# Jemena Electricity Networks (Vic) Ltd

## Distribution Substation Augmentation

Network Development Strategy

Jemena
bringing energy to life

**An appropriate citation for this paper is:**

Distribution Substation Augmentation

## HISTORY

| Rev No | Date | Description of changes | Author |
|---|---|---|---|
| 1 | 25/06/2021 | First release | Hung Nguyen |
| 2 | 17/12/2024 | Second release | Rodney Bray |

## OWNING FUNCTIONAL GROUP

| | |
|---|---|
| Business Function Owner: | Assets & Operations – Electricity |

## REVIEW DETAILS

| | |
|---|---|
| Review Period: | Revision Date/Last Review Date + 5 years |
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# Abbreviations

| | |
|---|---|
| ADMD | Average Diversified Maximum Demand |
| AS | Australian Standard |
| AFAP | As-Far-As-Practicable |
| CBRM | Condition Based Risk Management |
| CCT | Circuit |
| DER | Distributed Energy Resources |
| DMIA | Demand Management Innovation Allowance |
| DMIS | Demand Management Incentive Scheme |
| DSA | Distribution Substation Augmentation |
| DSS | Distribution Substations |
| ER | Emission Reduction |
| ESV | Energy Safe Victoria |
| EUE | Expected Unserved Energy |
| GIS | Geographic Information Systems |
| GSL | Guaranteed Service Level |
| HBRA | Hazardous Bushfire Risk Areas |
| JEN | Jemena Electricity Network |
| kW | Kilowatt |
| LV | Low Voltage |
| MD | Maximum Demand |
| MWh | MegaWatt Hour |
| NER | National Electricity Rules |
| NPV | Net Present Value |
| PoE | Probability of Exceedance |
| PQ | Power Quality |
| PV | Photo Voltaic |
| SUPS | Substation Utilisation Profiling System |
| UV | Undervoltage |
| VBRC | Victorian Bushfires Royal Commission |
| VCR | Value of Customer Reliability |

# 1. Overview

Jemena Electricity Network (Vic) Ltd. (JEN) is the distribution network service provider for the north-western part of greater Melbourne. We are responsible for consistently delivering a reliable supply of electricity at an efficient, sustainable cost. This includes finding the most appropriate solutions to adequately address constraints on our network and foreseen future threats to the network's performance.

One threat to network performance is overloaded, above capacity, distribution substation transformers and low-voltage distribution circuits. Overloaded assets suffer from reduced lifespans, pose public safety hazards, and lead to poor-quality electricity supply and severe outages.

To manage this threat, we implement an annual distribution substation augmentation program. This program identifies overloaded assets (where demand exceeds capacity) and evaluates whether augmentation or the implementation of non-network solutions can efficiently reduce safety and reliability risks. Over the past 10 years we have replaced on average 27 distribution substations each year. This program has been successful in gradually reducing the number of overloaded assets and in turn improved safety and reliability outcomes over time for our worst-served customers.

This strategy considers whether to halt, reduce or maintain our distribution substation augmentation program, taking into account current capacity utilisation, increasing maximum demand, the electrification of gas and transport, as well our CER Integration Strategy.[1]

We consider four credible options:

- Option 1 – **'Do Nothing'** (base case). This option outlines the network outcomes if we undertake no further action to address overloaded assets.
- Option 2 – **Reduce program** to 13 distribution substations per year.
- Option 3 – **Maintain program** and continue augmenting about 20 distribution substations per year (sites above emergency rating), where the economic benefits exceed the costs.
- Option 4 – **Maintain program until our CER Integration Strategy implements flexible import services (2030/31).** In this option we continue augmenting about 20 substations per annum until flexible import services are available. Then we will reduce augmentation to 10 substations per annum and use flexible import services to manage reliability risks.

We have evaluated these options by considering the quantifiable benefits (reductions in expected unserved energy, valued using the Value of Customer Reliability), an assessment of network risk and by taking into account possible implications from changing customer demand patterns. The estimated costs and benefits are presented in Table 1-1.

**Table 1-1 – Net Present Value of Options ($m, June 2024)**

| Option | Capital Costs[2] | Present Value of Capital & O&M Costs | Present Value of Reliability Benefits | NPV | Ranking |
|---|---|---|---|---|---|
| Option 1 – Do-nothing | 0 | 0 | 0 | 0 | 4 |
| Option 2 – Reduce program | 25.7 | 44.2 | 655.1 | 610.9 | 3 |
| Option 3 – Maintain program | 33.3 | 57.5 | 673.8 | 616.3 | 2 |
| Option 4 – Maintain program until our CER Integration Strategy implements flexible import services | 33.3 | 54.1 | 673.5 | 619.4 | 1 |

[1] The strategy for addressing voltage and power quality issues are covered under "Voltage and PQ Management Strategy".

