# Jemena Electricity Networks (Vic) Ltd

## Sunbury Zone Substation (SBY) and Sydenham Zone Substation (SHM) Supply area Capacity Constraint

RIT-D Stage 1: Options Screening Report

# Executive summary

Jemena Electricity Networks (Vic) Ltd (**JEN**) is the licensed electricity distributor for the northwest of Melbourne's greater metropolitan area. The service area ranges from Gisborne South, Clarkefield and Mickleham in the north to Williamstown and Footscray in the south and from Hillside, Sydenham and Brooklyn in the west to Yallambie and Heidelberg in the east. JEN supplies electricity distribution services to more than 384,000 customers.

Our customers expect us to deliver a reliable electricity supply at an efficient cost. To do this, we must choose the most efficient solution to address current and emerging network limitations. This means choosing the prudent solution that maximises the present value of net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**).

## Identified Need

Sunbury (**SBY**) zone substation and Sydenham (**SHM**) are owned and operated by JEN, providing power to approximately 38,223 JEN customers in Melbourne's outer northwest. SBY and SHM service a diverse mix of rural, developed urbanised, and greenfield residential and commercial growth areas across Sunbury, Gisborne South, Clarkefield, Diggers Rest, Wildwood, Plumpton, Fraser Rise, Bonnie Brook, Hillside, Bulla, Sydenham, Calder Park and Taylors Lakes.

SBY and SHM are the main sources of electricity supply for the Sunbury/Diggers Rest Growth Corridor[1] of Melbourne, an area experiencing rapid development and increasing demand. Both zone substations are currently operating at high utilisation levels, with forecasts indicating continued pressure on capacity. The available transformation capacity provided by both SBY and SHM zone substations to service the area is declining over time. As such, the high growth and high asset utilisation levels will have increasing consequences for the reliability of electricity supply to JEN's customers within the Sunbury and Sydenham supply area.

The identified need for this Regulatory Investment Test for Distribution (**RIT-D**) is to maintain the reliability of supply in the Sunbury and Sydenham supply area whilst accommodating new customer connections, and growth in customer maximum demand.

## Approach to screening options

JEN has developed a set of potential network solutions aimed at addressing the identified need. It has also investigated whether viable non-network or stand-alone power system (**SAPS**) solutions exist, in which case JEN is required to publish an options screening report and request stakeholder submissions, as detailed in National Electricity Rules (**NER**) clause 5.17.4, paragraph (e).

In the event that there are no potential credible non-network or SAPS options that could address the identified need (or any combination of those options with or without a network option), JEN is instead required to publish a Notice of Determination in accordance with the requirements of clause 5.17.4, paragraphs (c) and (d) of the NER.

This report assesses the viability of potential non-network and SAPS options as credible alternatives or supplements to the identified network options. The evaluation focuses on whether these options can effectively address any forecast supply shortfalls at SBY and SHM over the 10-year planning horizon, ensuring they can meet forecast demand within the Sunbury-Diggers Rest Growth Corridor.

The minimum level of network support required for the underlying growth in customer maximum demand for the supply area is up to 33 MW over the 10-year period. Smaller (or staged) solutions of at least 11MW in the first year with 2 MW (per annum cumulative) up to 33MW, could provide sufficient capacity to address this part of the identified need.

[1] Victorian Planning Authority – The Sunbury/Digger Rest Growth Corridor Plan.

## Summary of findings

The decision criteria used by JEN to assess the potential credibility of non-network and SAPS options included:

- **Addresses the identified need**: reduces or eliminates the supply reliability risks associated with the identified need.
- **Technically feasible**: there are no technical constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 1–1 shows the rating scale JEN has applied for assessing credibility of non-network and SAPS options.

**Table 1–1: Assessment criteria rating**

| Rating | Colour Coding |
|---|---|
| Does not meet the criterion | |
| Does not fully meet the criterion (or uncertain) | |
| Clearly meets the criterion | |

Table 1–2 shows the initial assessment of potential non-network and SAPS options against the RIT-D criteria.

**Table 1–2: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Economic | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Generation using gas turbines or diesel | | | | |
| 1.2 Generation using grid-scale solar and storage | | | | |
| 1.3 Standby generation (existing large customer) | | | | |
| 1.4 Storage only using grid-scale batteries | | | | |
| **2.0 Demand Management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power and storage systems | | | | |
| 2.3 Broad-based demand response | | | | |
| 2.4 Targeted demand response | | | | |

Based on these results, JEN has concluded that some of the potential non-network or SAPS options investigated (or a combination of options) are credible options that could adequately address the identified need.

Hence, consistent with NER clause 5.17.4(b), JEN has published this options screening report as part of the first phase of consultation under the RIT-D. The contents of this options screening report have been developed consistent with NER clause 5.17.4(e).

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# Glossary

| | |
|---|---|
| Amperes (A) | Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps. |
| Capital expenditure (CAPEX) | Expenditure to buy fixed assets or to add to the value of existing fixed assets to create future benefits. |
| Contingency (or ‘N-1’ condition) | An event affecting the power system that is likely to involve the failure or removal from operational service of one or more generating units and/or network elements. |
| Energy-at-risk | The energy at risk of not being supplied if a contingency occurs, and under system normal operating conditions. |
| Expected unserved energy (EUE) | Refers to an estimate of the probability weighted, average annual energy demanded (by customers) but not supplied. The EUE measure is transformed into an economic value, suitable for a cost-benefit analysis, using the value of customer reliability (VCR), which reflects the economic cost per unit of unserved energy. |
| Load-at-risk | The maximum demand at risk of not being supplied if a contingency occurs, and under system normal operating conditions. |
| Jemena Electricity Network (JEN) | One of five licensed electricity distribution networks in Victoria, the JEN is 100% owned by Jemena and services over 370,000 customers covering north-west greater Melbourne. |
| Maximum Demand (MD) | The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year. |
| Megavolt Ampere (MVA) | Refers to a unit of measurement for the apparent power in an electrical circuit. |
| Network | Refers to the system of physical assets required to transfer electricity to customers. |
| Network augmentation | An investment that increases network capacity to prudently and efficiently manage customer service levels and power quality requirements. Augmentation usually results from growing customer demand. |
| Network capacity | Refers to the network’s capability to transfer electricity to customers. |
| Non-network option | Any measure to reduce peak demand and/or increase local or distributed generation/supply options. |
| Probability of Exceedance (PoE) | The likelihood that a given level of maximum demand forecast will be met or exceeded in any given year. |
| Regulatory Investment Test for Distribution (RIT-D) | An economic viability test that establishes consistent, clear and efficient planning processes for assessing and consulting on distribution network investments over a prescribed limit. |
| Stand Alone Power System | An embedded power system that operates disconnected (islanded) from the network. |
| System Normal (or ‘N’ condition) | The condition where no network assets are under maintenance or forced outage, and the network is operating in a normal configuration. |
| Value of Customer Reliability (VCR) | Represents the dollar per MWh value that customers place on a reliable electricity supply (and can also indicate customer willingness to pay for not having supply interrupted). |
| Zone Substation | Refers to the location of transformers, ancillary equipment and other supporting infrastructure that facilitate the electrical supply to a particular zone in the network. |

| | |
|---|---|
| 10% POE condition (summer) | Refers to an average daily ambient temperature of 32.9ºC, with a typical maximum ambient temperature of 42ºC and an overnight ambient temperature of 23.8ºC. |
| 50% POE condition (summer) | Refers to an average daily ambient temperature of 29.4ºC, with a typical maximum ambient temperature of 38.0ºC and an overnight ambient temperature of 20.8ºC. |
| 50% POE and 10% POE condition (winter) | Refers to an average daily ambient temperature of 7ºC, with a typical maximum ambient temperature of 10ºC and an overnight ambient temperature of 4ºC. |

