much later. Extrapolation of the cost curves into the future would not provide a dependable prediction however, because the rate at which additional thermal constraints become binding throughout the network exhibits significant nonlinearity due to the hard-limit nature of thermal rating constraints. The number of both MV and LV network upgrades that must occur in 2050 is significantly larger than in any previous time period. It is difficult to infer how many more of these would be required if the penetration of PV generation were to increase even further.

7.8 Variation case 1a cost analyses

The cost curves calculated for variation case 1a are shown in Figure 27. The curves for case 1 are also shown in dulled colours for comparison.

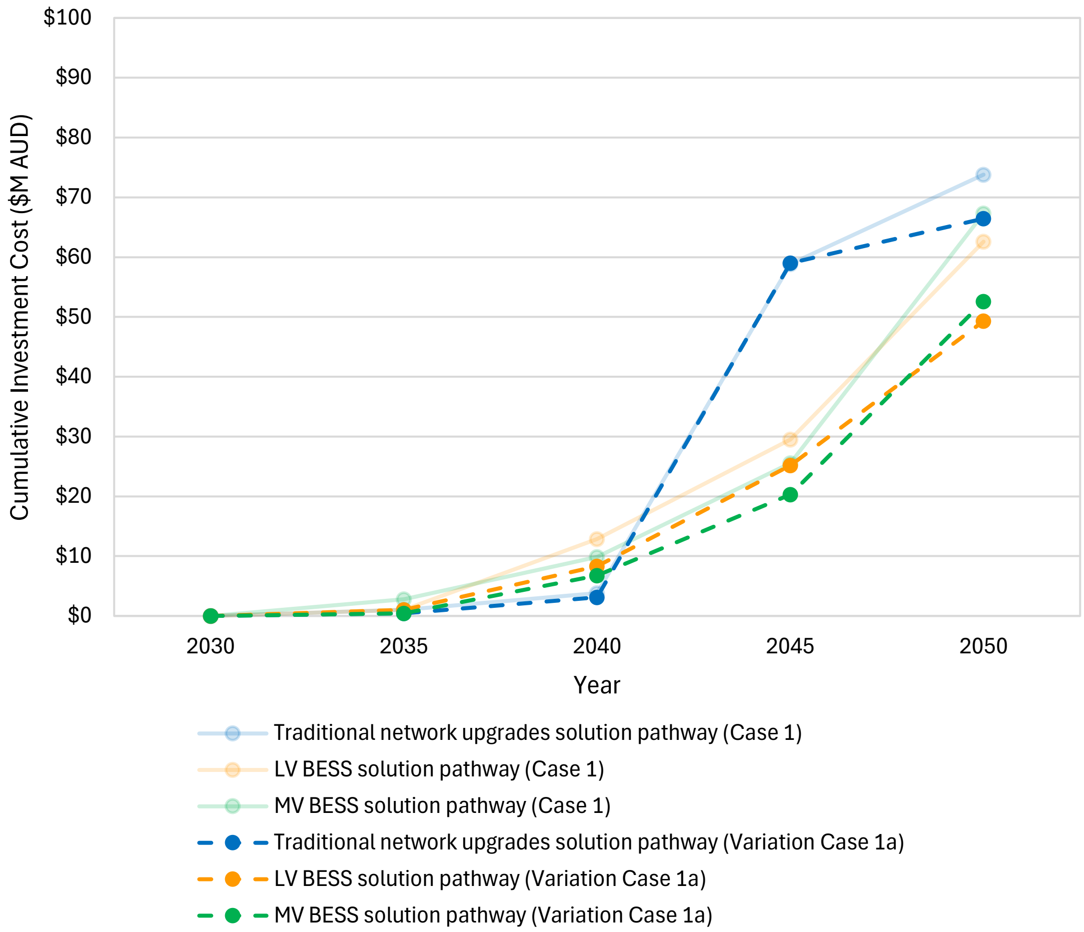

Figure 27 – Cost curves for variation case 1a and case 1

The addition of BTM BESS installations and more typical daytime EV charging has resulted in a reduction in the rate of emergence of thermal constraints across the MV and LV networks, and hence a reduction in the cost curves for all three solution pathways. The extent of that reduction by 2050 is approximately $7.4M for the traditional network upgrades solution pathway, $13.3M for the LV BESS solution pathway and $14.7M for the MV BESS solution pathway. The reason that the BESS solution pathways enjoy a bigger cost reduction in this variation case is that the costs for traditional network upgrades are more or less determined solely by the size of the peak thermal loading factors that they must relieve, whereas the costs for BESS installations are determined by both the size of the peak thermal loading factors as well as the volume of their time-integrals throughout the day. To put this in other words; the BESS costs are driven by both their power and energy requirements, whereas the costs for traditional network upgrades are driven only by power requirements. Since both the power and energy of the thermal loading violations occurring throughout the MV and LV networks are reduced by the increased load that is provided throughout the middle of the day by the BTM BESS installations and additional EV charging, the LV and MV BESS upgrade costs become cheaper in response to reductions in residual peak PV injection at a rate that is faster than linear, whereas the traditional network upgrade costs become cheaper at a rate that is quasi-linear. Nevertheless, the indication that BESS costs would eventually exceed traditional network upgrade costs sometime after 2050 if growth in PV generation continues is still present in this variation case, although the time at which this exceedance would occur seems to be further in the future than in case 1.

It is noted here that the BTM BESS installations that were introduced into the model for the simulations for variation case 1a represent the sizing of the typical installation based on the power and energy capacity growth projections shown in the 2024 ISP. As such, on a clear-sky day in spring they commence charging around 6am and have finished charging by around 9am, as it was assumed that their charging behaviour would be controlled with the simple objective of minimizing self-consumption of each individual household. This aligns with previous results found in studies such as [10]. A direct consequence of this is that the inclusion BTM BESS installations has no effect on the peak power loading on equipment across the network at noon or the power capacity required for displacing the zone substation upgrade in general. It only affects the amount of additional LV or MV BESS installation requirements in 2050 by way of the reducing the cumulative amount of energy that these installations need to be able to store.

7.9 Variation case 1b cost analyses

The additional cost curve for the LV BESS solution pathway under variation case 1b is shown in Figure 28. The cost curves for case 1 are also shown for comparison.

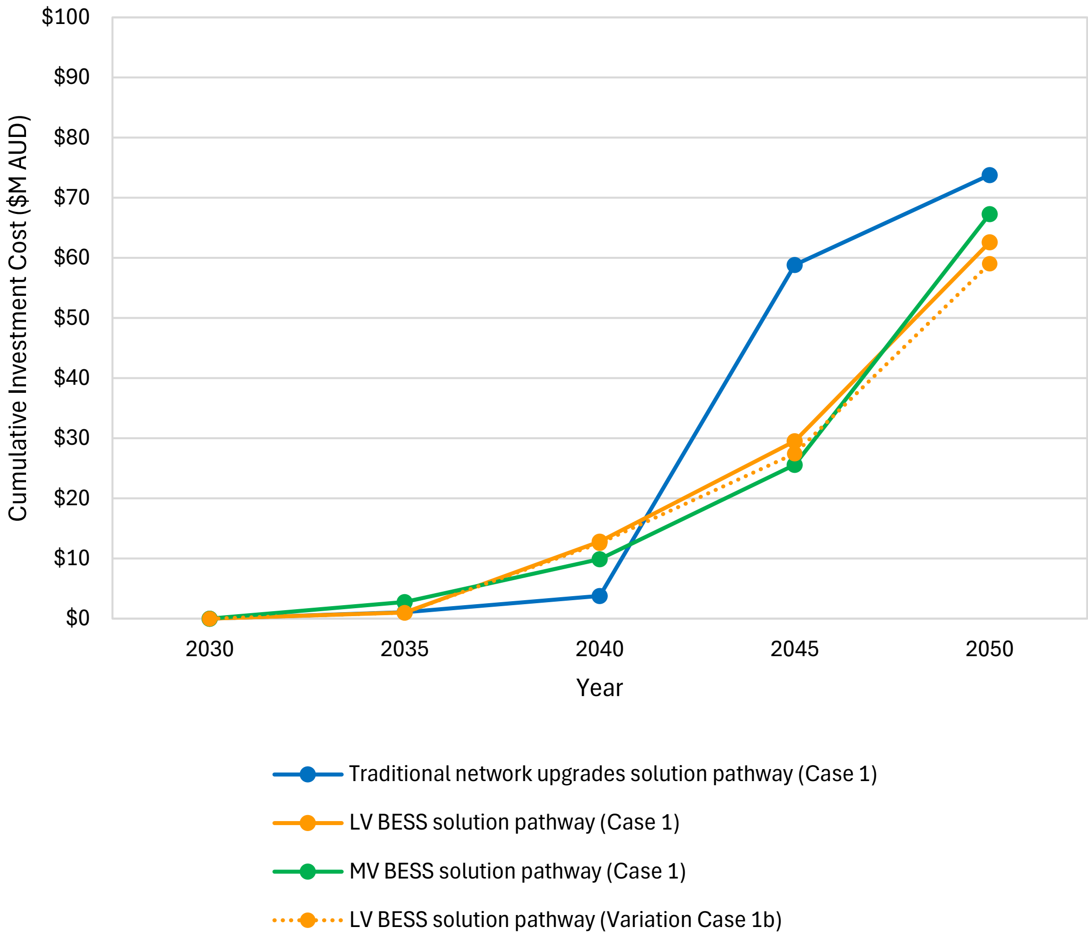

Figure 28 – Cost curves for variation case 1b and case 1

The effect of applying additional LV BESS installations in cumulative capacities greater than 100kW on some of the LV feeders in the network so that further traditional network upgrades can be displaced has been to reduce the overall cost of the LV BESS solution pathway by approximately $3.5M by 2050. Most of this reduction in cost occurs in 2045 and 2050 as the majority of the LV area splitting upgrades for underground areas, which are more expensive in general, do not occur until 2045 and 2050, as indicated by Figure 20.

The LV BESS solution pathway has the potential to displace traditional network upgrades in the LV areas of the network that MV BESS solution pathway does not have. This variation case demonstrates that the size of this benefit could be increased if the limitations on how much BESS power capacity can be installed on any one LV feeder are more lenient. The practical feasibility and safety that would accompany such leniency is however an open question; one that goes beyond the scope of this project.

7.10 Case 2 cost analyses

In **Table 16**, a cashflow breakdown for each of the solution pathways in the study for case 2 is shown. Note that the figures correspond to the cashflows needed in each five-year period for new upgrades i.e. they are not cumulative. Note also that costs for BESS installations are inclusive of the cost for a STATCOM to interface the battery to the network in general, while the costs for LV STATCOMs shown in **Table 16** are for stand-alone STATCOM devices intended solely to alleviate voltage magnitude issues.

Making comparison to **Table 15** which gave the cost breakdown for case 1, it is apparent that the additional costs for STATCOMs in case 2 are relatively small, while the costs for LV area splitting upgrades have increased slightly in all three solution pathways. Additional costs for LV re-conductoring created by the need to alleviate voltage magnitude issues are also relatively small.