[2] Capital costs include capitalised overheads and escalations, FY27 to FY31.

Option 4 maximises the net economic benefits with an estimated NPV of $619.4 million over 10 years, primarily driven by avoided expected unserved energy. Option 4 also provides the greatest safety benefits by reducing the number of distribution substations operating beyond their emergency rating.

We also note that, unlike for our higher voltage assets,[3] we do not prepare demand forecasts for our low voltage networks. Instead, we apply 50% of the growth in the summer system peak.[4] This is likely to understate localised demand growth in some networks, particularly given the forecast impact of infill development, electrification of gas and uptake of electric vehicles. As a result, the difference in economic benefits between Options 1&2 and Options 3&4 is likely to be higher than presented in Table 1-1.

Given the factors above, the preferred strategy is Option 4 to maintain the current strategy until our CER Integration Strategy implements flexible import services. The annual capital expenditure for this program is set out in Table 1-2.

**Table 1-2 – Distribution Substation Augmentation (DSA) Program Annual Capital Expenditure ($k, June 2024)[5]**

| Financial Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| DSA – Distribution Substation Load Related ($k) | 4,259 | 4,259 | 4,240 | 4,271 | 4,303 | 4,360 | 4,462 | 4,462 | 2,231 | 2,231 |
| DSA - Low Voltage (LV) Circuit Load Related ($k) | 1,776 | 1,776 | 2,281 | 2,296 | 2,311 | 2,340 | 2,393 | 2,393 | 2,393 | 2,393 |
| **Total ($k)** | 6,035 | 6,035 | 6,521 | 6,567 | 6,614 | 6,700 | 6,855 | 6,855 | 4,624 | 4,624 |

[3] High voltage feeders, zone-substations and sub-transmission assets.

[4] This also means that our forecast does not account for some networks shifting from summer to winter peaking which will result overall load growth growing fast than both summer and winter load growth individually. We only apply 50% of the load growth as an estimate of the load growth which occurs in existing areas. As we discussed later in section 3 this is likely to understate load growth.

[5] The dollars presented includes capitalised overheads and escalations.

# 2. Strategic context

We are committed to providing a safe and reliable electricity supply to all of our customers in a manner that is compliant with all regulatory requirements. To deliver on this commitment, JEN's distribution network assets need to be capable of delivering a reliability and quality of electricity supply that meets its customers' expectations. The assets over their lifecycle, must perform their role reliably and safely within their design capabilities, under all expected operating conditions, at least cost to customers.

Our fleet of distribution substations and their associated low-voltage (LV) circuits serve as network assets that form the key interface between the broader electricity network and our customers. We have approximately 6,530 distribution substations and 13,844 low-voltage circuits that supply the majority of our connected load.