# Abbreviations

| | |
|---|---|
| AEMO | Australian Energy Market Operator |
| AER | Australian Energy Regulator |
| CB | Circuit Breaker |
| CBRM | Condition Based Risk Management |
| DPAR | Draft Project Assessment Report |
| EUE | Expected Unserved Energy |
| HV | High Voltage |
| JEN | Jemena Electricity Networks (Vic) Ltd |
| kV | Kilo-Volts |
| LV | Low Voltage |
| MD | Maximum Demand |
| MVA | Mega Volt Ampere |
| MVAr | Mega Volt Ampere Reactive |
| MW | Mega Watt |
| MWh | Megawatt hour |
| N | System normal condition |
| N-1 | Single contingency condition |
| NEM | National Electricity Market |
| NER | National Electricity Rules |
| NPV | Net Present Value |
| NSP | Network Service Provider |
| O&M | Operations and Maintenance |
| PLN | Plumpton Zone Substation |
| POE | Probability of Exceedance |
| PV | Photovoltaic |
| RIT-D | Regulatory Investment Test for Distribution |
| SAPS | Stand Alone Power System |
| SBY | Sunbury Zone Substation |
| SHM | Sydenham Zone Substation |
| VCR | Value of Customer Reliability |

# 1. Introduction

This section outlines the purpose of the Regulatory Investment Test for Distribution (RIT-D) in relation to the Sunbury and Sydenham supply area.

## 1.1 RIT-D purpose and process

Jemena Electricity Networks (Vic) Ltd (**JEN**), being a regulated distribution network service provider (**DNSP**), is required to undertake the RIT-D consultation process in accordance with clause 5.17 of the National Electricity Rules (**NER**). The purpose of the RIT-D is to identify the investment option that best addresses an identified need on JEN's electricity network, that is the credible option that maximises the present value of the net economic benefit to all those who produce, consume and transport electricity in the National Electricity Market (**NEM**) as well as that arising from changes in Australia's greenhouse gas emissions (the preferred option).[2] The identified need in this RIT-D is to maintain the reliability of supply in the Sunbury and Sydenham supply area whilst accommodating new customer connections, and growth in customer maximum demand.

The RIT-D applies in circumstances where a network limitation (an "identified need") exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $7 million[3].

As part of the RIT-D process, distribution businesses must also consider non-network and standalone power system (**SAPS**) options when assessing credible options to address the identified need. We are also required to screen for non-network and SAPS options by determining whether they are likely to form a:

- Potential credible option(s) or;
- Significant part of one or more potential credible options to address the identified need.

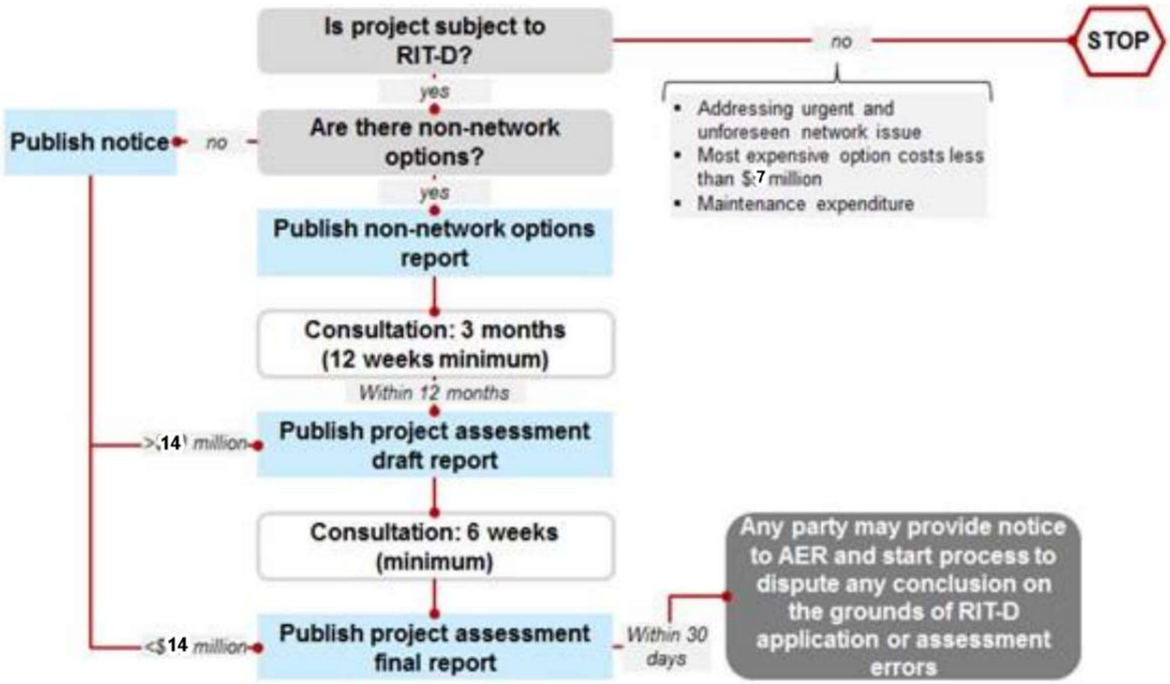
It is for these reasons that we develop this options screening report. Our evaluation shows that some of the potential non-network or SAPS options JEN has investigated (or a combination of options) are credible options that could adequately address the identified need.

The RIT-D process is summarised in Figure 1–1.

[2] The net economic benefit is defined in the NER to include the sum of (a) the net economic benefit, other than of changes to Australia's greenhouse gas emissions, to all those who produce, consumer or transport electricity in the NEM; and (b) the net economic benefit of changes to Australia's greenhouse gas emissions, whether or not that net benefit is to those who produce, consume or transport electricity in the NEM.

[3] Source: AER 2024 RIT and APR cost thresholds review (November 2024).

**Figure 1–1: The RIT-D Process**[4]




## 1.2 Structure of this report

This options screening report:

- Summarises the non-network and SAPS screening requirements and the assessment approach (Section 2).
- Describes the identified need JEN is aiming to address (Section 3.1).
- Describes the network options evaluated to date (Section 3.2).
- Describes the potential of non-network and/or SAPS options to help address the identified need (Section 6.1).
- States the conclusion reached on potential non-network and SAPS options, and next steps (Section 6.2).

[4] Source: [AER Application Guidelines RIT-D]() (November 2024).

# 2. Screening requirements and approach

This section:

- Outlines the option screening requirements as set out in the:
  - AER - Regulatory Investment Test for Distribution application guidelines - 2024 - Version 6; and
  - National Electricity Rules (NER), Version 230, Dated 8th June 2025.
- Describes JEN's approach for assessing the credibility of non-network and SAPS options.

## 2.1 Definitions

Section 6.1 of AER's Application Guidelines, defines feasible non-network and SAPS options to include:

- Any measure or program targeted at reducing peak demand (e.g. direct load control schemes, broad-based or targeted demand response programs)
- Increased local or distributed generation/supply options (e.g. capacity for standby power from existing or new embedded generators or using energy storage systems and load transfer capacity).

Chapter 10 of the NER defines an **identified need** as the objective a Network Service Provider (NSP) seeks to achieve by investing in the network. Further, section 3.1 of the AER's Application Guidelines, states that:

- A network, non-network or SAPS option may address an identified need.
- An identified need consist of an increase in the sum of consumer and producer surplus in the NEM, or may be for reliability corrective action as per NER 5.17.1(b), where the NER 5.10.2 defines reliability corrective action as a NSP investment in its network to meet the service standards linked to the technical requirements of schedule 5.1 or in applicable regulatory instruments and which may consist of network options or non-network options
- RIT-D proponents should articulate the identified need as the achievement of an objective or end, and not simply the means to achieve the objective or end. This approach helps avoid bias in the development of credible options.

  Further, the objective should be expressed as a proposal to electricity consumers and be clearly stated and defined in the RIT-D report. Framing the identified need as a proposal to consumers should assist the RIT-D proponent in demonstrating why the benefits to consumer would outweigh the costs. A description of an identified need should not mention or explain a particular method, mechanism or approach to achieve a desired outcome.