Table 16 – Cost breakdown for each solution pathway in case 2

	Year	LV re-conductoring costs ($M AUD)	LV area splitting upgrade costs ($M AUD)	MV splitting upgrade costs ($M AUD)	MV feeder re-conductoring upgrade costs ($M AUD)	LV STATCOM costs ($M AUD)	LV BESS costs ($M AUD)	MV BESS costs ($M AUD)
Traditional network upgrades solution pathway	2030	0.2	0.3	0.0	0.0	-	-	-
	2035	0.0	0.8	0.0	0.6	-	-	-
	2040	0.0	3.4	0.0	0.0	-	-	-
	2045	0.1	5.9	0.0	0.7	-	-	-
	2050	0.3	11.4	3.9	1.5	-	-	-
LV BESS solution pathway	2030	0.0	0.0	-	-	0.1	0.0	-
	2035	0.0	0.4	-	-	0.1	0.8	-
	2040	0.1	1.4	-	-	0.2	10.2	-
	2045	0.1	3.4	-	-	0.7	13.6	-
	2050	0.2	7.6	-	-	0.5	24.9	-
MV BESS solution pathway	2030	0.2	0.3	-	-	-	-	0.0
	2035	0.0	0.8	-	-	-	-	2.4
	2040	0.0	3.4	-	-	-	-	4.5

	2045	0.1	5.9	-	-	-	-	11.7
	2050	0.3	11.4	-	-	-	-	30.5

The cost curves for all three solution pathways in case 2 are shown in Figure 29. The cost curves for case 1 are also shown for comparison.

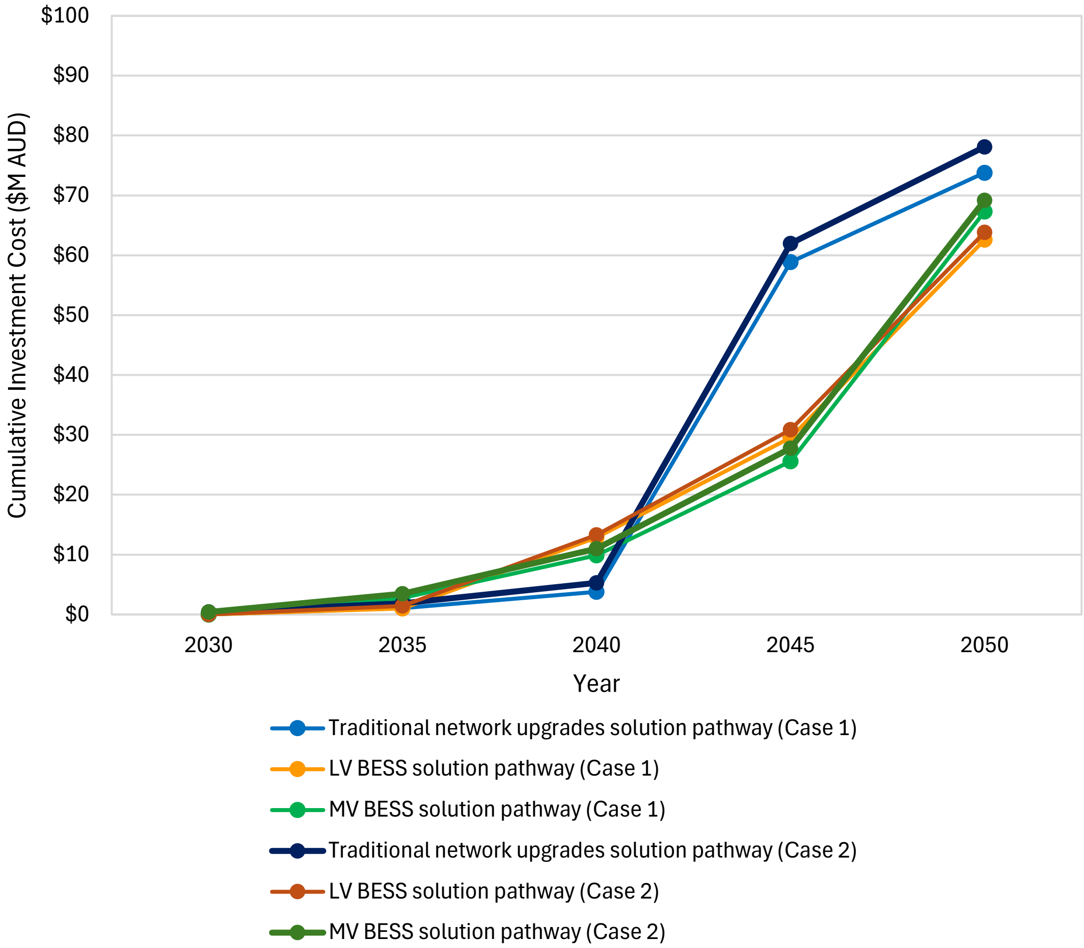

Figure 29 – Cost curves for case 2 and case 1

The findings for this case indicate that the additional costs needed to rectify the additional constraint of LV network voltage magnitudes would be larger in the MV BESS and traditional network upgrade solution pathways than they would be in the LV BESS solution pathway. Specifically, the final costs for the traditional network upgrade solution pathway has increased by approximately $4.3M, while the final costs for the LV and MV BESS upgrade solution pathways have increased by only $1.2M and $1.9M respectively, which is less than half as large. The reason for this is that LV STATCOMs provide a much cheaper solution to LV network voltage magnitude violation issues than traditional network upgrades do. This is starkly contrasted with the situation for thermal constraints; BESS installations are, on average, significantly more expensive than traditional network augmentation strategies when it comes to dealing with these on an individual basis and when only considering the affected area.

Since STATCOMs absorb reactive power when network voltages are too high, their inclusion in case 2 results in the cumulative reactive power flow through the zone substation dropping from approximately 13.6 MVAR to approximately 11.8 MVAR. The reverse active power flow on the other hand increases in magnitude from 37.7 MW to 38.1 MW, due to the reduction in curtailment that is realised by the STATCOMs. Overall, the peak noontime flow through the zone substation falls slightly from approximately 40.1 MVA to approximately 39.9 MVA. It is thus clear that the additional reactive power injected by the STATCOMs does not add any additional risk of zone substation thermal overload.

7.11 Case 3 cost analyses

The cost curves for all three solution pathways in case 3 are shown in Figure 30. The cost curves for case 1 are also shown for comparison.

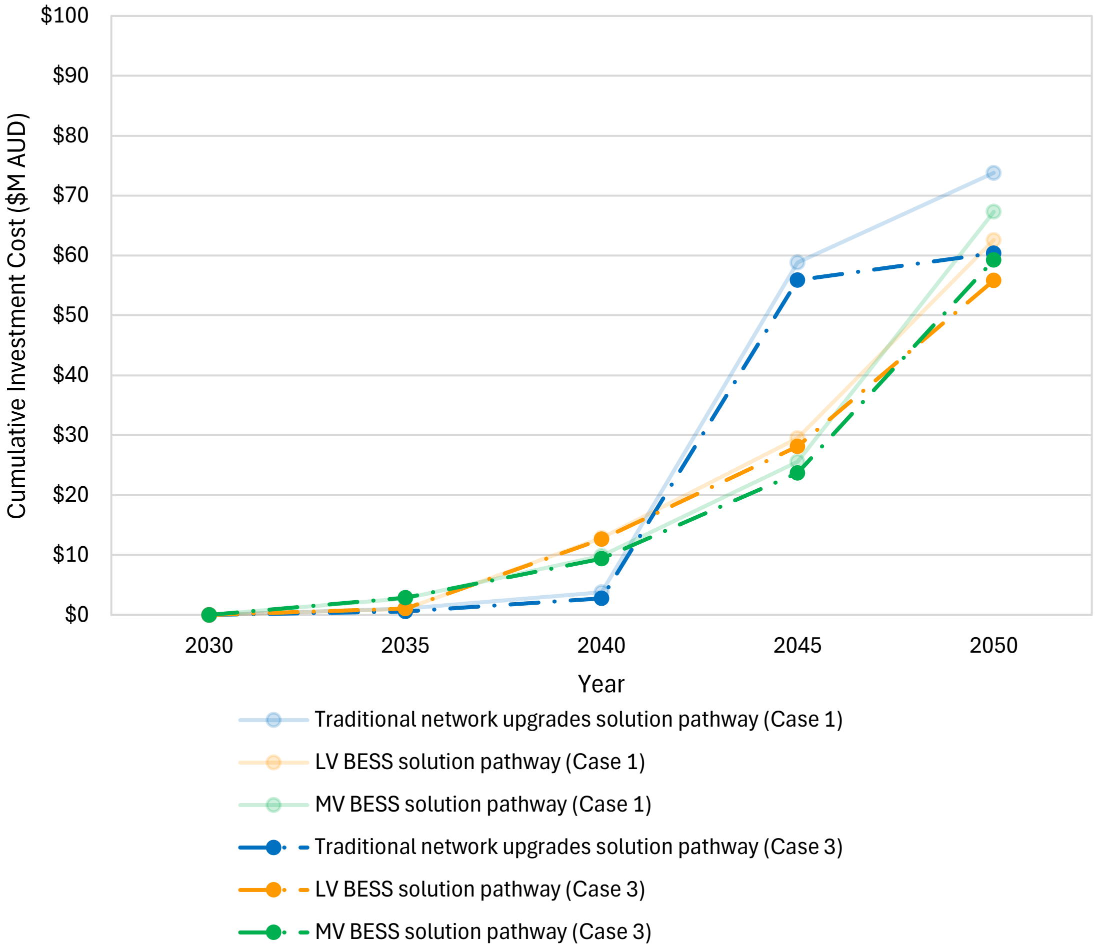

Figure 30 – Cost curves for case 3 and case 1

The cost curves for this case indicate that all three solution pathways would tend towards being cheaper if the zone substation area being relieved consisted entirely of OHL at both the MV and LV levels of the network. The extent to which traditional network upgrades would become cheaper is however significantly larger. Specifically, the cost of the traditional network upgrades solution pathway by 2050 has decreased by approximately $13.4M, while the costs for the MV and LV BESS solution pathways in 2050 have decreased by only $8.0M and $6.7M respectively.

The traditional network upgrades solution pathway incurs a larger saving in this case because the instance of it realised in case 1 involved large numbers of expensive upgrades to both MV and LV buried cables. In the MV BESS solution pathway on the other hand, the MV buried cable upgrades had already been displaced in case 1 by the use of MV BESS capacity also serving the purpose of avoiding zone substation overload. In the LV BESS solution pathway also, displacement of expensive buried cable upgrades at both the MV and LV levels using BESS capacity had already occurred in case 1.

The results for this case imply that the business case for avoiding zone substation overload using MV or LV BESS capacity rather than traditional network upgrades is significantly smaller if the area consists entirely of OHL and that that business case would be more likely to disappear entirely in the years after 2050.

7.12 Case 4 overall cost curves

The cost curves for all three solution pathways in case 4 are shown in Figure 31. The cost curves for case 1 are also shown for comparison.