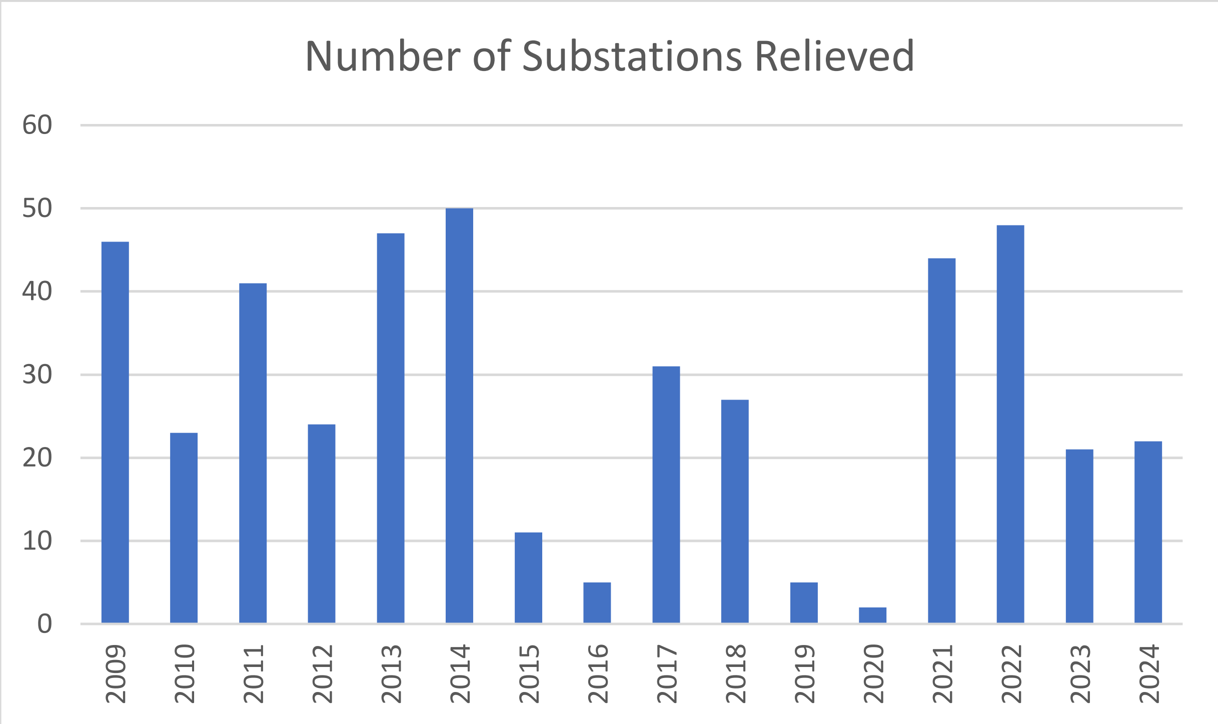
## 2.1 Historic program

Maintaining reliability and quality of electricity supply at the low voltage level of the network is achieved by responding to localised network needs, driven by increases in net electricity maximum demand, and the aggregated behaviour of diverse customer load and generation connected at each distribution substation.

Annually, through our Distribution Substation Augmentation program we identify, through engineering analysis, an optimised list of distribution substations where an asset management intervention investment provides the highest net benefit, considering risk, performance and cost. This generally involves augmenting the network to address the needs of the identified distribution substations and low-voltage circuits, or where a viable, lower-cost non-network solution exists, using this alternative to defer the planned augmentation.

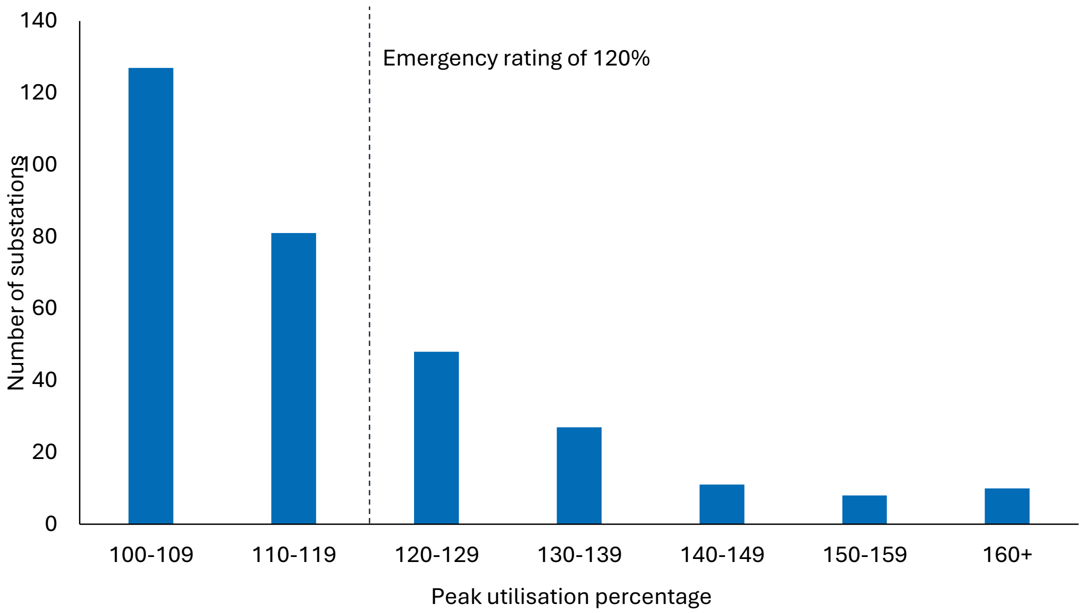
In the period from 2009 to 2024, we completed an average of 28 substation augmentation projects per annum. In the five years from 2020 to 2024, the average rate of project completions was 27 per annum, as shown in Figure 2-1 below.

**Figure 2-1 – Number of Completed Distribution Substation Augmentation Projects**




While we have made steady progress in reducing the number of substations operating beyond their rated cyclic capacity, 312 out of the 6,812 distribution substations (5.05%) in the JEN supply area operate at over 100% of rated cyclic capacity and 104 (1.68%) operate at over 120% of rated cyclic capacity (also known as "emergency rating"). Figure 2-2 shows the distribution of peak utilisation rate among substations above 100% of rated cyclic capacity.