A **credible option** is defined in clause 5.15.2(a) of the NER as an option, or group of options that:

- Addresses the identified need.
- Is (or are) economically and technically feasible; and
- Can be implemented in sufficient time to meet the identified need.

Clause 5.15.2(c) requires that in applying the RIT-D, the RIT-D proponent must consider all options that could be reasonably classified as credible options without bias to:

- Energy source;
- Technology;
- Ownership; and

- Whether it is a network or non-network solution.

The AER's Application Guidelines provided further guidance on how to interpret the requirements of the NER in relation to determining a reasonable number and range of credible options. We have had regard to these guidance as shown in the succeeding sections of this report.

In summary, JEN has interpreted the guidance to mean that a credible option may comprise both non-network and network components, which together, through an integrated solution, can effectively meet the identified need. For example, where a non-network solution reduces peak demand so that the RIT-D proponent can install smaller capacity or less costly equipment (Application Guidelines, Example 22, page 77).

## 2.2 Approach

JEN's approach to identifying and assessing the credibility of potential non-network and SAPS options for this options screening report includes:

- Describing the identified need being addressed by this project including the network limitations driving the proposed investment such as the capacity and demand; and the minimum contribution required if non-network options are to be potentially credible.
- Describing the credible network options considered including a preliminary designation of the preferred network solution.
- Documenting the initial assessment of the range of non-network options against the criteria in clause 5.15.2(a) of the NER (see section 2.1 above).
- Assessing whether there is sufficient and appropriate evidence to determine if there are any potential credible non-network or SAPS options and identifying any issues that require further examination.

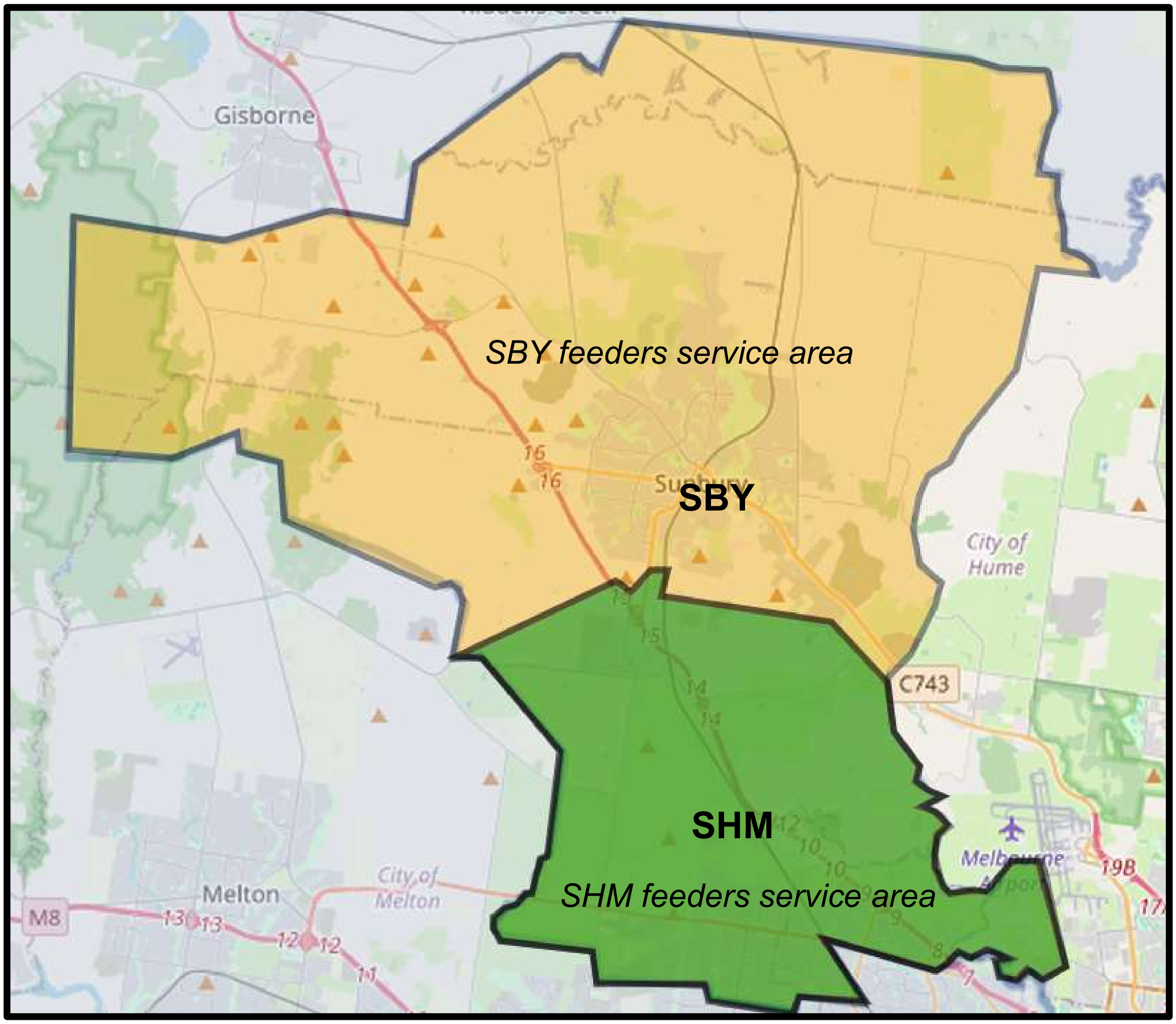
# 3. Identified need

## 3.1 Description of the identified need

Sunbury (**SBY**) zone substation and Sydenham (**SHM**) are owned and operated by JEN, providing power to approximately 38,223 JEN customers in Melbourne's outer northwest. SBY and SHM service a diverse mix of rural, developed urbanised, and greenfield residential and commercial growth areas across Sunbury, Gisborne South, Clarkefield, Diggers Rest, Wildwood, Plumpton, Fraser Rise, Bonnie Brook, Hillside, Bulla, Sydenham, Calder Park and Taylors Lakes.

Figure 3–1 shows the geographic supply area of SBY and SHM feeders.

**Figure 3–1: Sunbury supply area**




SBY and SHM are the main sources of electricity supply to the Sunbury/Diggers Rest Growth Corridor[5] of Melbourne, an area experiencing rapid development and increasing demand. Both zone substations are currently operating at high utilisation levels, with forecasts indicating continued pressure on capacity. The available

[5] Victorian Planning Authority – The Sunbury/Digger Rest Growth Corridor Plan.

transformation capacity provided by both SBY and SHM zone substations to service the area is declining over time. As such, the high growth and high asset utilisation will have increasing consequences for the reliability of electricity supply to JEN's customers within the Sunbury and Sydenham supply area.

Therefore, the identified need for this RIT-D is to maintain the reliability of supply in the Sunbury and Sydenham supply area whilst accommodating new customer connections, and growth in customer maximum demand. We provide the details below.

JEN has prepared this options screening report to assess whether the reliability needs of the Sunbury and Sydenham supply area could be met either fully, or in part through non-network or SAPS options, and to consult stakeholders on the credible options we have considered to address the identified need.

## 3.2 Assumptions used in identifying the identified need

JEN's planning standard for reliability of supply is based on a probabilistic planning approach which estimates the Expected Unserved Energy (**EUE**) in megawatt hours (MWh) per annum of customer supply interruptions. The EUE is expressed financially by multiplying it with a Value of Customer Reliability (**VCR**) ($/MWh). JEN uses this approach to identify, quantify and prioritise investment in the distribution network. Typically, the EUE is calculated through understanding the load-at-risk for each network asset with an identified capacity limitation. This is normally calculated through modelling load-at-risk under system normal, and if any single item of equipment is out of service (called a normal minus one or N-1 scenario, i.e., a contingency condition), taking into account the probability of an asset failure and its restoration times. The value of the EUE will depend on the topology and capacity of the existing network and the forecast demand. For the Sunbury and Sydenham supply area, this is presented below in Sections 3.2.1 and 3.2.2.