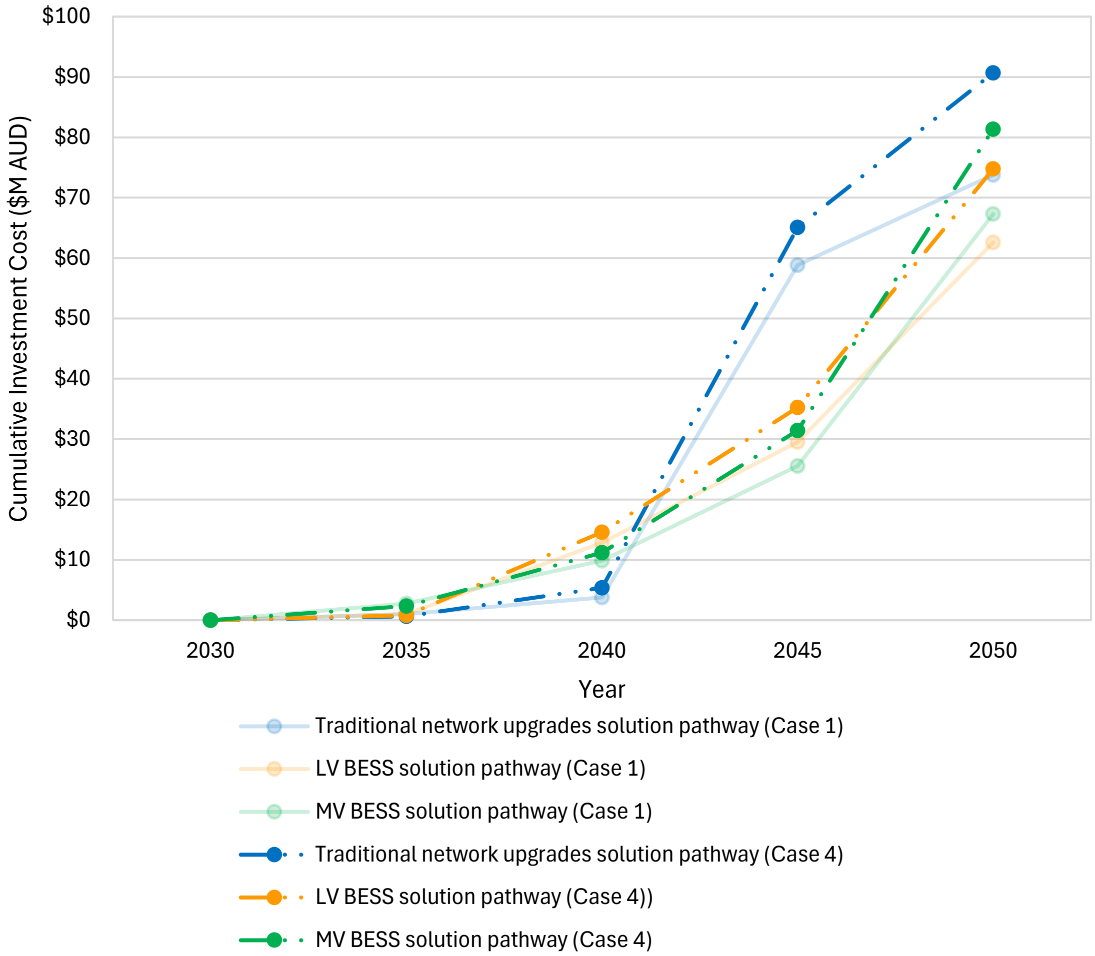

Figure 31 – Cost curves for case 4 and case 1

The cost curves for this case indicate that all three solution pathways would tend towards being more expensive if the zone substation area being relieved consisted entirely of buried cables at both the MV and LV levels of the network. The extent to which traditional network upgrades would become more expensive is however larger. Specifically, the final cost in 2050 would be inflated by approximately $12.2M in the LV BESS solution pathway, $14.1M in the MV BESS solution pathway and $16.9M in the traditional network upgrades solution pathway.

The costs for the MV and LV BESS solution pathways are inflated by less in this case because the instances of these realised in case 1 have displaced all of the traditional upgrades to MV lines using BESS capacity and thus would not suffer inflation of this component of the costs if they were to consist entirely of buried cable upgrades. Furthermore, in the LV BESS solution pathway, many of the traditional LV area upgrades have been displaced already as well, which means that this solution pathway would stand to suffer less inflation of these costs if all of these upgrades had to be performed on underground LV areas.

The results for this case indicate rapidly accelerating costs for all three solution pathways in the period from 2045 to 2050. The accelerated pace of the traditional network upgrades cost curve in particular indicates that the point in time at which the costs of the LV BESS solution pathway would surpass it would be further in the future, if it were to occur at all. The saving incurred by using LV BESS upgrades rather than MV BESS upgrades in this case is also larger as the size of the benefit of being able to displace traditional LV area upgrades is larger.

7.13 Cost curve overtaking years estimated using extrapolation

Extrapolations of the costs of the three solution pathways beyond 2050 using the slopes that they exhibited in the 2045 – 2050 period were used to estimate the year at which the costs of the MV and LV BESS solution pathways would each be expected to overtake those of the traditional network upgrades solution pathway. It is important to caution however that the upgrade costs modelled in this study are highly nonlinear in nature, especially towards the latter years of the study. The extrapolation-derived overtaking years shown here should therefore not be assumed to be accurate. They have merely been calculated and shown here to provide insight into the sensitivities of the cost curves to specific variations in input assumptions.

Table 17 – Year in which the LV and MV BESS solution pathway costs would be expected to overtake the traditional network upgrades solution pathway costs given linear extrapolation

	Year in which traditional network upgrades solution pathway costs would be overtaken by BESS solution pathway costs	
	LV BESS solution pathway	MV BESS solution pathway
Case 1 with BESS costs reduced by 20%	2056	2053
Case 1	2054	2052
Case 1 with BESS costs increased by 20%	2051	2050
Variation Case 1a	2056	2053
Variation Case 1b	2055	2052
Case 2	2055	2052
Case 3	2051	2051
Case 4	2056	2052

The year in which the BESS solution pathway costs would be expected to overtake the traditional network upgrades solution pathway costs is later for the LV BESS solution pathway than it is for the MV BESS solution pathway in all cases studied. The fact that this is the case indicates that it is reasonable to expect that the LV BESS strategy will undercut traditional network upgrade costs for a longer period than an equivalent MV BESS strategy would in general.

Additionally, the overtaking years for each of the BESS solution pathways have been estimated for a variation on case 1 in which the costs for BESS technology are varied by ±20%. This produces more variation in the overtaking year for the LV BESS solution pathway than it does for the MV BESS solution pathway, which is attributable to the fact that the latter solution pathway relies less heavily on BESS installations as thermal overloads at the LV level of the network are addressed with traditional network upgrade solutions. It should be noted that assuming that long-term future BESS costs are 20% higher is highly pessimistic; the fact that the LV BESS overtaking year only recedes by two years as a result of this demonstrates significant robustness of the costings for this solution pathway that have been performed in this study. In other words, this result demonstrates that the cost outcomes for the LV BESS solution pathway identified in this study are not merely a product of overly optimistic assumptions in terms of long-term reductions in costs for the BESS technology.

7.14 NPV analyses

The net present value of the total costs for each of the solution pathways in this study in 2025 were calculated using an assumed annual rate of return for power system assets of 3%. The NPV figures are shown in **Table 18**.

Table 18 – 2025 NPV calculations for each of the solution pathways and cases studied

	Traditional network upgrades solution pathway NPV ($M AUD)	LV BESS solution pathway NPV ($M AUD)	MV BESS solution pathway NPV ($M AUD)
Case 1 with BESS costs reduced by 20%	41.8	29.7	32.3
Case 1	41.9	33.4	35.2
Case 1 with BESS costs increased by 20%	41.8	37.1	39.9
Variation Case 1a	36.5	26.3	27.3
Variation Case 1b	41.9	31.5	35.2
Case 2	44.4	34.2	36.5
Case 3	35.1	30.1	31.2
Case 4	50.5	39.8	42.5

In all of the cases studied, the NPV is lowest for the LV BESS solution pathway and highest for the traditional network upgrades solution pathway. This is the consequence of the fact that the largest costs in the BESS solution pathways occur later in the study period than for traditional network upgrades. It should be noted however that the NPV figures do not capture the effect of future costs beyond 2050 that would be incurred under all three solution pathways unless the growth in uptake of new PV and EVs plateaus.

7.15 Improvements to additional network performance metrics

Apart from the targeted reductions in thermal and voltage magnitude violations, additional network performance parameters are also improved in each of the three solution pathways. The first of these, which are presented in **Table 19** are the active and reactive power losses across the network. Four additional metrics are presented in **Table 20**; the total amount of solar PV curtailment, the proportion of LV areas exhibiting overvoltages, the proportion of LV buses exhibiting overvoltage and the proportion of LV areas exhibiting thermal overload on at least one of their LV conductors. Note that the last of these is not zero in general because the assumption was made in case 1 that the DNSP would not rectify thermal overloads on LV conductors in a given area unless they were also rectifying overload of the transformer for that area at the same time.

All of these metrics are improved from their BAU values by the three solution pathways. Notably however, the extent of their improvements is, in general, larger in the MV BESS solution pathway than they are in the traditional network upgrades solution pathway and larger still in the LV BESS solution pathway. This indicates that the BESS solution pathways both generate additional forms of value for the operation of the network that are not easily quantifiable in financial terms, but which nevertheless serve as additional arguments for their merit.

Table 19 – Total network active and reactive power losses in BAU as well as in each of the three solution pathways in case 1 at noon in spring under high solar conditions

Active Power Losses (kW)						
LV BESS solution pathway	250.4	552.3	1018.9	1352.7	1768.7	2135.7
MV BESS solution pathway	250.4	552.3	991.4	1437.6	1983.8	2481.7
Traditional network upgrades solution pathway	250.4	552.3	1020.4	1532.2	2043.1	2636.4
BAU	250.4	552.3	1036.0	1627.3	2488.6	3801.2
Reactive Power Losses (kW)						
LV BESS solution pathway	-993.6	-494.9	268.8	744.7	1334.4	1734.5
MV BESS solution pathway	-993.6	-494.9	248.6	927.8	1787.8	2511.8
Traditional network upgrades solution pathway	-993.6	-494.9	274.0	1005.9	1846.8	2666.7
BAU	-993.6	-494.9	308.6	1290.6	2731.5	4992.2

Table 20 – Total network curtailed solar power generation, percentage of LV buses in overvoltage, percentage of LV areas in overvoltage and percentage of LV areas with residual thermal overloads in BAU as well as in each of the three solution pathways in case 1 at noon in spring under high solar conditions

Curtailment (kW)						
LV BESS solution pathway	86.5	193.2	359.0	511.9	732.9	958.7
MV BESS solution pathway	86.5	193.2	354.3	555.6	816.9	1043.3
Traditional network upgrades solution pathway	86.5	193.2	364.0	587.8	835.0	1110.1
BAU	86.5	193.2	368.6	611.8	970.3	1439.4
Percentage of LV buses in overvoltage on at least one phase (%)						
LV BESS solution pathway	0.7	1.4	2.0	2.3	3.1	4.0
MV BESS solution pathway	0.7	1.4	2.0	3.4	4.3	5.6
Traditional network upgrades solution pathway	0.7	1.4	2.2	4.0	4.7	6.1
BAU	0.7	1.4	2.3	3.8	5.5	8.0
Percentage of LV areas with overvoltage on at least one phase of one LV bus (%)						
LV BESS solution pathway	3.5	5.7	8.3	10.9	13.5	17.5
MV BESS solution pathway	3.5	5.7	6.6	14.4	17.9	21.8
Traditional network upgrades solution pathway	3.5	5.7	8.2	16.2	19.0	23.6
BAU	3.5	5.7	8.7	17.9	21.5	30.3
Percentage of LV areas with thermal overloads on at least one conductor span/run or the transformer (%)						
LV BESS solution pathway	0.0	0.0	0.9	2.2	7.4	12.7
MV BESS solution pathway	0.0	0.0	0.9	2.6	7.9	14.4
Traditional network upgrades solution pathway	0.0	0.0	0.9	2.6	8.5	15.8
BAU	0.0	0.0	2.2	7.0	19.7	34.5

8 Implications

8.1 Broad findings

The results presented for this project indicate that the MV and LV BESS solution pathways can be expected to yield significantly lower overall network upgrade costs than what would be incurred if a path of traditional network upgrades was pursued until at least as late as 2050 and possibly even out to 2060. They also indicate that it is likely that the costs of the former would overtake the costs of the latter at some point beyond 2050. The amount of time it would take for this to occur is dependent on many assumptions, such as the assumption around how much longer the expected growth in rooftop PV will continue. Real-world constraints on the technological improvements in PV panel efficiency and energy density as well as on available roofspace on typical Australian homes would be likely to cause an eventual plateau in the growth of rooftop PV generation capacity, even if such a plateau is not captured by the current AEMO ISP estimates.