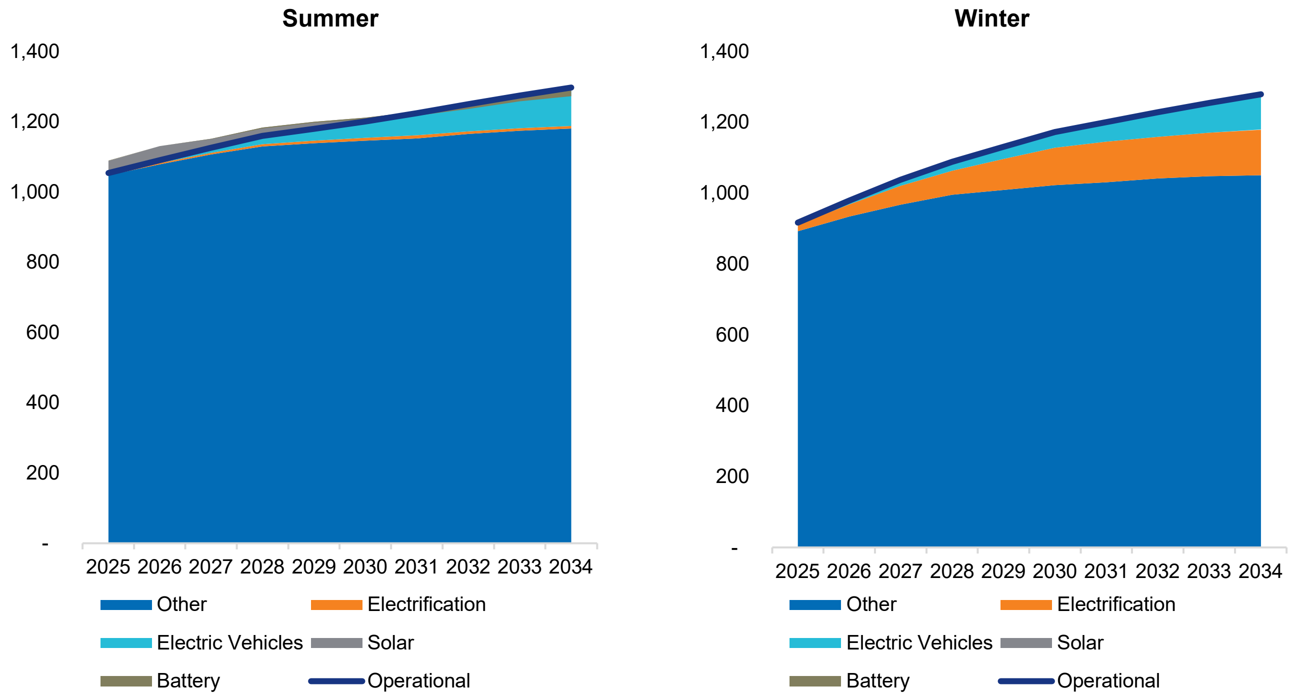
**Figure 2-2 – Number of overloaded substations by peak utilisation percentage (2023)**