### 3.2.1 Network capacity

The existing 22 kV buses of both SBY and SHM are not fully utilised. This means that they can support additional feeders to meet the increasing demand within the Sunbury and Sydenham supply area. However, the 66/22 kV power transformer and transformer 22kV circuit breaker thermal limits are limiting the summer and winter capacity at SBY and SHM. We expect the situation to worsen as a result of forecast increased demand.

SBY consists of one 66/22 kV 20/33 MVA power transformer (No.2), two 66/22 kV 10/16 MVA power transformers (No.1 and No.3) and 7 x 22 kV feeders from three 22 kV indoor bus switchboards. The total system normal (N) secure rating of the zone substation is 65 MVA. The single contingency (N-1) rating is based on the transformer cyclic ratings, assuming one transformer is out of service. This gives an N-1 rating of 38 MVA (summer) and 39.6 MVA (winter).

SHM consists of two 66/22 kV 20/33 MVA power transformers, and 6 x 22 kV feeders from three 22 kV indoor bus switchboards. The total system normal (N) secure rating of the zone substation is 66 MVA. The single contingency (N-1) rating is based on the transformer cyclic ratings, assuming one transformer is out of service. This gives an N-1 rating of 38 MVA (summer) and 39.6 MVA (winter).

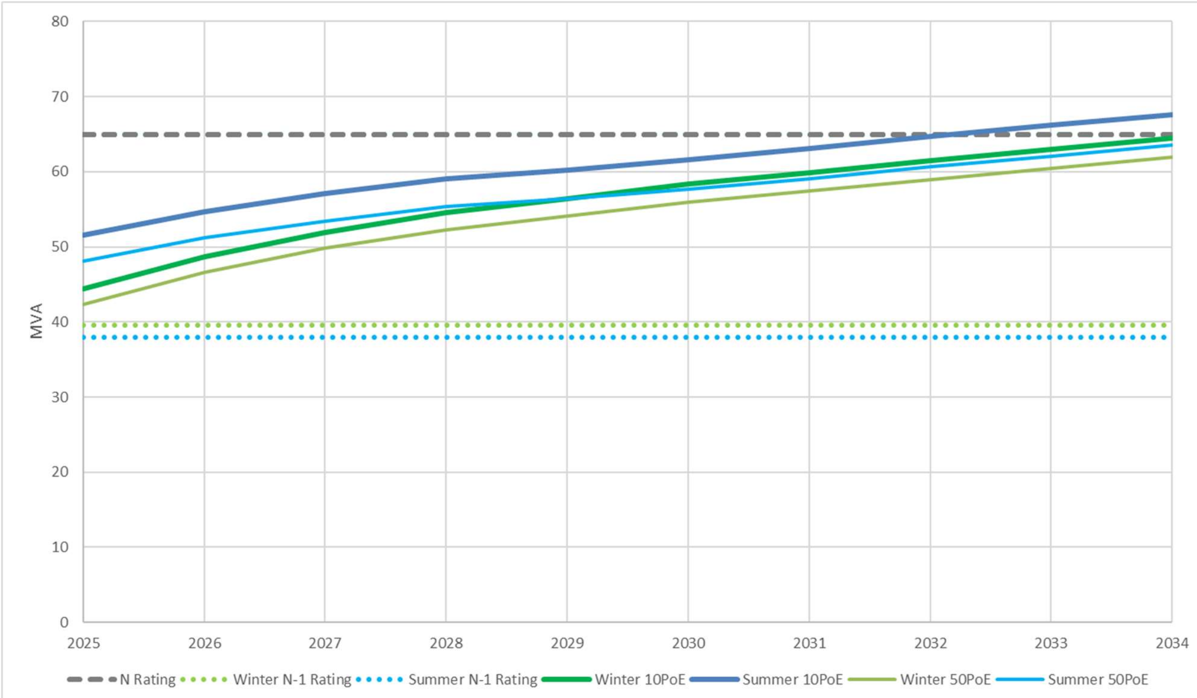
The load transfer capacities away from SBY and SHM are currently 5.7 MVA and 2.7 MVA, respectively, however with the high growth in the area, this level is expected to deteriorate by approximately 1 MVA per annum.

### 3.2.2 Maximum demand forecasts

The maximum demand forecasts for SBY are shown in Figure 3–2. Maximum demand is forecast to increase over the next several years, primarily driven residential customer connections associated with subdivision developments in the southwestern and northeastern part of the Sunbury supply area .

SBY is a summer peaking zone substation. The SBY maximum demand (prior to load transfers) is forecast to be 51.5 MVA for the summer of 2025 under a 10% Probability of Exceedance (**POE**). By 2034 it is forecast that maximum demand will rise to approximately 67.6 MVA.

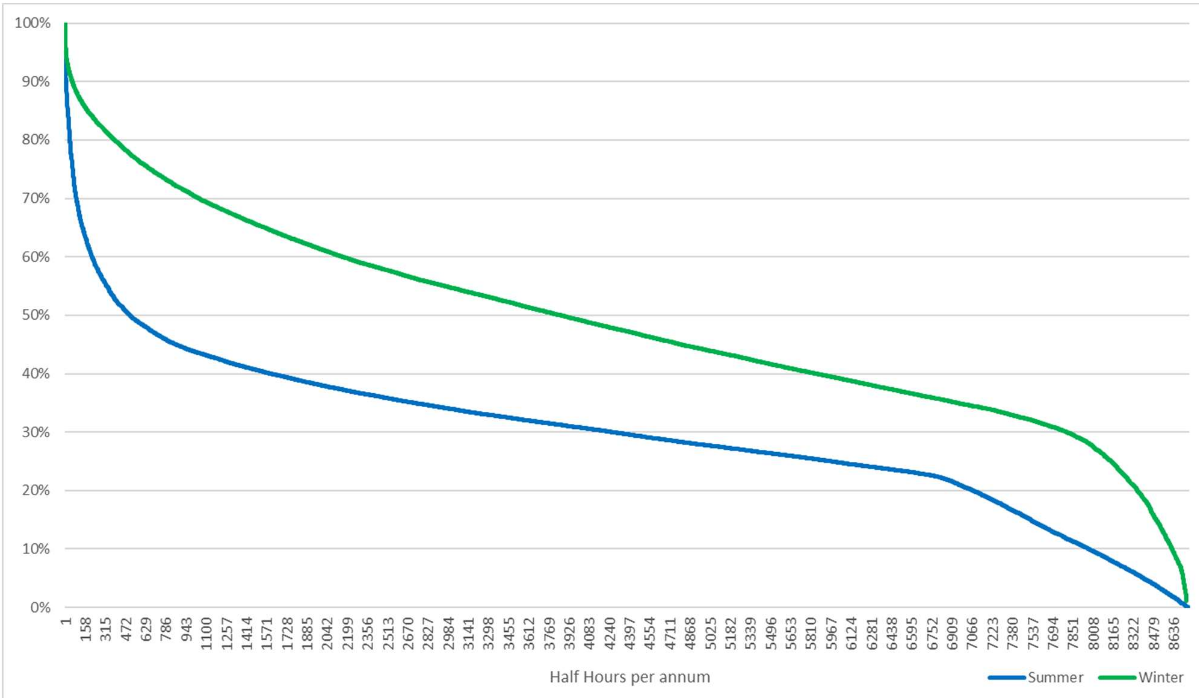
**Figure 3–2: SBY maximum demand forecast and ratings (MVA)**




SBY is expected to exceed its N rating by 2033 under a 10% PoE summer maximum demand scenario, and 2028 under a 50% PoE winter maximum demand scenario. The N rating is also expected to be exceeded in summer from 2032. Additionally, SBY is already exceeding its N-1 rating for both 10% PoE and 50% POE maximum demand scenarios in summer and winter.