The effective growth in excess PV-generated noontime solar active power could also fall short of the ISP predictions at any point throughout the study period for a variety of other reasons that are difficult to foresee at present, such as changes in government subsidies or regulations or changes in the technological development landscape of DER systems. If such a shortfall were to occur prior to 2042, then the traditional network upgrades strategy would become the cheapest option, at least for zone substation areas that are well represented by the one modelled in this study. If the shortfall were not to occur until later on however, then the cost savings incurred by adopting either of the two BESS strategies instead of traditional network upgrades would be substantial. When considered in conjunction with these possibilities, the MV or LV BESS solution pathways can be justified as hedging strategies against having to bear the substantial costs for traditional zone substation upgrades and MV network augmentations.

The LV BESS solution pathway exhibits a minor cumulative cost saving over the MV BESS pathway in 2050 due to the fact that it affords displacement of some of the traditional network upgrades in the LV network. It was also demonstrated that the size of this saving is scaled to some degree by how lenient the limitation on BESS power capacity per LV feeder is permitted to be. The LV BESS solution pathway may also have a practical advantage over the MV BESS solution pathway due to the fact that it permits more flexibility in where the BESS installations can be installed. In other words, the MV BESS solution pathway might be harder to implement than the LV BESS solution pathway in practice due to the difficulty in acquiring the needed physical space for a smaller number of larger installations. In addition to this, depending on the size of MV BESS units that would be utilised, having a smaller number of larger BESS installations may also mean that the outages and failures of BESS units that would occur from time to time would have a larger negative impact on network reliability.

8.2 Uncosted benefits

Both the MV and LV BESS solution pathways provide several different types of additional benefits beyond the targeted thermal overload and voltage limit exceedance rectification policies. Each of these benefits may correspond to some financial value for the NEM and possibly the customers in it as well as the DNSPs and the TNSPs responsible for the networks. It was not possible however to quantify these values in this study. Some of these benefits were discussed at the end of the previous section; namely the fact that average solar inverter curtailment, residual thermal loading factors, residual voltage magnitudes and active and reactive power losses occurring throughout the modelled zone substation area in the midday period in spring under high solar conditions were all lower in the MV BESS solution pathway than in the traditional network upgrades solution pathway and even lower still in the LV BESS solution pathway. All of these benefits would also extend up into the transmission networks connected upstream of the distribution networks, providing uncosted benefits for the TNSPs as well.

The financial value of reducing solar PV curtailment throughout the middle of the day could be quantified using the CECV metric [18]. It was identified in the RACE for 2030 project preceding this one however that the CECV-derived value of alleviated solar curtailment in the middle of high solar days is not high enough to justify future network investments [3]. This stands to economic reason, as the abundance of solar generation throughout the network during high solar days corresponds to a situation of heightened overall supply and lowered overall demand.

Another uncosted benefit of the BESS solution pathways more significant than those previously mentioned exists; that of the effective removal of generation from the NEM as a whole across the middle of days exhibiting high solar irradiance. This benefit would be an important one because, in the future decades investigated in this study, reverse active power flow will be created not just at the modelled zone substation area but also, eventually, at all substations across the wider distribution and transmission networks. If this excess generation is not accompanied by corresponding load growth, which is likely to be the case unless midday EV charging TOU tariffs are highly successful, it will cause widespread voltage and dynamic stability issues for the entirety of the NEM. Indeed, AEMO has already identified that the potential for such stability issues to occur given a variety of N-1 contingencies in the transmission networks of the NEM is already emerging [19]. In this report, the issue is referred to as the problem of maintaining network security given ever-decreasing minimum operational demand in the NEM. The wider system benefits that could be provided by BESS technology would become especially significant if the one of the two BESS solution pathways, or a combination thereof, were utilised in many of the zone substation areas across each of the distribution networks in the NEM.

The extent of these wider system benefits could be highly significant for the future prosperity of the nation and the overall cost of the energy transition away from fossil fuels. Valuations of BESS technologies and projects based only on the immediate benefits that they would provide to the local areas in the networks where they would be installed would be likely to failing to capture much larger benefits that would accrue if such projects were implemented at any significant scale. Such benefits for BESS installations in the distribution networks could include, for example, reduction of the need to augment equipment upstream in the transmission networks, improved frequency stability across the NEM, improved power quality across the NEM, improved voltage magnitude and unbalance compliance across all levels of the networks and additional enablement of hosting capacity i.e. ability to connect and allow the full utilisation of more LV DER, enabling greater production of renewable energy closer to the homes and businesses where it is needed. The scale and extent of these benefits and the evaluation of the wider economic benefits that they would provide fall well beyond the scope of the present study. They would constitute a topic that only the larger, more well-resourced organisations that are responsible for steering the trajectory of the Australian power industry, such as the AEMO and the CSIRO, would be able to carry out.

Solutions to thermal overload and voltage issues caused by excess PV generation that involve BESS installations fundamentally differ from traditional network upgrades in that they actually remove some of the excess generation from the system. The extent of this for the modelled zone substation is depicted in Figure 32, in which the cumulative active power flow on a spring high solar day in 2050 in case 1 for both the BAU scenario and LV BESS solution pathway is shown. New BESS installations would therefore contribute some degree of alleviation to the minimum load conditions that have already been flagged by AEMO as an urgent emerging issue. Traditional network augmentation options on the other hand do not remove the excess generation and would therefore necessitate more use of the less desirable remediation strategies suggested by AEMO in [19] for maintaining network security in the face of falling minimum operational demand. Some of these undesirable remediation strategies include tapping distribution transformers up by a number of taps that is sufficient to ensure that rooftop PV inverters will trip on overvoltage protection and thus always be inactive throughout the middle of high solar days or even load-shedding of MV feeders exhibiting reverse active power flow.

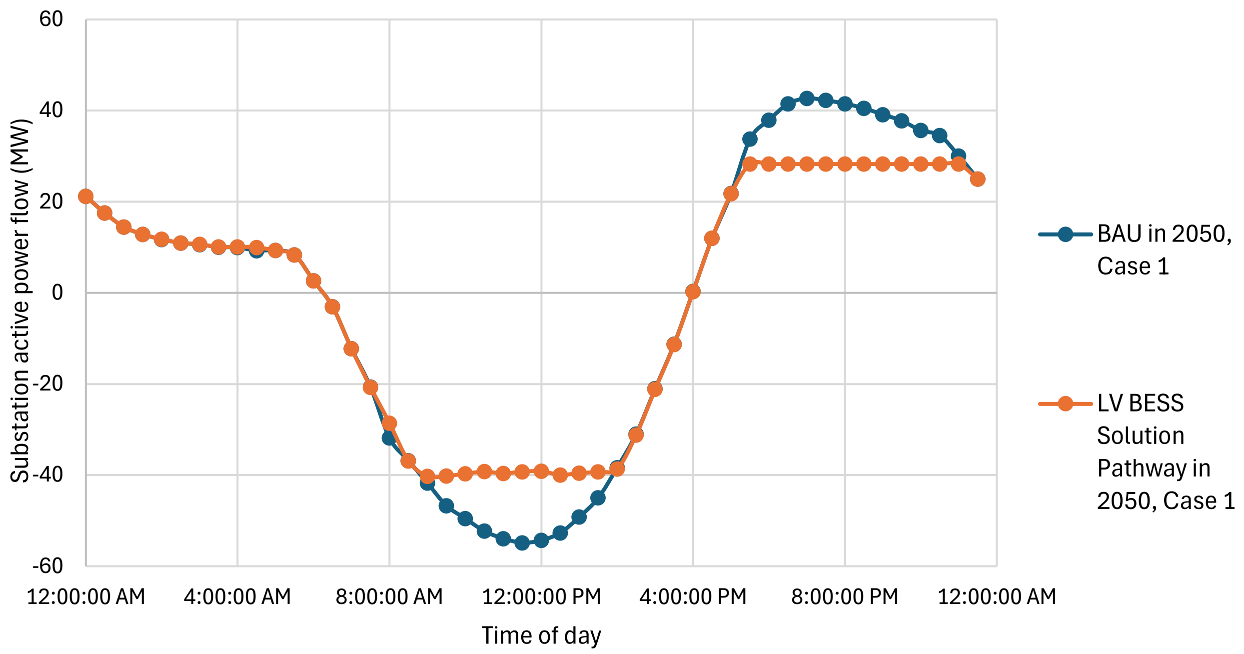

Figure 32 – Zone substation apparent power flow for the typical spring high solar day in 2050 in case 1 in both the BAU scenario and the LV BESS solution pathway

Finally, it should also be mentioned here that the inverters used to interface the BESS installations to the distribution network could also provide other operational benefits during the times of day at which their capacity was not being fully exhausted by battery charging or discharging. Such additional operational benefits, which it was also not possible to estimate the value of in this project, could include harmonic filtering and/or phase voltage imbalance correction, which also naturally realizes efficient voltage magnitude correction. The costs assumed for the inverter installations in this project are reflective of those for sophisticated distribution STATCOM devices which would be capable of providing these additional operational benefits.

8.3 Upgrade cost acceleration factors

In the previous section, linear extrapolation of the cost curves for the three solution pathways investigated in this study was applied to estimate the years beyond 2050 by which the BESS solution pathways might be expected to have surpassed the cumulative costs for the traditional network upgrades solution pathway. It is important to caution that future cost estimation via linear extrapolation is unlikely to produce robust predictions. Furthermore, the predictive power of extrapolation of the cost curves estimated in this study beyond 2050 is rendered even lower by the fact that the underlying upgrade costs in all three of the solution pathways have attributes that exhibit nonlinear dependence on how the network is strained. Put simply; the cost curves for all three solution pathways “accelerate”, in that they become ever steeper in each of the latter time periods simulated, even when the effect of the one-time cost for the zone substation upgrade is factored out. This is the case not only because the number of new thermal and/or voltage issues across the network increases in each year, but also because the underlying upgrade costs exhibit some additional nonlinear dependencies on the severity of the issues being rectified.

For the LV and MV BESS solution pathways, this comes in the form of additional dependencies on the energy requirement to alleviate thermal constraints. While the cost of traditional network upgrades for a given thermal overload scale primarily with peak power requirements alone, LV and MV BESS solution costs scale with both the energy requirement as well as the peak power requirement. Referring to Figure 33, in which the excess solar power flowing through the zone substation in the middle of the day is depicted in an illustrative fashion only; suppose in the first instance that additional BESS installations had to be provided in 2040 to alleviate the exceedance of the substation LARc limit of 42 MVA. The cost of these BESS installations would be proportional not only to the difference between the maximum power value to which region A extends and the value of 42 MVA, but also to the area of that region. This corresponds to the fact that BESS costs scale with both power and energy requirements.