## 2.2 Growth in demand

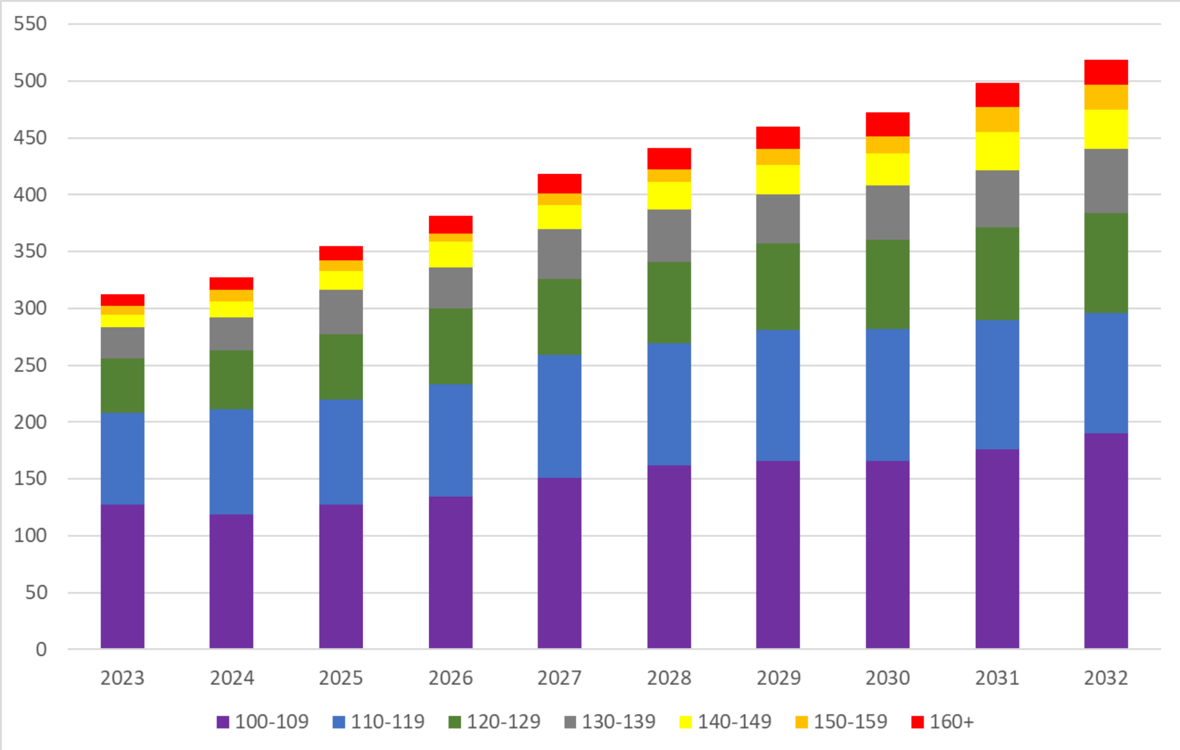
As shown in Figure 2-3 maximum demand at the system level is forecast to continue to grow. This is comprised of those customer connections which trigger a new distribution substation, and organic growth including other infill development, growth in household appliances, electrification of gas and transport, which place additional demands on our existing distribution substation assets.

**Figure 2-3 – Maximum demand forecast (POE10)**




Applying half the growth of the summer maximum demand forecast (to only account for organic growth on our existing distribution substation assets), without further investment, to current observed loads we expect that the number of distribution substations will significantly increase. This is illustrated by Figure 2-4 which shows the number of overloaded distribution substations by band (100 – 109%, 110-119% etc.). The number of distribution substations will increase from 312 in 2023 to 519 by 2032 and the number of LV circuits will increase from 380 to 540 over the same time period.

**Figure 2-4 Forecast Number of Overloaded Distribution Substations by Utilisation (%) (Do Nothing)**




## 2.3 Consequences of demand beyond capacity

Growing maximum demand results in localised loads exceeding the capacity of our low-voltage lines and distribution substations. These network constraints result in:

- **Premature asset failures and higher costs due to thermal overloading.** Excessive loading generates high temperatures in excess of 110ºC, which deteriorates insulation material and increases the risk of gas bubbling resulting in premature failure.
- **Poor power quality exceeding regulatory limits** – caused by high load, imbalance and harmonic flows through network impedances – could result in damage to customer appliances.
- **Power outages** – caused by the operation of distribution transformer fuses or low-voltage circuit fuses. Supply restoration time can be many hours in the case of multiple coincident outages due to the radial nature of the low-voltage networks having virtually no transfer options during times of maximum demand.
- **Risks to customer health and wellbeing** – as power outages occur at times of extreme heat. We note that during heatwave events, the duration of the supply interruptions can be longer. This is because our low-voltage network supplied by the distribution substations is radial with little redundancy or sharing of capacity to allow operational flexibility under high loading conditions
- **Risks to employees, the public and the environment**– caused by excessive heat build-up. Failure of transformers, located in public places and often with no cladding (pole mounted) or only minimal cladding (ground mounts), can lead to a risk of fire, explosion of expulsion of boiling oil due to failure. This poses a safety risk to employees, the public and the environment.

These outcomes reduce the reliability, safety, and quality of our network services and result in either higher cost or higher risk to our customers.

## 2.4 Consumer Energy Resources

One aspect of our Consumer Energy Resource (CER) Integration Strategy is the development of our Distributed Energy Resource Management System. This platform aims to achieve near real-time optimised control of CER active power operating envelopes to keep the grid stable. This includes enabling flexible export and import distribution services using Dynamic Operating Envelopes in 2030/31.

Flexible services provide an alternative option to help managing overloading on substations and could be a more economic alternative to traditional augmentations.

# 3. Assessment methodology and assumptions

This section explains the method and underlying assumptions that are used to evaluate each of the feasible options and lists important inputs applied in the cost-benefit analysis.

Our approach is to compares the costs – capital and ongoing Operating and Maintenance (O&M) costs – of each credible option against the consumer costs of losing electricity supply in that same option. The cost to consumers is equal to the Value of Customer Reliability (VCR) multiplied by the Expected Unserved Energy (EUE).