The duration of the demand experienced at SBY is illustrated in Figure 3–3 with a summer load factor of 0.30 and a winter load factor of 0.49.

**Figure 3–3: SBY load-duration curve (% of summer and winter maximum demand)**




At SBY, the share of the maximum demand from a total of 18,875 customers (forecast to be consuming up to 51.5 MVA of coincident net load in summer 2025 with 134 GWh of net annual energy consumption), comprises of:

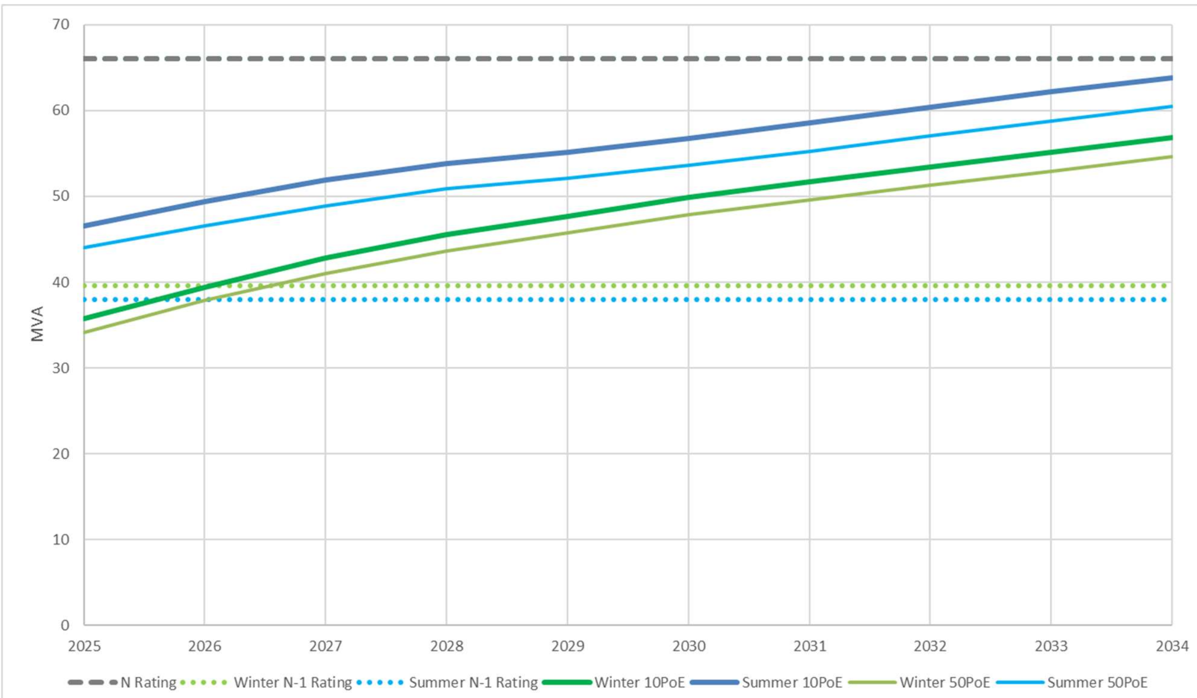
- 17,791 residential customers consuming 41.8 MVA peak summer load (average 0.002 MVA per customer) and 60.1% of the annual energy consumption.
- 1,051 commercial customers consuming 9.5 MVA of peak summer load (average 0.009 MVA per customer) and 39.2% of the annual energy consumption.
- 33 industrial customers consuming 0.2 MVA of peak summer load (average of 0.006 MVA per customer) and 0.7% of the annual energy consumption.

Currently there is no HV-connected embedded generation supplied from SBY zone substation other than the small LV-connected residential and commercial solar PV. In the SBY area, there are approximately 5,400 solar PV installations with a combined capacity of 27 MW, representing a customer penetration rate of 29%.

The maximum demand forecasts for the SHM area are shown in Figure 3–4. The maximum demand is also forecast to increase over the next several years as a result of residential customer connections associated with subdivision developments in the western and northwestern part of the Sydenham supply area .

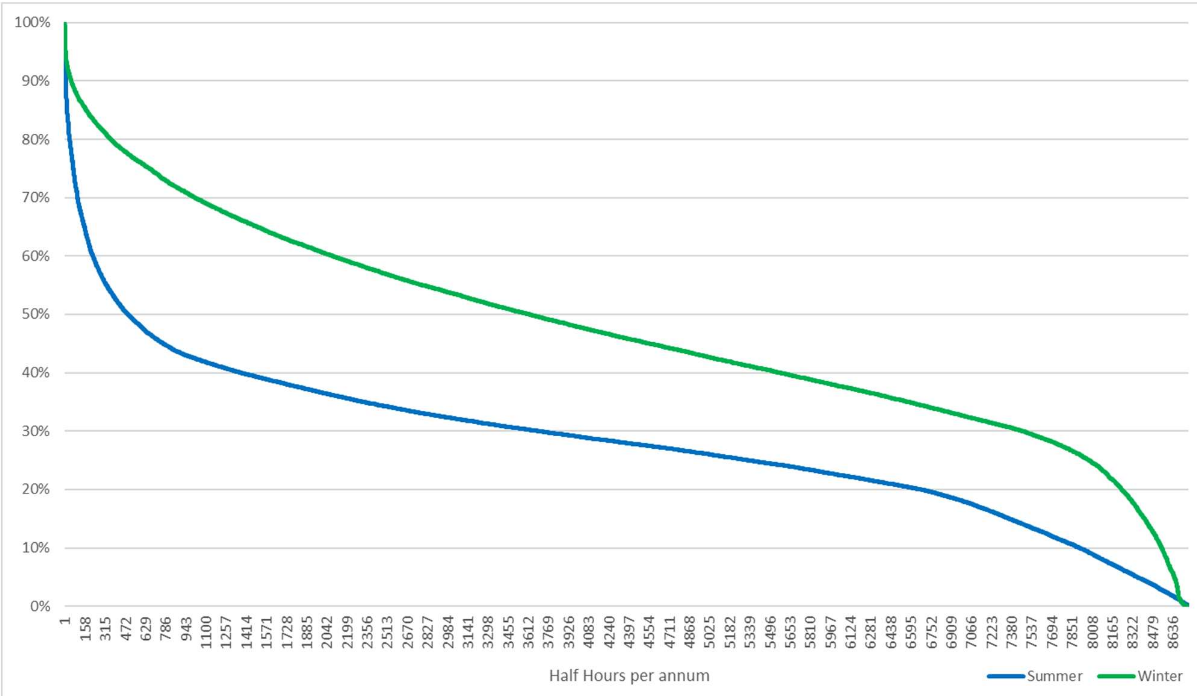
SHM is a summer peaking zone substation. The SHM maximum demand (prior to load transfers) is forecast to be 46.6 MVA for the summer of 2025 under a 10% Probability of Exceedance (**POE**). By 2034 it is forecast that maximum demand will rise to approximately 63.8 MVA.

**Figure 3–4: SHM maximum demand forecast and ratings (MVA)**




The duration of the demand experienced is illustrated in Figure 3–5 with a summer load factor of 0.28 and a winter load factor of 0.47.

Figure 3–5: SHM load-duration curve (% of summer and winter maximum demand)




At SHM, the share of the maximum demand from a total of 19,348 customers (forecast to be consuming up to 46.6 MVA of coincident net load in winter 2025 with 116 GWh of net annual energy consumption), comprises of:

- 18,876 residential customers consuming 40.6 MVA peak winter load (average 0.002 MVA per customer) and 67.5% of the annual energy consumption.
- 450 commercial customers consuming 0.7 MVA of peak winter load (average 0.012 MVA per customer) and 30.2% of the annual energy consumption.
- 22 industrial customers consuming 5.3 MVA of peak winter load (average of 0.032 MVA per customer) and 2.3% of the annual energy consumption.