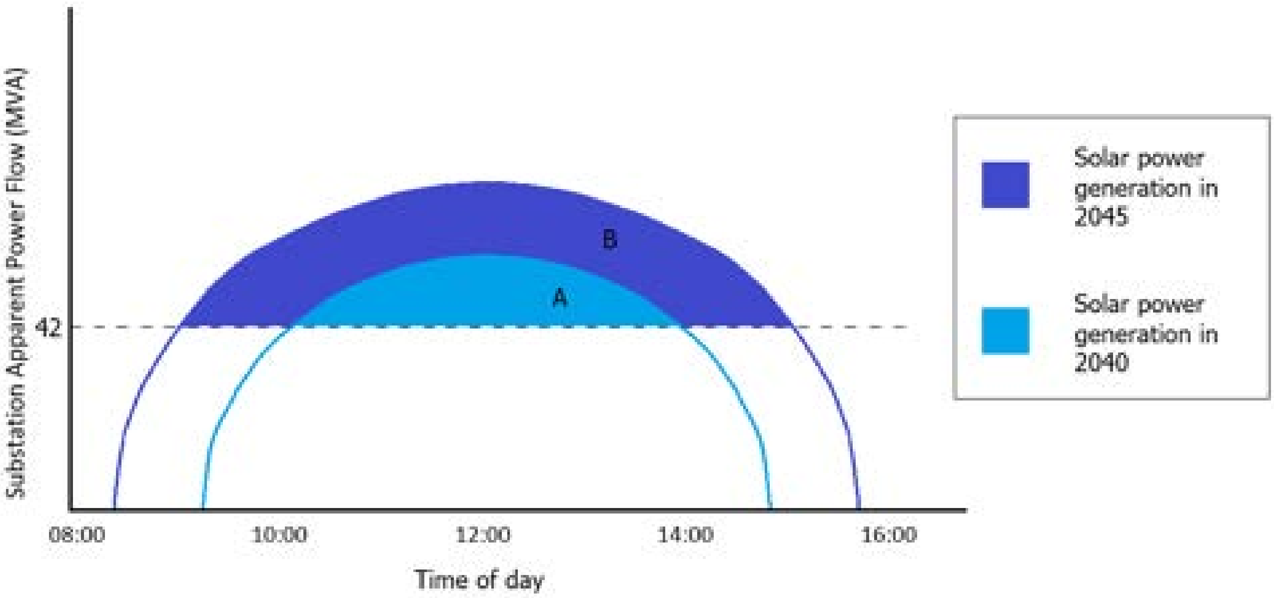

Figure 33 – Conceptual depiction of energy increased energy requirement for alleviating thermal constraints associated with growing excess PV generation

The additional investment in BESS that would then be required to sustain avoidance of the zone substation upgrade out to 2045 would be proportional again to both the difference between the maximum power values of regions B and A and also the area of region B. The difference between the maximum power values of regions B and A is very similar to the difference between the maximum power value of region A and the substation limit of 42 MVA. This corresponds to the fact that when averaged over many thousands of customers, the growth in average PV capacity per household across any two periods of the same number of years will be likely to be similar. Importantly however, the increased temporal width of region B implies that the area of region B is larger than the area of region A, which in turn implies a higher overall investment in BESS energy capacity to maintain the same security of the zone substation area. With reference to the power and energy requirements for the non-LV-upgrade-displacing LV BESS installations that were shown in section 7, this additional dependency is evidenced by the fact that the storage depth used for these installations in 2050 is significantly larger than it is in 2045.

For the traditional network upgrades solution pathway, the additional nonlinear dependence of the upgrade costs on the severity of the issues being rectified exists in the form of saturation of the amount of relief that these solutions can provide. At the LV level of the network, this saturation was found to occur, given the methodology and assumptions used in this study, more or less immediately when the need for rectification measures first emerged in 2035. Specifically, rectification of thermal overloads on LV conductors via re-conductoring was found to be inadequate more or less in general, resulting in LV area splitting being the typical requirement in this solution pathway. The upgrade cost acceleration created by saturation of upgrade options in the traditional network upgrade solution pathway is much more pronounced however in the MV network. At this level of the system, thermal overloads that cannot be alleviated by even the highest feasible grade of buried cable or OHL begin to emerge only in the final year of the study. When they do however, they necessitate the use of MV feeder splitting, which implies extensive additional MV feeder buildout and greatly increased costs.

Due to the nature of these additional nonlinear dependencies, it is very difficult to predict when the costs of the LV BESS solution pathway might overtake those of traditional network upgrades. It is important to note however that the additional cost dependency on energy requirements that the BESS solution pathways suffer an active constraint in all years of this study from 2035 onwards and that this dependency exhibits more or less linear growth with PV penetration when considered in isolation. The dependency of traditional network upgrade costs on overload severity was only captured to a limited extent by this study however. It would be reasonable to expect that it would emerge much more frequently in the years after 2050 as more thermal constraints that cannot be rectified using MV feeder re-conductoring continue to emerge in greater numbers. Given that this is the case, it is conceivable that the traditional network upgrade costs could remain higher than the LV BESS costs for much longer than would be implied by cost curve extrapolation.

8.4 Implications for underground zone substation areas

Case 4 highlights an important consideration that should be made when it comes to the planning of distribution network developments in new suburban areas. It implies significantly higher overall traditional network upgrade costs for zone substation areas constructed entirely using buried cables. On the other hand, buried cables are able to achieve significantly higher reliability performance than overhead lines as they naturally provide more protection from storms, floods, bushfires and other extreme weather events. In March of 2025, almost 250,000 homes have suffered from power outages in south-east Queensland due to the impact of ex-tropical cyclone Alfred [20]. It is not unreasonable to assert that many of these outages would have been less likely to have occurred if the distribution networks across the entirety of south-east Queensland had been constructed entirely with buried cables.

The higher reliability of buried cables may create a strong incentive for network businesses to develop new substation areas entirely underground so that their overall reliability performance can be improved. The cost results for case 4 however indicate that for zone substation areas developed in this way, the eventual costs required to augment the network against thermal overloads emerging from excess rooftop PV would be substantially higher than for similar areas constructed using overhead lines. This is the case both because of the significantly greater cost per unit length associated with installation of buried cables rather than overhead lines as well as the fact that the peak thermal ratings that can be achieved for buried cables are somewhat lower than those that can be achieved with the highest grades of overhead conductor. The latter limitation would result in more expensive LV area splitting upgrades having to occur sooner when thermal overloads begin to emerge.

Zone substation areas being planned now and in future could also be designed with initial thermal margin sufficient to avoid the emergent thermal overloads identified in this study. It is likely however that doing this would realise an expansion of their initial construction costs that would be roughly commensurate with the inflated figures identified for the traditional network upgrades solution pathway in case 4 of this study. Since the improved reliability of buried cables will continue to be desirable, the findings of this study therefore imply that it may be beneficial to plan future distribution network developments with the intention to insert large quantities of BESS installations similar to those explored in this study present from inception.

8.5 Study limitations and future work

Replacement costs for aging batteries as well as reductions in battery costs due to the volumes that they might be purchased in are both costing factors that it was not possible to include in the study. Furthermore, the same input costing assumption was used for LV BESS installations as for MV BESS installations; namely the $383,333 AUD cost for installation of a singular 100 kW BESS with 2.3 hours of storage depth and a 100 kVA inverter for it to interface to the power system through. For the purposes of this study, the same inverter product that would also be sold as a distribution STATCOM was assumed to be used for this purpose in general, though it is noted here that cheaper models of inverters with less functionality could be used. The battery and inverter costs are inclusive of the labour required for a single installation of their corresponding sizes. For the MV BESS solution pathway however, there may be savings that could be incurred relative to the LV BESS solution pathway due to the fact that the MV BESS projects would be much smaller in number and would therefore require less labour than the installation of many smaller LV BESS installations. On the other hand, costs for MV BESS installations could also be higher than for LV BESS installations due to the need to purchase much larger blocks of land as well as the need to install more extensive earthing for MV substation sites. LV BESS sites would only require a few earth rods and a grading ring.

One input assumption that would reduce the extent of costs for all solution pathways in case 2 if it were altered is that which was made around the inability of rooftop solar inverters to provide reactive power support at night when solar irradiance is zero. This could be changed if the requirement to facilitate such functionality were enforced on solar PV manufacturers by new regulations. In reality however, such changes to regulations would be constrained by other political and economic factors. Another input assumption that could alter the outcomes of this study even more significantly and in all cases is the level of compliance with AS4777.2. Recent research indicates poor adherence to AS4777.2 in much of the existing rooftop PV fleet in Australia [14]. Without volt-watt and volt-var support from the emerging PV generation, network issues significantly worse than what was found here would emerge with greater speed.

It is also important to state that the findings of this study are most applicable to urban distribution networks. In the case of rural distribution networks, the greater physical space that would often be available for zone substation upgrades may mean that their implementation would simply involve expansion of the existing site, which would lower their costs substantially. In such situations, the cost performance of the traditional network upgrades solution pathway would often be better than what has been identified in this report and may also be better than the cost performance of the BESS solution pathway.

Also pertinent is the fact that the practical implementation of the MV and LV BESS strategies may run into difficulties due to the space required for installation of the BESS and STATCOM units; it is another limitation of this study that constraints such as these could not be adequately represented. Similarly, the space required to implement MV feeder splitting may also render the traditional network upgrade strategy difficult to implement. These realities may necessitate that some combination of these solution pathways is applied in practice.

If space limitations eventually render continuation of all three solution pathways infeasible, then the only remaining course of action for the DNSP to follow would be to apply aggressive export limits on all solar generation across the network. While this would certainly save the DNSP substantial network investment costs, it would also be likely to induce substantial negative sentiment within the communities of customers that they serve. Furthermore, to avoid overload of the zone substation in the evening peak due to the growth in EVs that will occur while still avoiding the need to pay any network upgrade costs, DNSPs would then also have to apply similar limitations to the rates at which EV owners would be allowed to charge their vehicles in the evening.

An additional advantage of the LV BESS solution pathway that was not explored in this study, but which may be pursued in future work, is that of the saving to LV thermal overload rectification measures that could be afforded by re-balancing of the active and reactive power flows on each of the phases. If four-arm STATCOM devices with a neutral connection are utilised, then it is possible to completely correct the current and voltage imbalances that commonly occur throughout LV networks, provided that the STATCOM has adequate current ratings. In all of the distribution transformer overloads that triggered LV area upgrades in this study, the overload was larger on one phase than on the other two. It is therefore likely that many of these upgrades could have been implemented entirely, or at least partially, with STATCOM capacity used for balancing rather than with traditional network upgrades or LV BESS capacity. As STATCOMs are significantly cheaper than BESS installations, the saving incurred by this strategy would likely be substantial. Its extent however would be somewhat limited by the fact that only a moderately sized portion of the total upgrade costs are associated with LV area upgrades. The sizeable portions attributable to MV network upgrades and the zone substation upgrade would of course be largely unaffected by rebalancing of the LV voltages and currents, although a small benefit due to reductions in network losses created by the rebalancing may be measurable.

8.6 A receding window for commitments to BESS solutions

While real-world space limitations may necessitate that some combination of the three solution pathways studied in this project is applied in practice, it is important to realise that the level of commitment to one or both of the BESS strategies must be large enough to ensure that the cost for the zone substation can be avoided. Furthermore, installation of additional BESS units in volumes commensurate with the growth in PV and EV penetration would need to be continued beyond 2050 to ensure that the zone substation upgrade cost continues to be avoided and isn't merely delayed.

If the BESS installations are not realised quickly enough, or with enough lead time to ensure that the inevitable delays due to unforeseen project difficulties do not make the former an effective reality, then the overload of the zone substation may eventuate in any case. This in turn would force the DNSP's hand; upgrade of the zone substation would have to occur. This would result in the overall cost to avoid network thermal overloads and voltage magnitude exceedances being the worst of both worlds, in that both expensive BESS installation costs and the substantial zone substation upgrade cost would need to be suffered.