**Table 3-1 – Assumptions**

| Assumption | Value |
|---|---|
| Maximum summer demand growth (as a percentage of the JEN service area maximum demand growth)[6] | 50% |
| Value of Customer Reliability ($/kWh) | 47.905 |
| 10% PoE / 50% PoE weighting | 30% / 70% |
| Power factor | 0.9 |
| Distribution substation upgrade unitised cost (direct, June 2024) | $185k |
| Low voltage circuit upgrade unitised cost (direct, June 2024) | $90k |
| Operational and Maintenance Expenditure | 1% |
| Discount rate | 5.5% |
| Analysis period (years) | 10 |

Unlike for our higher voltage assets,[7] we do not prepare demand forecasts for our low voltage networks.

Instead, we apply 50% of the growth in the summer system peak.[8] The 50% is an estimate of the load growth which occurs in existing areas (rather than greenfield areas). This is a conservative (low) assumption given that:

- Electrification of gas heating and uptake of electric vehicles are driving 40 – 60% of load growth between 2025 and 2031.[9]
- Significant load growth will be driven by infill, given that 70% of new Victorian homes will be built in established areas.[10]
- Load growth will be faster in some networks where housing development, electrification or electric vehicle uptake is concentrated.
- Some networks will likely shift from summer peaking to winter peaking – resulting in overall load growth exceeding both summer and winter load growth.

We also note that applying our system forecast includes the moderating impact of our Customer Energy Resources (CER) Strategy on demand, such as the impact of solar and changes in electric vehicle charging patterns.

Risk costs are calculated based on energy at risk above the cyclic rating for distribution substations. Volumes of substations are based on those distribution substations whose risk costs exceed the cost of the augmentation.

[6] To distinguish between organic growth on existing substations, and new substations established as part of customer connections.

[7] High voltage feeders, zone-substations and sub-transmission assets.

[8] This also means that our forecast does not account for some networks shifting from summer to winter peaking which will result overall load growth growing fast than both summer and winter load growth individually.

[9] AEMO's is forecasting that 47% of summer and 62% of winter POE50 load growth will be driven by electrification and electric vehicles.

[10] Victoria's Housing Statement Progress Statement, available here.

Volumes for LV circuits are based on a deterministic approach identifying the number of LV circuits expected to exceed their emergency ratings.

We note that non-network operations could be preferred over network augmentation. Options include using standby generators, embedded generators or demand side management (e.g. customer off-peak usage incentives of interruptible load agreements).

The optimal selection of network or non-network option will occur as part of our annual program, which includes consideration of the most economic option to address a given constraint. For the purposes of this strategy, which is to determine whether to maintain reduce or half our program, we have considered that network and non-network options have a similar cost.

# 4. Options

## 4.1 Option 1 – 'Do Nothing'

Option 1 is the base case against which the other options are compared. It sets the baseline with an NPV of zero. and considers how the escalating value of expected unserved energy due to customer outages grows over the planning outlook period.

No augmentation works are considered under this option. It is assumed we will only replace or augment our network after failure. This option will see an increase in the expected quantity of unserved energy from 1,020 MWh in FY25 to 2,169 MWh by FY32. The number of interruptions on the low-voltage network and number of transformer damage events will also increase.

The likelihood of customer supply interruptions associated with overloaded distribution substations increases in accordance with the growth across the network, as outlined in Table 4-1.

**Table 4-1 – Residual reliability risk, augmentation volumes and costs ($k or $m, June 2024) [11] under Option 1**

| Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| No. of Substations Augmented | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| No. of Low Voltage Circuits Augmented | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Remaining No. of Substations > Emergency rating | 135 | 148 | 159 | 172 | 179 | 190 | 208 | 223 | 235 | 245 |
| Expected Unserved Energy (EUE) (MWh) | 1,020 | 1,195 | 1,397 | 1,493 | 1,632 | 1,785 | 1,969 | 2,169 | 2,376 | 2,556 |
| Value of Expected Unserved Energy ($m) | 48.8 | 57.3 | 66.9 | 71.5 | 78.2 | 85.5 | 94.3 | 103.9 | 113.8 | 122.5 |
| Substations Capital Cost ($k) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LV Circuits Capital Cost ($k) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Under this option, the quantity of expected unserved energy rises consistently in each year of the forecast and so does the total number of overloaded substations. A few substations will experience extreme levels of overloading, leading to early failure of assets. These costs of replacing these assets in a reactive manner have not been included.

There is also a significant possibility of multiple concurrent failures, leading to long outages and a slow and difficult recovery process. Failing assets can endanger the public and have the potential to start fires.

[11] The dollars presented includes capitalised overheads and escalations.