Currently there is no HV-connected embedded generation supplied from SHM zone substation other than the small LV-connected residential and commercial solar PV. At the SHM area, there are approximately 5,600 solar PV installations with a combined capacity of 28 MW, representing a customer penetration rate of 29%.

## 3.3 Credible solution requirements to address the identified need

JEN's forecasts indicate that the existing assets at SBY and SHM will be insufficient to meet projected maximum demand under single contingency (**N-1**) conditions, where one network asset is out of service due to either a forced or planned outage. This is expected to result in a significant deterioration in supply reliability for customers within the Sunbury and Sydenham supply area under system normal and single contingency conditions. The situation is further compounded by the deteriorating transfer capacity between the SBY and SHM zone substations, as the spare capacity of the 22 kV distribution feeder ties continues to erode due to growing maximum demand.

A credible solution to the identified need should seek to maintain levels of supply reliability for customers within the Sunbury and Sydenham supply area. The solution should deliver sufficient capacity to reliably supply the demand within the supply area throughout the year, taking into account the forecast demand, available network capacity (under system normal and single contingency conditions) and load transfer capacity. The annualised cost of a credible option must be lower than the value of the EUE for which it is intending to displace. JEN consider this could be achieved through a range of solutions, including one or a combination of the following:

- Non-network or SAPS option
- Upgrade existing transformers (No.1 and No.3) at SBY zone substation and one new 22 kV feeder to offload SHM zone substation.
- Install a third transformer at SHM zone substation, and one new 22kV feeder to offload SBY zone substation.
- New 66/22 kV 2 x 20/33 MVA Plumpton (**PLN**) zone substation with two new 22 kV feeders.

The minimum level of network support required for the underlying growth in customer maximum demand for the Sunbury and Sydenham supply area is up to 33 MW over the 10-year period. Smaller (or staged) solutions of at least 11MW in the first year with 2 MW (per annum cumulative) up to 33MW, could provide sufficient capacity to address the identified need.

# 4. Network options

JEN has identified four credible network options (in addition to the base case) to address the identified need:

- Option 1 - Base case “Do nothing”, i.e., shed customer load when the network is overloaded.
- Option 2 - Upgrade existing transformers (No.1) at SBY and one new 22 kV feeder to offload SHM.
- Option 3 - Upgrade existing transformers (No.1 and No.3) at SBY and one new 22 kV feeder to offload SHM.
- Option 4 - Install a third transformer at SHM, and two new 22kV feeders to offload SBY.
- Option 5 - New 66/22 kV 2 x 20/33 MVA Plumpton (PLN) zone substation with two new 22 kV feeders.

## 4.1 Option 1 - Do nothing (base case)

Option 1 involves maintaining the current operating regime. The capital cost of this option is assumed to be zero, with the cost of unplanned outages due to network asset overload represented by the value of EUE.

## 4.2 Option 2 - Upgrade existing transformers (No.1) at SBY and one new 22 kV feeder to offload SHM

Option 2 involves upgrading existing 66/22 kV 10/16 MVA transformer No.1 at SBY zone substation and establishing one new 22kV feeder from SBY to SHM supply area (approximately 4.5 km in length) to offload SHM zone substation.

This option is expected to deliver a lower value of EUE compared to Option 1 as it is developed to partially address the identified need.

The capital cost of Option 2 is approximately $14.35 million (real $2025) including:

- $6.99 million (real $2025) for upgrading existing SBY transformer No.1
- $7.36 million (real $2025) for a 4.5 km of new feeder from SBY to SHM to offload SHM zone substation.

## 4.3 Option 3 - Upgrade existing transformers (No.1 and No.3) at SBY and one new 22 kV feeders to offload SHM – the preferred network option

Option 3 involves upgrading both existing 66/22 kV 10/16 MVA transformer No.1 and No.3 at SBY zone substation and establishing one new 22kV feeder from SBY to SHM supply area (approximately 4.5 km in length) to offload SHM zone substation.

This option is expected to deliver a lower value of EUE compared to Option 1 as it is developed to address the identified need in its entirety.

The capital cost of Option 3 is approximately $21.34 million (real $2025) including:

- $13.98 million (real $2025) for upgrading existing SBY transformer No.1 and No.3
- $7.36 million (real $2025) for a 4.5 km of new feeder from SBY to SHM to offload SHM zone substation.

## 4.4 Option 4 - Install a third transformer at SHM, and one new 22kV feeder to offload SBY

Option 4 involves establishing a new 66/22 kV 20/33 MVA Transformer including third 22kV switchgear at SHM zone substation and establishing one new 22kV feeder from SHM to SBY supply area (approximately 4.5 km in length) to offload SBY zone substation.

This option is expected to deliver a lower value of EUE compared to Option 1 as it is developed to address the identified need.

The capital cost of Option 4 is approximately $23.75 million (real $2025) including:

- $16.38 million (real $2025) for establishing the third transformer and 22kV switch gear at SHM including rearrangement of existing network assets to make space for the new assets.
- $7.36 million (real $2025) for a 4.5 km of new feeder from SBY to SHM to offload SBY zone substation.

## 4.5 Option 5 - New 66/22 kV 2 x 20/33 MVA Plumpton (PLN) zone substation with two new 22 kV feeders

Option 5 involves establishing a new 66/22 kV 2 x 20/33 MVA Plumpton (PLN) zone substation with 2 new 22 kV feeders at a site yet to be procured in Plumpton and extending two 66 kV lines from existing KTS-SBY No.2 66kV line (approximately 3 km in total).

This option is expected to deliver a lower value of EUE compared to Option 1 as it is developed to address the identified need.

The capital cost of Option 3 is approximately $54.67 million (real $2025) including:

- $35.23 million (real $2025) for establishment of PLN
- $2.87 million (real $2025) for 3 km extension of the 66kV sub-transmission network to the zone substation
- $11.45 million (real $2025) for total 7 km of two new feeders from PLN, to offload SBY and SHM zone substations
- $5.12 million (real $2025) for the costs of PLN land procurement, services and access.

## 4.6 Potential deferred augmentation charge

For all network options that are expected to fully address the identified need, Option 3 has the lowest investment costs. Option 3 is the preferred network option with an in-service timing expected by 2027/28.

Based on the total capital cost of Option 3, a regulatory rate of return, and annual operational costs, the deferral saving is approximately:

- $1.10 million[6] per annum (real $2025) for the upgrading of two transformers at SBY.

This assumes the same reliability outcomes are maintained as with the preferred network option. This serves as a guide for non-network or SAPS providers to determine the financial viability of their proposal.

[6] (21.34) x (5.18%) = $1.10 million.

# 5. Non-network and SAPS options

Potential non-network and SAPS options that could meet the investment objectives (as envisaged in the Application Guidelines Section 6.1) are listed below:

- **Demand Management** - Any measure or program targeted at reducing peak demand, including direct load control, broad-based demand management, or targeted customer demand response programs; and/or
- **Embedded Generation** - Increased local or distributed generation/supply options, including using capacity for standby power from existing or new embedded generators, or using energy storage systems and load transfer capacity.

## 5.1 Non-network and SAPS options assessment scenarios

The purpose of defining potential non-network and SAPS scenarios is to evaluate whether these options – individually or combined- offer a viable and efficient alternative to network investment in addressing the identified need. A non-network or SAPS option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g., generation plus demand management).

The potential non-network and SAPS scenario for the Sunbury and Sydenham supply areas aims to fully—or at least comparably—address the identified need relative to network alternatives. This would involve mitigating the EUE risk specifically for the load within the 22 kV or LV distribution networks of these areas. The minimum level of non-network network support required for the underlying growth in customer maximum demand for the supply area is up to 33 MW over the 10-year period. Smaller (or staged) solutions of at least 11MW in the first year with 2 MW (per annum cumulative) up to 33MW,could provide sufficient capacity to address this part of the identified need. No other scenarios have been identified.