The authors of this report are not able undertake the detailed assessment that would be needed to assess whether or not the space limitations applicable in suburban areas would render the numbers of BESS installations or traditional network upgrades suggested as being necessary in this study practically unrealisable. The responsibility to perform such assessments lies with the DNSPs. It is critical that such assessments are carried out as soon as possible; preferably in the 2030s. That way it will be possible to establish which zone substation areas would be most likely to enjoy overall financial benefit from the BESS solution pathways and which wouldn't. For some areas, traditional network upgrades may be substantially cheaper. This would be the case if the zone substation site, or substation sites in neighbouring suburbs, happens to have either substantial physical space spare or thermal capacity in both their transformers or switchgear spare, which could facilitate simpler substation capacity expansion projects that could be realised for a cost substantially lower than $50M AUD. Such a situation is however the exception, rather than the norm, for existing zone substation sites. For typical areas, the results of this study, which indicate that substantial savings in overall upgrade costs would be realised through sufficient BESS capacity, are relevant and applicable.

Another avenue for future work would be to perform a long-term field trial that validates the upstream network benefits identified in this study. Such a trial would entail installation of LV STATCOMS in LV areas on one MV feeder with sufficient capacity to address all of the local voltage issues [21]. Then, following a period of time sufficient time to clearly demonstrate the voltage management benefits of a STATCOM-only solution, batteries could be introduced to demonstrate capacity benefits. The results obtained by such a whole of MV feeder trial could then easily be extrapolated to the whole zone substation.

The delays and teething problems that tend to accompany the roll out of any new network technology mean that for those substations for which the potential for savings exists, the window of time within which to install BESS technology and retain the future enjoyment of avoiding the substation upgrade cost indefinitely will be finite and receding. For those suburban zone substations that are reasonably well represented by the zone substation area represented in this study, it is reasonable to assume that this window would be closed by 2040, or perhaps earlier. If substantial LV and/or MV BESS rollout programs are not effectively progressing without hinderance by the end of the 2030s, then it seems likely that the costs of many zone substation upgrades will have to be borne in any case.

9 Conclusion

In this study, the costs for avoiding thermal overload across a zone substation area in suburban Brisbane due to continued growth in rooftop PV have been estimated for three different solution pathways. Detailed cost comparisons have been made by performing load flow simulations of the different types of LV and MV network upgrades that would need to be made in a traditional network upgrades solution pathway, as well as in MV and LV BESS solution pathways. A load flow model from a previous RACE for 2030 project which includes QDSL based modelling of volt-watt and volt-var support from rooftop PV installations and detailed four-wire coupled models for all of the LV distribution lines was utilised.

In the central case studied, which is referred to as case 1, the zone substation is found to overload in the midday period in 2042 due to excess solar generation if no thermal overload mitigation solutions are implemented. In the traditional network upgrades solution pathway, this problem is dealt with by upgrading the zone substation at the considerable cost of approximately $50M AUD. The results for case 1 indicate that using either MV or LV BESS installations could provide an upgrade strategy that would avoid the need for this costly upgrade to the zone substation as well as a large number of costly MV network upgrades that would have to occur by 2050. Many traditional LV network splitting upgrades could also be displaced by the LV BESS strategy. The zone substation also reaches overload in 2049 at 7pm during the evening peak as a result of EV load growth. In the BESS solution pathways, this overload could also be rectified without a costly zone substation upgrade simply configuring the control systems for the BESS installations so that they spread the evening peak out sufficiently. This spreading would be realised by shifting much of the peak load requirement into the middle of the day on high solar days, or into the late afternoon on low solar days.

The overall cost for both of the BESS solution pathways remains below the total cost for the traditional network upgrades solution pathway by a significant margin in both 2045 and 2050. That this is the case is attributable to the fact that the BESS installations displace multiple traditional network upgrade investments simultaneously by absorbing the excess solar-derived active power flow throughout the middle of the day. They can displace the zone substation upgrade, the traditional upgrades to the MV network and, in the case of the LV BESS solution pathway, many of the traditional LV area upgrades as well. Were it not for this property then the BESS solution pathways would not be feasible at all; the costs for batteries out to 2050 remain significant even with the expected reduction in the cost for this technology accounted for. When looking ahead only to 2050, the BESS solution pathways also exhibit lower NPV values than does the traditional network upgrades solution pathway as they are able to delay upgrade costs further into the future.

The rapidly increasing slope of the BESS cost curves in 2045 and 2050 implies that both of them would be likely overtake the costs for traditional network upgrades at some point beyond 2050 if the growth in PV were to continue at a similar rate. Where this point would be is difficult to estimate however, due both to the nonlinear nature of the thermal constraints appearing in increasing number for each time period modelled and to the large ±30% uncertainty in the size of the zone substation upgrade cost. Furthermore, the underlying upgrade costs in all three solution pathways exhibit additional nonlinear dependencies on the severity of the constraints being resolved. In the BESS solution pathways, the amount of additional cumulative BESS capacity in each upgrade period is proportional to the cumulative daily solar energy generation growth as well as the peak power flows associated with this. In the traditional network upgrades solution pathway, the cost curves also depend on the severity of the MV thermal overloads in a nonlinear fashion because more expensive MV feeder splitting is required once the largest grade of MV buried conductor or OHL has been exceeded. The need for MV feeder splitting only begins to emerge in earnest in 2050 and would be likely to create much larger cost growth in the years beyond 2050. These additional nonlinear dependencies of the cost curves on the severity of the thermal overloads being addressed render the prediction of when the costs of these pathways would overlap even more infeasible.

In any case, the benefit of the BESS solution pathways can be conceived as hedging strategies against the largest parts of the traditional network upgrade costs. A number of uncosted network performance benefits were also shown to be associated with the BESS solution pathways. Significant consideration should also be given to the fact that the pursuing them would provide some assistance towards the much larger-scale problem of network insecurity due to declining midday minimum load values across the NEM. Furthermore, the inverters used to interface the BESS installations to the distribution network could also provide other operational benefits during the times of day at which their capacity was not being fully exhausted by battery charging or discharging. Such additional operational benefits, which it was also not possible to estimate the value of in this project, could include harmonic filtering and/or phase voltage imbalance correction, which also naturally realizes efficient voltage magnitude correction.

Additional cost curves were also estimated for a variety of different cases. In variational case 1a, it was found that including the effect of a TOU tariff intended to move EV charging towards the middle of the day and growth in BTM BESS installations could reduce the costs in all three solution pathways, but that the extent of this reduction is larger for the BESS solution pathways because their costs scale with both the peak power and energy values needed to avoid the thermal overloads, whereas the traditional network upgrades scale only with the peak power requirement. The realism of this variation case is somewhat unclear however, because even if EV TOU tariffs and growth in BTM BESS were to occur to the extent that they were modelled here, the reductions in noontime excess reverse active power flow due to excess PV generation that they create could only be used to justify savings in network upgrade investments if they were to occur day in and day out in a highly dependable fashion. The fact that customers would still be in control of the EVs and BTM BESS installations in general means that the DNSP may not be able to rely on these reductions in power flow. Ultimately, a DNSP is responsible for maintaining network integrity and security on all days of the year, which includes all outcomes of aggregate customer behaviour that are possible.

In variation case 1b, the 100-kW limit on the amount of BESS capacity that could be applied on any one LV feeder in the LV BESS solution pathway was relaxed. This meant that many more of the most expensive traditional network upgrades to LV areas, some of which entail buildout of MV buried cables, could be displaced by LV BESS capacity. This had the effect of reducing the final cost for the LV BESS solution pathway even further. The realism of this variation case is also somewhat unclear, however. This is the case because the larger the BESS power capacity that is permitted to be installed on any given LV feeder, the higher is the risk that the BESS installation itself will thermally overload the feeder if its control system malfunctions in some way and causes it to inject or absorb active power at the wrong time. Quantification of the validity of this variation case is therefore beyond the scope of this study. Nevertheless, the results that it yields indicate that the additional cost savings that the LV BESS solution pathway provide over the MV BESS solution pathway by displacing traditional network upgrades to LV areas can be made larger if installation of larger BESS power capacities is permitted on any given LV feeder.

In case 2, the costs required to rectify voltage magnitude issues were also included for each of the solution pathways. It was found that the costs for the MV BESS and traditional network upgrade solution pathways increased by larger amounts. This is the case because LV area splitting upgrades and re-conductoring of sections of LV OHL and buried cable are both more expensive on average than installation of STATCOMs, which was the solution used in the LV BESS solution pathway.

In cases 3 and 4, alterations to the cost curves for each solution pathway that would occur if the zone substation area modelled were the same size but composed entirely of OHLs or buried cables respectively were estimated. In case 3, the costs for all three solution pathways were significantly reduced, whereas in case 4 the costs for all three solution pathways increased significantly. The extent to which the BESS solution pathways produce savings relative to the traditional network upgrades solution pathway is reduced in case 3. In case 4 on the other hand, the extent to which the LV BESS solution pathway produces savings relative to both of the other solution pathways is larger than it is in case 1. The latter result is particularly relevant to the planning and development of distribution networks for new suburban areas, as the reliability benefits of buried cables make them an attractive option in general.

The years beyond 2050 at which linear extrapolation of the cost curves for the MV and LV BESS solution pathways would overtake the linearly extrapolated cost curve for the traditional network upgrades solution pathway were also estimated for each of the cases studied. While these overtaking years cannot be assumed to be accurate, they indicate that the cumulative costs for the LV BESS solution pathway would be likely to remain below the cumulative costs for the traditional network upgrades solution pathway for longer than the cumulative costs for the MV BESS solution pathway would in general i.e. in all cases studied.

The effect of varying the assumed rate of decline of battery costs by ±20% on the year at which the linearly extrapolated costs for the LV and MV BESS solution pathways would overtake the linearly extrapolated costs for the traditional network upgrades solution pathway in case 1 was also tested. It was found that this variation of the battery input cost assumption moved the LV BESS solution pathway overtaking year around by ±3 years and the MV BESS solution pathway by -1 years when the battery costs were 20% higher and +2 years when the battery costs were 20% lower. The fact that the LV BESS overtaking year is more sensitive to assumed battery costs than the MV BESS overtaking year is attributable to the fact that the latter solution pathway uses more traditional network upgrade solutions and less batteries than the former solution pathway does. The fact that both solution pathways exhibit relatively minor variation in their late-stage cost curves in response to such significant variation of the battery cost assumption indicates that the findings of this study are relatively robust to inaccuracies in future battery cost estimates.

All three of the solution pathways for thermal overloads costed in this project are likely to become constrained by space limitations at some point. It may therefore be necessary to apply a combination of them in practice. The profile of technological solutions needed to future-proof Australian distribution networks should include a mixture of STATCOM and BESS installations as well as traditional network upgrade solutions. While DNSPs may be inclined to enforce fixed limits to the amount of power that customers can generate using their PV installations and the rates at which they can charge their EVs at certain times of the day, the negative sentiment that this would eventually create in the community would necessitate that this strategy would not be a satisfactory indefinite solution. It is therefore advisable that one or both of the BESS strategies are employed at least to the degree that will avoid costly zone substation overloads, so that the combination of strategies employed does not amount to a "worst of both worlds" approach. Analyses more detailed than those which were carried out in this study should be conducted by each of the DNSPs for as many zone substations as possible to identify which zone substations would see long-term financial benefit from commitment to either of the BESS strategies. This commitment would then have to be rigidly adhered to in the substation areas identified, as failure to continue installation of new BESS capacity at a rate commensurate with growth in PV and EV technologies would result in eventually needing to upgrade the zone substation and suffering higher overall costs. Given that rollout of the BESS technologies will be likely to see many practical delays, it is expected that these programs should be initiated as soon as possible, preferably before the end of the current decade.