## 4.2 Option 2 – Reduce program

Under Option 2, the rate of augmentation is reduced to 13 substations and 21 LV circuits per annum and assumes that we only address the most urgent cases.

**Table 4-2 – Reliability benefit, augmentation volumes and costs ($k or $m, June 2024)[12] under Option 2**

| Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| No. of Substations Augmented | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 | 13 |
| No. of Low Voltage Circuits Augmented | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Remaining No. of Substations > Emergency rating | 109 | 109 | 107 | 107 | 101 | 99 | 104 | 106 | 105 | 102 |
| Avoided EUE Benefit (MWh) | 879 | 1,081 | 1,302 | 1,402 | 1,552 | 1,710 | 1,905 | 2,110 | 2,321 | 2,510 |
| Value of Avoided EUE Benefit ($m) | 42.1 | 51.8 | 62.4 | 67.2 | 74.4 | 81.9 | 91.3 | 101.1 | 111.2 | 120.2 |
| Substations Capital Cost ($k) | 2,769 | 2,769 | 2,756 | 2,776 | 2,797 | 2,834 | 2,900 | 2,900 | 2,900 | 2,900 |
| LV Circuits Capital Cost ($k) | 1,776 | 1,776 | 2,281 | 2,296 | 2,311 | 2,340 | 2,393 | 2,393 | 2,393 | 2,393 |

This investment will result in the number of heavily loaded substations and low-voltage circuits. This option will not address the safety obligations related to ensuring that we reduce risk to As-Far-As-Practicable (AFAP) response to grossly overloaded distribution transformers[13]. It will also mean that our worst-served customers today will remain poorly served into the future.

## 4.3 Option 3 – Maintain program

Option 3 sets augmentation volumes such that there are as few as possible substations overloaded by 120% or more of cyclic rating. 20 sites per annum are augmented in this scenario. Whilst this is at a marginally reduced volume compared to historical averages, it is forecast to maintain overall reliability outcomes. The number of overloaded LV circuits is forecast to be 21 per annum.

[12] The dollars presented includes capitalised overheads and escalations.

[13] Grossly overloaded transformers are those loaded to more than 120% of their cyclic rating, a proxy for their short-time emergency rating.

**Table 4-3 – Reliability benefit, augmentation volumes and costs ($k or $m, June 2024)[14] under Option 3**

| Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| No. of Substations Augmented | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 |
| No. of Low Voltage Circuits Augmented | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Remaining No. of Substations > Emergency rating | 100 | 93 | 84 | 77 | 64 | 55 | 53 | 48 | 40 | 30 |
| Avoided EUE Benefit (MWh) | 933 | 1,133 | 1,342 | 1,457 | 1,605 | 1,760 | 1,950 | 2,152 | 2,360 | 2,544 |
| Value of Avoided EUE Benefit ($m) | 44.7 | 54.3 | 64.3 | 69.8 | 76.9 | 84.3 | 93.4 | 103.1 | 113.1 | 121.9 |
| Substations Capital Cost ($k) | 4,259 | 4,259 | 4,240 | 4,271 | 4,303 | 4,360 | 4,462 | 4,462 | 4,462 | 4,462 |
| LV Circuits Capital Cost ($k) | 1,776 | 1,776 | 2,281 | 2,296 | 2,311 | 2,340 | 2,393 | 2,393 | 2,393 | 2,393 |

Reducing the number of substations operating above their emergency rating will also reduce safety risks from failing substations.

## 4.4 Option 4 – Maintain program until our CER Integration Strategy implements flexible import services

Option 4 involves continuing our Distribution Substation Augmentation program at a marginally reduced volume and optimising the expenditure using Flexible Import services.

Under this option, consistent with Option 3, 20 substations per annum will be augmented up until 2032. Thereafter, it is expected that JEN's planned introduction of Flexible Import and Flexible Export services will enable non-network management of some overloaded transformers and defer further augmentation[15] and the rate will be reduced to 10 sites per annum. As in Option 3, the number of overloaded LV circuits is forecast to be 21 per annum.

[14] The dollars presented includes capitalised overheads and escalations.

[15] Our forecast has already factored in a high level of export for residential customers, (i.e., 5 kW per phase in our Model Standing Offers). Furthermore, peak demand occurs in the late afternoon with peak demand time shifting due to solar PV already being incorporated in the total network peak demand, which is the key input for this DSA model.