Viable generation, storage or load reduction options that can support any network capacity shortfalls in meeting the forecast demand of the general load within the Sunbury and Sydenham supply area during the 10-year planning horizon, would require a level of support of up to 33 MW from an initial level of 11 MW which could comprise of:

- 7 MW and 4 MW of generation initially at both SBY and SHM, then 2 MW of generation per annum over 7 years; or
- 33 MW of generation initially.

Note that the maximum viable generator size per distribution feeder is no more than 14.2 MW, based on the ability of JEN's 22 kV network to connect the generation, and the need to provide a level of generation redundancy.

Support would be required under single contingency (N-1) conditions for the following network assets, which have identified capacity limitations during periods when the demand exceeds their ratings:

- SBY No.1, No.2 or No.3 transformers; or
- SHM No.1, or No.2 transformers

Providing support for these assets would enable them to meet the forecast maximum demand during contingency situations or events.

The maximum demands of individual customers indicate that no potential existing customer-owned generation would be large enough to meet the need, hence the generation would likely be a majority of new grid-connected systems. Adding storage, demand management or efficiency measures to the non-network option would reduce the generation requirements stated above.

The costs of this scenario could be comparable to the costs of the preferred network option detailed in Section 4.3 but could improve in competitiveness if value-stacked with market-based revenues. For example, the installed cost of small gas-fired generator is approximately $1.25 million (real $2025) per MW[7]. For 33 MW of generation, the cost will be over $41.3 million (real $2025), once land, operating and other establishment costs are included.

Based on the preliminary assessment, a non-network option to address network capacity shortfalls and meet the forecast demand of general load within the Sunbury and Sydenham supply areas may be a credible option.

## 5.2 Non-network and SAPS options assessment criteria

This section reports on the credibility of potential non-network and SAPS options as alternatives or supplements for the preferred network option.

The decision criteria used by JEN to assess the potential credibility of non-network and SAPS options included: :

- **Addresses the identified need**: reduce or eliminates the supply reliability risks associated with the identified need.
- **Technically feasible**: there are no technical constraints or barriers that prevent an option from being delivered to address the identified need.
- **Economically feasible**: the economic viability is commensurate or better than the preferred network option.
- **Timely**: can be delivered in a timescale that is consistent with the timing of the identified need.

Table 5–1 shows the rating scale applied for assessing non-network options.

**Table 5–1: Assessment criteria rating**

| Rating | Colour Coding |
|---|---|
| Does not meet the criterion | Red |
| Does not fully meet the criterion (or uncertain) | Amber |
| Clearly meets the criterion | Green |

The assessment has also considered whether a non-network or SAPS option (or combination of non-network measures) is a viable way to avoid or reduce the scale of network investments in a way that meets the identified need. A non-network option may comprise a single non-network measure (e.g. installation of renewable or embedded energy generation) or a combination of measures (e.g. generation plus demand management).

[7] 2020 Costs and Technical Parameter Review – Consultation Report for AEMO - Aurecon

Table 5–2 shows the initial assessment of non-network and SAPS options against the RIT-D criteria. The assessment identified that some of potential non-network or SAPS options investigated (or a combination of options) are credible options that could adequately meet the identified need. The assessment commentary for each of the generation, demand response and storage options are set out in the following sections.

Hence, consistent with NER clause 5.17.4(b), JEN has published this options screening report as part of the first phase of consultation under the RIT-D.

**Table 5–2: Assessment of non-network options against RIT-D criteria**

| Options | Assessment against criteria | | | |
|---|---|---|---|---|
| | Meets Need | Technical | Economic | Timing |
| **1.0 Generation and Storage** | | | | |
| 1.1 Generation using gas turbines or diesel | | | | |
| 1.2 Generation using grid-scale solar and storage | | | | |
| 1.3 Standby generation (existing large customer) | | | | |
| 1.4 Storage only using grid-scale batteries | | | | |
| **2.0 Demand Management** | | | | |
| 2.1 Customer power factor correction | | | | |
| 2.2 Customer solar power and storage systems | | | | |
| 2.3 Broad-based demand response | | | | |
| 2.4 Targeted demand response | | | | |

## 5.3 Non-network and SAPS options assessment commentary

### 5.3.1 Generation and storage

The assessment rationale for each of the generation and storage options is as follows, with their potential ability to meet the assessment criteria:

- **Generation using gas turbines or diesel (1.1):**

*Identified need (met)* - Capable of meeting the identified need through provision of multiple gas turbine or diesel generators.

*Technical (met)* - Significant constraints and barriers to deployment of multi-megawatt generation equipment in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land that could form suitable sites for generation. There appears to be a high-pressure gas pipeline in the locality to the east of the Hume Highway as a potential fuel source.

*Economic (met)* - Costs of this type of generation appear comparable to the network alternatives excluding land, grid connection and operating costs. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated (and other services) through the market. The scale of estimated costs and the potential revenue streams illustrate the potential for an economically viable non-network and/or SAPS solution.

*Timing (met)* - Planning processes and the nature of the investment with likely noise and environmental objections, together with design requirements (both for the generators, gas connections and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

*Overall* – Generation using gas turbines or diesel (or other similar technology) is a potentially credible option.

- **Generation using grid-scale solar and storage (1.2):**

*Identified need (partially met)* - Capable of meeting identified need partially through provision of solar farms and/or additional rooftop solar, coupled with grid-connected batteries.

*Technical (partially met)* - Significant constraints and barriers to deployment of multi-megawatt generation equipment in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land that could form suitable sites for generation and storage. Energy and reliability requirements may be difficult to meet using solar generation alone without oversizing the batteries.

*Economic (met)* - Costs of this type of generation appear comparable to the network alternatives excluding land, grid connection and operating costs. In addition to network support payments, the proponent could aim to recoup these costs through selling power generated/stored (and other services) through the market. The scale of estimated costs and the potential revenue streams illustrate the potential for an economically viable non-network and/or SAPS solution.

*Timing (met)* - Planning processes for zoning, together with design requirements (both for the generation and storage and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

*Overall* – Generation using grid connected solar and battery storage (or other similar technology) is a potentially credible option.

- **Standby generation (large customer) (1.3)**

*Identified need (partially met)* - As noted in section 3.2.2, the numbers of industrial and commercial customers are consuming relatively small proportions of SBY and SHM's maximum demand and annual energy in aggregate. It is likely that a number of those customers may be prepared to install or use their existing standby generation to operate disconnected from the grid in the event of a network limitation. The new major customers may also be open to negotiations at their own site.

*Technical (partially met)* - This type of standby generation model may be technically feasible depending on customer interest to install standby generation, or to utilise their existing standby generation. To meet the need, the solution would need to be operated as an aggregated portfolio.

*Economic (partially met)* - The economic viability of this model is dependent on the customer uptake and the load of those customers wishing to participate. Smaller load customers will require more installations for the same delivered response and the size of the customer standby generation is limited to the customer's maximum demand.

*Timing (met)* – Customer recruitment and installation of standby generation could be a multi-year process but may be completed within the timeframe of the preferred network option.

*Overall* – Standby generation at customer premises is a potentially credible option.

- **Storage only using grid-scale batteries (1.4)**

*Identified need (partially met)* - Capable of meeting identified need through provision of grid-connected batteries.

*Technical (partially met)* - Significant constraints and barriers to deployment of multi-megawatt batteries in a developing urban environment (e.g. obtaining planning permits, local community objections, adequately managing the environmental impacts). However, there are vast areas of undeveloped land that could form suitable sites for storage. Energy requirements may be difficult to meet using storage alone without oversizing the batteries.

*Economic (partially met)* - Costs of this type of solution using only batteries is likely to be more expensive than the network alternatives (even if land, grid connection and operating costs were excluded). In addition to network support payments, the proponent could aim to recoup these costs through selling power generated/stored (and other services) through the market. However, the scale of estimated costs and the potential revenue streams illustrate the potential for an economically viable non-network and/or SAPS solution is not as strong as a solution coupled with generation.