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Appendix A – Characteristics of the existing network

Table 21 – Data characterising the ten MV feeders in the modelled area

Feeder	Feeder 01	Feeder 02	Feeder 03	Feeder 04	Feeder 05	Feeder 06	Feeder 07	Feeder 08	Feeder 09	Feeder 10
Total backbone length (m)	9029	4197	6254	3908	5808	3061	4848	4170	4804	2110
Total conductor length (m)	17141	6404	14958	8140	12931	9755	10501	10897	11246	2813
Proportion of MV that is underground (%)	87.16	4.5	19.15	33.27	75.33	25.9	20.5	40.8	35.48	41.46
Proportion of MV that is overhead (%)	12.84	95.5	80.85	66.73	24.67	74.1	79.5	59.2	64.52	58.54
Peak load kVA	3025	1124	2595	2269	3259	2596	2603	2125	3560	1640
No. of distribution transformers	39	15	36	27	25	29	25	15	34	14
Transformer installed capacity (kVA)	14938	4085	8371	10285	10603	9220	6755	10295	11370	6900
No. of LV feeders	95	28	54	56	63	63	51	23	78	19
Total LV feeder length (m)	37912	10115	21424	22564	31856	27839	23819	10589	29842	5790
Proportion of LV that is underground (%)	95.19	2.22	38.49	69.17	96.22	26.99	14.19	61.65	50.06	16.84
Proportion of LV that is overhead (%)	4.81	97.78	61.51	30.83	3.78	73.01	85.81	38.35	49.94	83.16

Table 22 – MV overhead conductor types and cumulative installed lengths within the modelled area

MV Overhead Line Type	Cumulative Distance in Model (km)	Proportion of all MV Overhead Line Distance in Model (%)
11 kV O/H - Other	0.103	0.3
HDBC 7/.08_100°C_11kV_A_SEQ	0.071	0.2
Pluto_75°C_11kV_B_SEQ	0.128	0.4
7/.186 AAC_100°C_11kV_A_SEQ	0.187	0.6
HDBC 7/.08_75°C_11kV_A_SEQ	0.210	0.6
Banana_75°C_11kV_B_SEQ	0.359	1.1
Moon_55°C_11kV_A_SEQ	0.473	1.4
Apple_75°C_11kV_B_SEQ	0.473	1.4
Libra_75°C_11kV_A_SEQ	0.847	2.6
Moon_75°C_11kV_A_SEQ	0.879	2.7
11kV120CCT75A	1.135	3.5
Apple_55°C_11kV_A_SEQ	1.218	3.7
Mars_75°C_11kV_A_SEQ	1.301	4.0
Libra_55°C_11kV_A_SEQ	1.384	4.2
Libra_100°C_11kV_A_SEQ	7.551	23.1
Mars_100°C_11kV_A_SEQ	7.976	24.4
Moon_100°C_11kV_A_SEQ	8.372	25.6

Table 23 – MV buried cable types and cumulative installed lengths within the modelled area

MV Buried Cable Type	Cumulative Distance in Model (km)	Proportion of all MV Buried Cable Distance in Model (%)
11kV UG - Other	0.224	0.5
11kVUG185cuPLYHDPDU	0.390	0.9
11kVUG185cuPLYDU	0.502	1.1
11kVUG25cuPLYHDPEDU	0.535	1.2
11kVUG95alXLDB	0.628	1.4
11kVUG300alPLYDU	1.005	2.3
11kVUG240cuPLYDU	1.055	2.4
11kVUG240alXL70DU	1.292	3.0
11kVUG95alXLDU	1.531	3.5
11kVUG240cuXL90DU	2.824	6.5
11kVUG240cuTRPX90DU	3.830	8.8
11kVUG400alTRPX90DU	4.901	11.2
11kVUG240alTRPX90DU	12.218	28.0
11kVUG240alXL90DU	12.755	29.2

Table 24 – LV overhead conductor types and cumulative installed lengths within the modelled area

LV Overhead Line Type	Cumulative Distance in Model (km)	Proportion of all LV Overhead Line Distance in Model (%)
LV - O/H - Other	0.061	0.1
LV - LIBRA	0.548	0.6
LV - BANANA	1.094	1.2
LV - MINK	1.386	1.5
LV - MARS	15.239	16.6
LV - 95 ABC	19.967	21.8
LV - MOON	53.420	58.2

Table 25 – LV buried cable types and cumulative installed lengths within the modelled area

LV Buried Cable Type	Cumulative Distance in Model (km)	Proportion of all LV Buried Cable Distance in Model (%)
LV - UY/G - Other	0.105	0.1
LV - 150 Cu 3C+NS	0.245	0.2
LV - 25 Cu 4C XLPE	0.367	0.3
LV - 300 Al 3.5C	0.479	0.4
LV - 25 Cu 3C+NS PVC	0.496	0.4
LV - 120 Al 3C+NS	0.656	0.5
LV - 240 Cu 4C XLPEPVC	0.764	0.6
LV - 25 Cu 4C PLY-HDPE-PVC	0.878	0.7
LV - 120 Cu 4C XLPEPVC	0.908	0.7
LV - 240 Al 3C+NS	1.506	1.2
LV - 16 Cu 4C PVC	1.553	1.3
LV - 16 Cu 4C XLPE	18.793	15.1
LV - 120 Al 4C XLPEPVC	24.769	19.9
LV - 240 Al 4C XLPEPVC	72.637	58.5

Appendix B – Additional decision trees

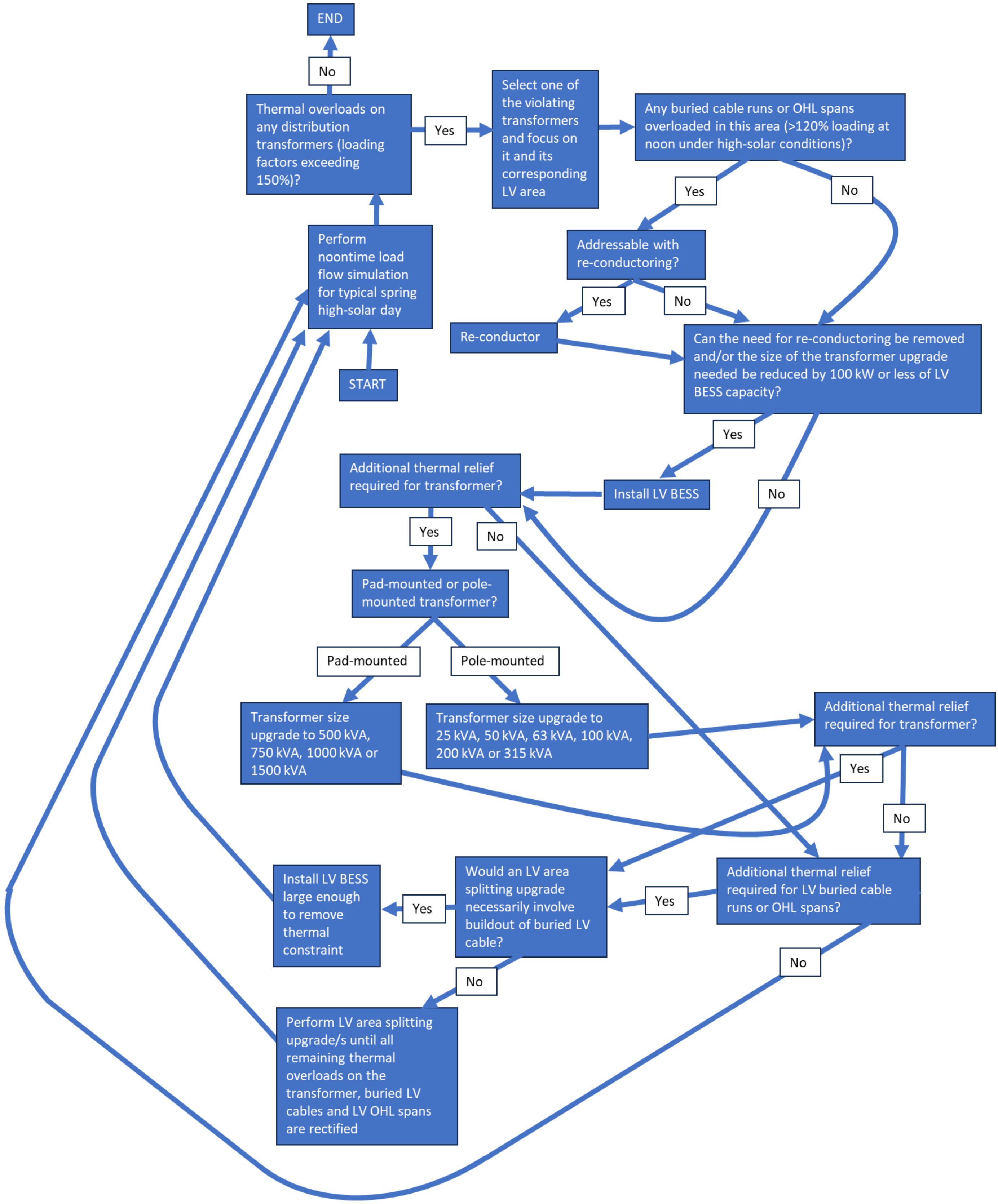

Figure 34 – Decision tree for selection and sizing of solutions to thermal overloads on LV networks and their distribution transformers in the LV BESS solution pathway in case 1b

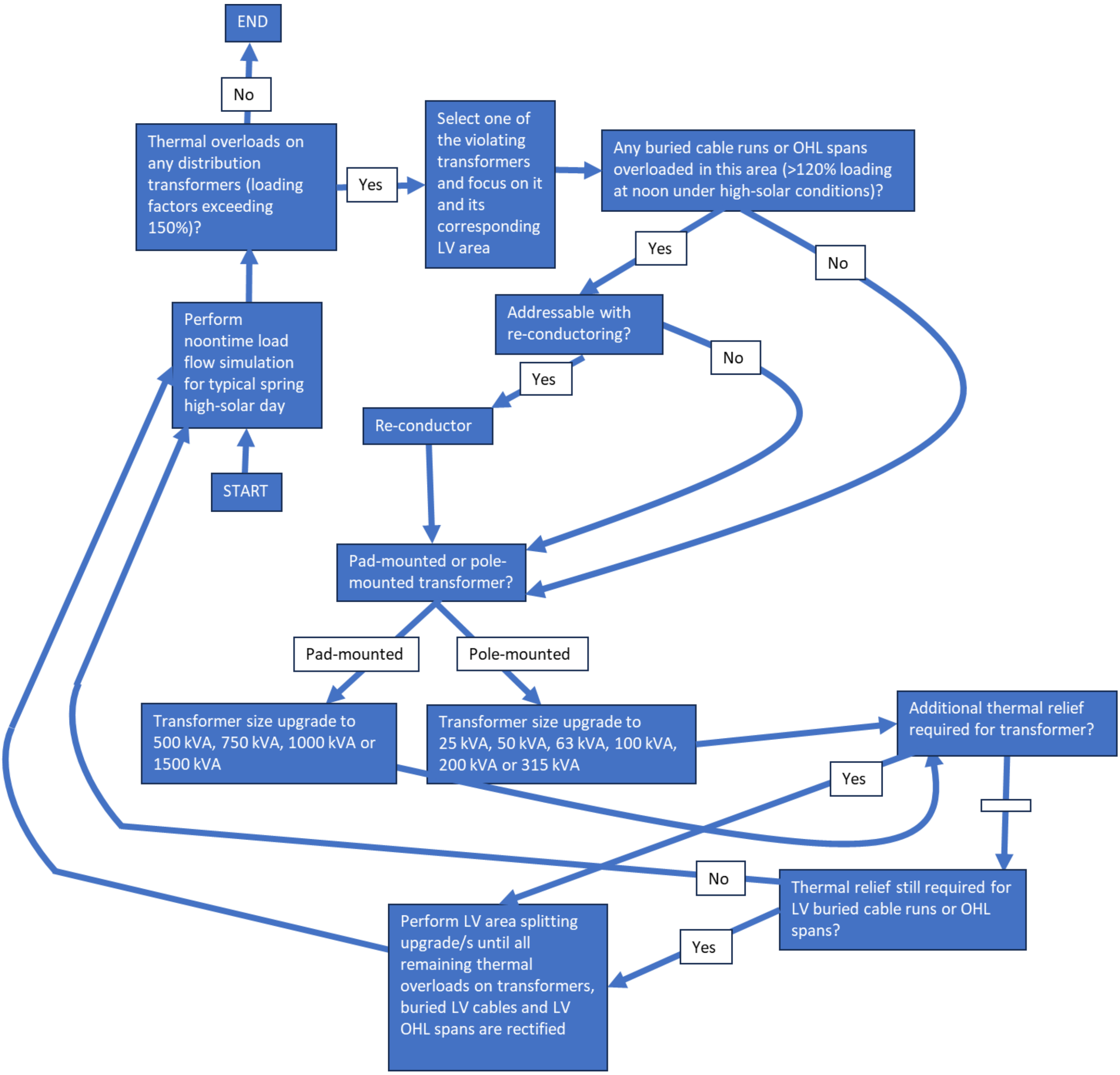

Figure 35 – Decision tree for selection and sizing of solutions to thermal overloads on LV networks and their distribution transformers in the traditional network upgrade solution pathway and the MV BESS solution pathway