**Table 4-4 – Reliability benefit, augmentation volumes and costs ($k or $m, June 2024)[16] under Option 4**

| Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| No. of Substations Augmented | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 10 | 10 |
| No. of Low Voltage Circuits Augmented | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 | 21 |
| Remaining No. of Substations > Emergency rating | 100 | 93 | 84 | 77 | 64 | 55 | 53 | 48 | 50 | 50 |
| Avoided EUE Benefit (MWh) | 933 | 1,133 | 1,342 | 1,457 | 1,605 | 1,760 | 1,950 | 2,152 | 2,358 | 2,539 |
| Value of Avoided EUE Benefit ($m) | 44.7 | 54.3 | 64.3 | 69.8 | 76.9 | 84.3 | 93.4 | 103.1 | 112.9 | 121.6 |
| Substations Capital Cost ($k) | 4,259 | 4,259 | 4,240 | 4,271 | 4,303 | 4,360 | 4,462 | 4,462 | 2,231 | 2,231 |
| LV Circuits Capital Cost ($k) | 1,776 | 1,776 | 2,281 | 2,296 | 2,311 | 2,340 | 2,393 | 2,393 | 2,393 | 2,393 |
| Flexible Imports Operational Cost ($k) | 0 | 0 | 0 | 0 | 0 | 0 | 906 | 814 | 883 | 815 |

Similar to Option 3, from an outage perspective, this investment (subject to the uptake of Flexible Import Services by our customers in these areas) will result in the augmentation of all of the most heavily loaded substations and low-voltage circuits, generating benefits to customers in the form of reduced service interruptions.

[16] The dollars presented includes capitalised overheads and escalations.

# 5. Economic evaluation

Cost-benefit analysis is used to compare the merits of the options considered and the required annual volumes. It involves calculating the present value of the net benefits (avoided risk less costs) associated with each option. The key assessment used to compare the options considered is the present value of the net benefits (the net present value or NPV) being the avoided EUE less costs. The NPV analysis for each of the credible options considered is presented in Table 5-1.

Option 4 maintain program until our CER Integration Strategy implements flexible import services has the highest NPV.

**Table 5-1 – Net Present Value of Options ($m, June 2024)**

| Option | Capital Costs[17] | Present Value Total Costs | Present Value Benefits | NPV | Ranking of NPV |
|---|---|---|---|---|---|
| Option 1 – Do-nothing | 0 | 0 | 0 | 0 | 4 |
| Option 2 – Reduce program | 25.7 | 44.2 | 655.1 | 610.9 | 3 |
| Option 3 – Maintain program | 33.3 | 57.5 | 673.8 | 616.3 | 2 |
| Option 4 – Maintain program until our CER Integration Strategy implements flexible import services | 33.3 | 54.1 | 673.5 | 619.4 | 1 |

[17] Capital costs include capitalised overheads and escalations, FY27 to FY31.

# 6. Findings and recommendation

The purpose of this strategy is to consider whether to halt, reduce or maintain our distribution substation augmentation program, taking into account current capacity utilisation, increasing maximum demand, the electrification of gas and transport, as well our CER Integration Strategy.

Continuing our current program at marginally reduced volumes and introducing flexible import services[18] (Option 4) is the recommended option based on:

- It delivers the greatest net economic benefits.
- It delivers the greatest reduction of safety and reliability risks (in particular in the form of long outages in the middle of a heatwave) for our worst served customers.
- Maintains reliability outcomes for our overall network.
- Limitations around the applicability of our system demand forecast to our low voltage network – which meant that demand growth may be higher than we account for in existing areas and spatially concentrated. This may understate the relative benefits of maintaining our current approach.

Table 6-1 shows the level of expenditure associated with our preferred Option 4.

**Table 6-1 – Distribution Substation Augmentation (DSA) Program Annual Capital Expenditure ($k, June 2024)[19]**

| Financial Year | FY25 | FY26 | FY27 | FY28 | FY29 | FY30 | FY31 | FY32 | FY33 | FY34 |
|---|---|---|---|---|---|---|---|---|---|---|
| DSA – Distribution Substation Load Related ($k) | 4,259 | 4,259 | 4,240 | 4,271 | 4,303 | 4,360 | 4,462 | 4,462 | 2,231 | 2,231 |
| DSA - Low Voltage (LV) Circuit Load Related ($k) | 1,776 | 1,776 | 2,281 | 2,296 | 2,311 | 2,340 | 2,393 | 2,393 | 2,393 | 2,393 |
| Total ($k) | 6,035 | 6,035 | 6,521 | 6,567 | 6,614 | 6,700 | 6,855 | 6,855 | 4,624 | 4,624 |

[18] Our approach can be adjusted once our CER Integration Strategy implements flexible imports. This will enable our program to be reduced from 2032, depending on the costs of accessing these services.

[19] The dollars presented includes capitalised overheads and escalations.