*Timing (met)* - Planning processes for zoning, together with design requirements (for storage and any required 22 kV connections), is a multi-year process, but may be completed within the timeframe of the preferred network option.

*Overall* – Generation using grid connected battery storage (or other similar technology) is a potentially credible option.

### 5.3.2 Demand management

The assessment rationale for the demand management/efficiency options is as follows, with their potential ability to meet the assessment criteria:

- **Customer power factor correction (2.1)**

*Identified need (not met)* - This option cannot address the identified need because both SBY and SHM operate close to unity power factor, even during periods of maximum demand. As a result, additional reactive power compensation would not reduce demand or alleviate capacity constraints.

*Technical (met)* - This type of solution is technically feasible for industrial users on a certain type of contract and is achievable.

*Economic (met)* - This solution could be cost-effective on parts of the network with low power factor.

*Timing (met)* - This option could be completed within the timeframe of the preferred network option.

*Overall* – Power factor correction is not a potentially credible option, as the power factor is already fully corrected for the supply area.

- **Customer solar power and storage systems (2.2)**

*Identified need (partially met)* - As noted in section 3.2.2, solar PV penetration across customer premises in the Sunbury and Sydenham supply area is not yet fully saturated, indicating significant potential for further installations on residential, commercial and industrial properties. The key challenge is to pair storage with solar PV systems to help offset the capacity shortfall during peak demand periods. Storage behind the meter uptake is currently very low, however opportunities are potentially going to emerge with the use of electric vehicle storage to provide network support.

*Technical (met)* - This option is technically feasible as the appetite for customers to take up solar PV is high and the opportunity for customers to take up electric vehicles and behind the meter storage is emerging with aggregator functions starting to develop in the market.

*Economic (met)* - Achieving a greater than average solar PV and storage take up with some level of control for network support would require a financial incentive.

*Timing (met)* - This option could be completed within the timeframe of the preferred network option.

*Overall* - Customer solar power and storage systems is a potentially credible option to be used for network support purposes in aggregate.

- **Broad-based demand response (2.3)**

*Identified need (partially met)* – To implement a broad-based demand response program across the supply area, JEN would need to engage individual customers to participate in a managed initiative/program aimed at reducing consumption. There are a relatively small number of commercial and industrial customers in the supply area that could contribute meaningfully to demand reduction. However, demand response could be expanded to cover residential customers, enabling some level of control over air-conditioning usage during peak periods, supported by financial incentives.

*Technical (partially met)* - This option may be technically feasible but could struggle to meet the required demand reduction in the later years of the forecast period, given a high level of customer participation would be needed. However, it may be more feasible or practical as short-term solution, potentially deferring the need for network investment during the initial years.

*Economic (partially met)* - It is unclear whether this option is economically feasible, as it depends on customer willingness to participate and the level of financial incentives needed to achieve the required demand reductions. Nevertheless, there have been examples where broad-based demand response programs have proven to be possible.

*Timing (met)* - This option could be completed within the timeframe of the preferred network option.

*Overall* – Broad based demand response is a potentially credible option, particularly in the initial years of the 10-year period.

- **Targeted demand response (2.4)**

*Identified need (partially met)* – To implement a targeted demand response program across the network constrained assets only, each of JEN's customers in these specific areas would need to be approached to participated in a managed program to reduce consumption. There are a relatively large number of commercial and industrial customers in the supply area that could be well equipped to provide such a service to reduce their demand, and the demand response could be expanded to cover residential demand on those capacity constrained feeders only to allow some level of control over air-conditioning demand at times of peak, both using financial incentives program.

*Technical (partially met) -* This option may be technically feasible but could struggle to meet the demand reduction needs in the later part of the forecast period given a high participation rate would be needed. Instead, it is probably more feasible for this option to be able to defer implementation of the network option in the initial years.

*Economic (met)* – It is more likely this option will be economically feasible as the demand response is targeted to those areas of the supply area that have a network limitation. Success of the program will depend on the customers willingness to participate, and the size of the incentives needed to active the demand reductions needed. Nevertheless, there have been examples where targeted demand response programs have proved to be possible.

*Timing (met) -* This option could be completed within the timeframe of the preferred network option.

*Overall* – Targeted demand response is a potentially credible option, particularly in the initial years of the 10-year period.

# 6. Conclusion and next steps

## 6.1 Conclusion

The analysis outlined in section 5 highlights the potential for non-network or SAPS solutions, or combinations of non-network and network options, to adequately meet the criteria outlined in this report.

This options screening report demonstrates that a non-network or SAPS solution could be technically and economically feasible in addressing the identified need within the Sunbury and Sydenham supply areas.

## 6.2 Next steps

We are interested in exploring all potential non-network solutions with proponents. We recognise that some proponents may require information in addition to that provided in this report. If you need further information, please contact us as early as possible, to give us sufficient time to assess any proposed feasible network and non-network potential solutions. It should be noted that parts of the network exhibit volatile load growth which is usually driven by economic and demographic factors that are difficult to foresee and model. It is essential that proponent present alternatives to network solutions with sufficient lead time to enable thorough evaluation, planning and implementation.

We invite written submissions on this options screening report from registered participants, AEMO and interested parties, including pricing proposals from prospective non-network and SAPS providers detailing alternative solutions and demonstrating how the solutions achieve the assessment criteria presented in this report. All pricing proposals should include sufficient technical and financial information to enable JEN to undertake a comparative analysis of the proposed solutions against alternative options.

A period of three months shall be made available for preparation of submissions and proposals. At the end of this period, JEN will assess all options we consider to be credible against the network options.

All submissions, and enquiries must be identified as “Sunbury and Sydenham Supply Area RIT-D” and should be directed to: PlanningRequest@jemena.com.au

Submissions must be lodged with us on or before 3 November 2025.

All submissions will be published on JEN’s website. If you do not wish to have your submission published, please indicate this clearly in your submission.

As the total cost of the most expensive credible network option to address the identified need is greater than the trigger threshold of $14 million[8] for the publication of and consultation on a Draft Project Assessment Report (DPAR), we intend to prepare and publish a DPAR. The DPAR will present a detailed assessment of all credible network, non-network and SAPS options that address the identified need, applying the latest available information on demand forecasts, VCR estimates and project cost estimates. The DPAR will identify the proposed preferred option. Further consultation, in accordance with the RIT-D process set out in the Rules, will then proceed.

[8] Source: AER 2024 RIT and APR cost thresholds review (November 2024).

# 7. Appendix A – Checklist of compliance clauses

Table 7–1 presents a checklist of the NER clause 5.17.4(e) and references the section within this options screening report where those clauses are addressed.

**Table 7–1: Compliance clauses checklist**

| Clause | Section |
|---|---|
| (1) a description of the identified need; | 3.1 |
| (2) the assumptions used in identifying the identified need; | 3.2 |
| (3) if available, the relevant annual deferred augmentation charge associated with the identified need; | 4.6 |
| (4) the technical characteristics of the identified need that a non-network option or (in relation to a SAPS enabled network) a SAPS option would be required to deliver, such as:<br>(i) the size of load reduction or additional supply;<br>(ii) location;<br>(iii) contribution to power system security or reliability;<br>(iv) contribution to power system fault levels as determined under clause 4.6.1; and<br>(v) the operating profile; | 3.3 |
| (5) a summary of potential credible options to address the identified need, as identified by the RIT-D proponent, including network options, non-network options and (in relation to a SAPS enabled network) SAPS options; | 4 & 5 |
| (6) for each potential credible option, the RIT-D proponent must provide information, to the extent practicable, on:<br>(i) a technical definition or characteristics of the option;<br>(ii) the estimated construction timetable and commissioning date (where relevant); and<br>(iii) the total indicative cost (including capital and operating costs); | 4 & 5 |
| (7) information to assist non-network providers wishing to present alternative potential credible options including details of how to submit a proposal for consideration by the RIT-D proponent. | 6 |