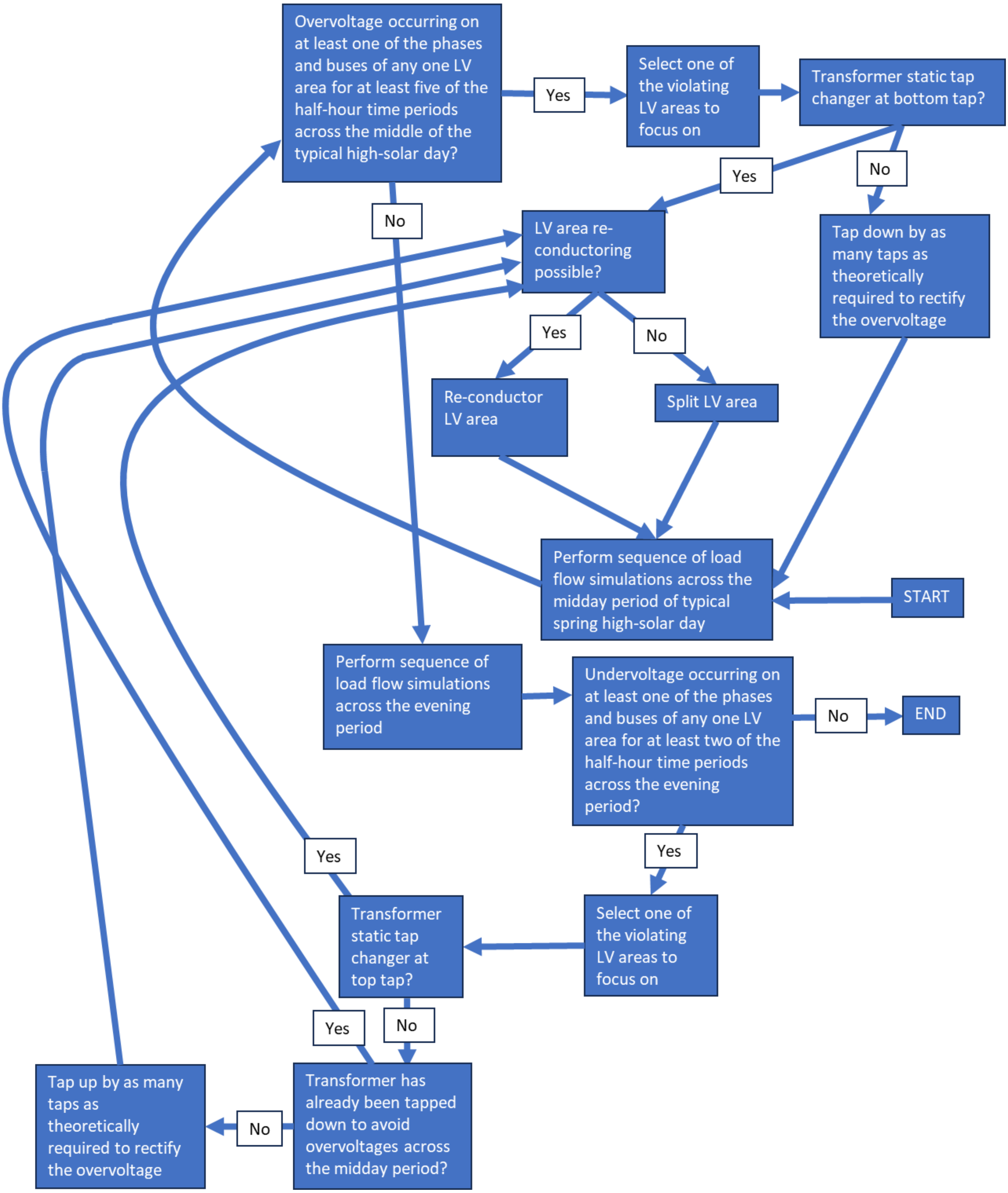

Figure 36 – Decision tree for selection and sizing of solutions to voltage magnitude violations on LV networks in the MV BESS and traditional network upgrades solution pathways in case 2

Appendix C – Additional simulation results

Table 26 – Results for BAU simulations at noon in spring under high solar conditions in variation case 1a

Year	2025	2030	2035	2040	2045	2050
Percentage of LV areas with overvoltage on at least one phase of one LV bus (%)	3.5	5.2	8.3	13.1	19.7	25.8
Percentage of LV areas with thermal overloads on at least one conductor span/run or the transformer (%)	0.0	0.0	2.2	5.7	17.5	32.8
Percentage of LV buses in overvoltage on at least one phase (%)	0.8	1.0	2.1	3.0	4.4	6.0
Proportion of transformers loaded over 100% (%)	0.0	3.1	12.7	24.0	36.2	50.7
Proportion of transformers loaded over 150% (%)	0.0	0.0	1.3	5.2	14.0	25.3
Percentage of the cumulative length of MV OHL spans loaded over 90% (%)	0.0	0.0	0.0	0.0	0.2	0.4
Percentage of the cumulative length of MV buried cable runs loaded over 90% (%)	0.0	0.0	0.0	0.5	7.2	12.7
Percentage of the cumulative length of LV OHL spans loaded over 100% (%)	0.0	0.0	0.2	0.5	1.3	3.3
Percentage of the cumulative length of LV OHL spans loaded over 120% (%)	0.0	0.0	0.1	0.2	0.6	1.4
Percentage of the cumulative length of LV buried cable runs loaded over 100% (%)	0.1	0.2	0.2	0.9	2.9	6.4
Percentage of the cumulative length of LV buried cable runs loaded over 120% (%)	0.0	0.0	0.0	0.2	1.0	3.1
Curtailment (%)	0.8	0.9	1.1	1.3	1.7	2.0
Intended solar power injection (MW)	11.4	21.8	32.5	42.1	53.1	66.7

Table 27 – MV feeder re-conductoring and splitting requirements for each solution pathway in variation case 1a

Year	2025	2030	2035	2040	2045	2050
Lengths of overhead MV re-conductoring (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.16 (0.16)	0.25 (0.41)
Lengths of underground MV re-conductoring (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.40 (0.40)	0.28 (0.28)	0.71 (0.99)
Lengths of overhead MV feeder buildout to facilitate MV feeder splitting (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Lengths of underground MV feeder buildout to facilitate MV feeder splitting (km)						
MV BESS solution pathway / LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

Table 28 – Transformer sizes used in LV area splitting requirements for each solution pathway in case 1

Year	2025	2030	2035	2040	2045	2050
Number of LV area splitting upgrades using 200 kVA transformers						
LV BESS solution	0 (0)	0 (0)	0 (0)	3 (3)	1 (4)	3 (7)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	6 (6)	2 (8)	6 (14)
Number of LV area splitting upgrades using 315 kVA transformers						
LV BESS solution	0 (0)	0 (0)	1 (1)	4 (5)	1 (6)	13 (19)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	4 (4)	12 (16)	12 (28)	22 (50)
Number of LV area splitting upgrades using 500 kVA transformers						
LV BESS solution	0 (0)	0 (0)	0 (0)	3 (3)	5 (8)	17 (25)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	5 (5)	9 (14)	23 (37)
Number of LV area splitting upgrades using 750 kVA transformers						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	3 (4)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	3 (4)
Number of LV area splitting upgrades using 1000 kVA transformers						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	2 (2)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	2 (2)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

Table 29 – Transformer upgrades for each size-to-size category for each solution pathway in case 1

Year	2025	2030	2035	2040	2045	2050
Number of transformer upgrades from 50 kVA to 100 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)
Number of transformer upgrades from 100 kVA to 200 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Number of transformer upgrades from 100 kVA to 315 kVA						
LV BESS solution	0 (0)	0 (0)	1 (1)	0 (1)	0 (1)	0 (1)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	1 (1)	0 (1)	1 (2)	1 (3)
Number of transformer upgrades from 200 kVA to 315 kVA						
LV BESS solution	0 (0)	0 (0)	2 (2)	3 (5)	12 (17)	5 (22)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	2 (2)	4 (6)	7 (13)	4 (17)
Number of transformer upgrades from 300 kVA to 750 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)
Number of transformer upgrades from 315 kVA to 500 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	1 (1)	2 (3)	0 (3)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	1 (1)	2 (3)	0 (3)
Number of transformer upgrades from 315 kVA to 750 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)	0 (1)

MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Number of transformer upgrades from 315 kVA to 1000 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)	0 (1)
Number of transformer upgrades from 500 kVA to 750 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)
Number of transformer upgrades from 500 kVA to 1000 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)	0 (1)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)
Number of transformer upgrades from 750 kVA to 1500 kVA						
LV BESS solution	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	0 (0)	0 (0)	1 (1)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

Table 30 – LV area splitting requirements for each solution pathway in case 1a

Year	2025	2030	2035	2040	2045	2050
Number of LV area splitting upgrades to overhead areas						
LV BESS solution pathway	0 (0)	0 (0)	1 (1)	7 (6)	13 (6)	27 (14)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	4 (4)	18 (14)	36 (18)	58 (22)
Number of LV area splitting upgrades to underground areas						
LV BESS solution pathway	0 (0)	0 (0)	0 (0)	3 (3)	11 (8)	31 (20)
MV BESS solution pathway / Traditional network upgrades solution pathway	0 (0)	0 (0)	0 (0)	5 (5)	18 (13)	41 (23)
Lengths of overhead MV buildout to facilitate LV area splitting upgrades (km)						
LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.15 (0.15)	0.65 (0.50)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.17 (0.17)	0.40 (0.22)	0.59 (0.19)	1.09 (0.50)
Lengths of underground MV buildout to facilitate LV area splitting upgrades (km)						
LV BESS solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.14 (0.14)	0.74 (0.60)	2.54 (1.81)
MV BESS solution pathway / Traditional network upgrades solution pathway	0.00 (0.00)	0.00 (0.00)	0.00 (0.00)	0.19 (0.19)	1.26 (1.07)	3.12 (1.86)
x.xx - Cumulative numbers for each individual five-year period of the study (x.xx) - Aggregating summations over the current and all previous five-year periods						

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