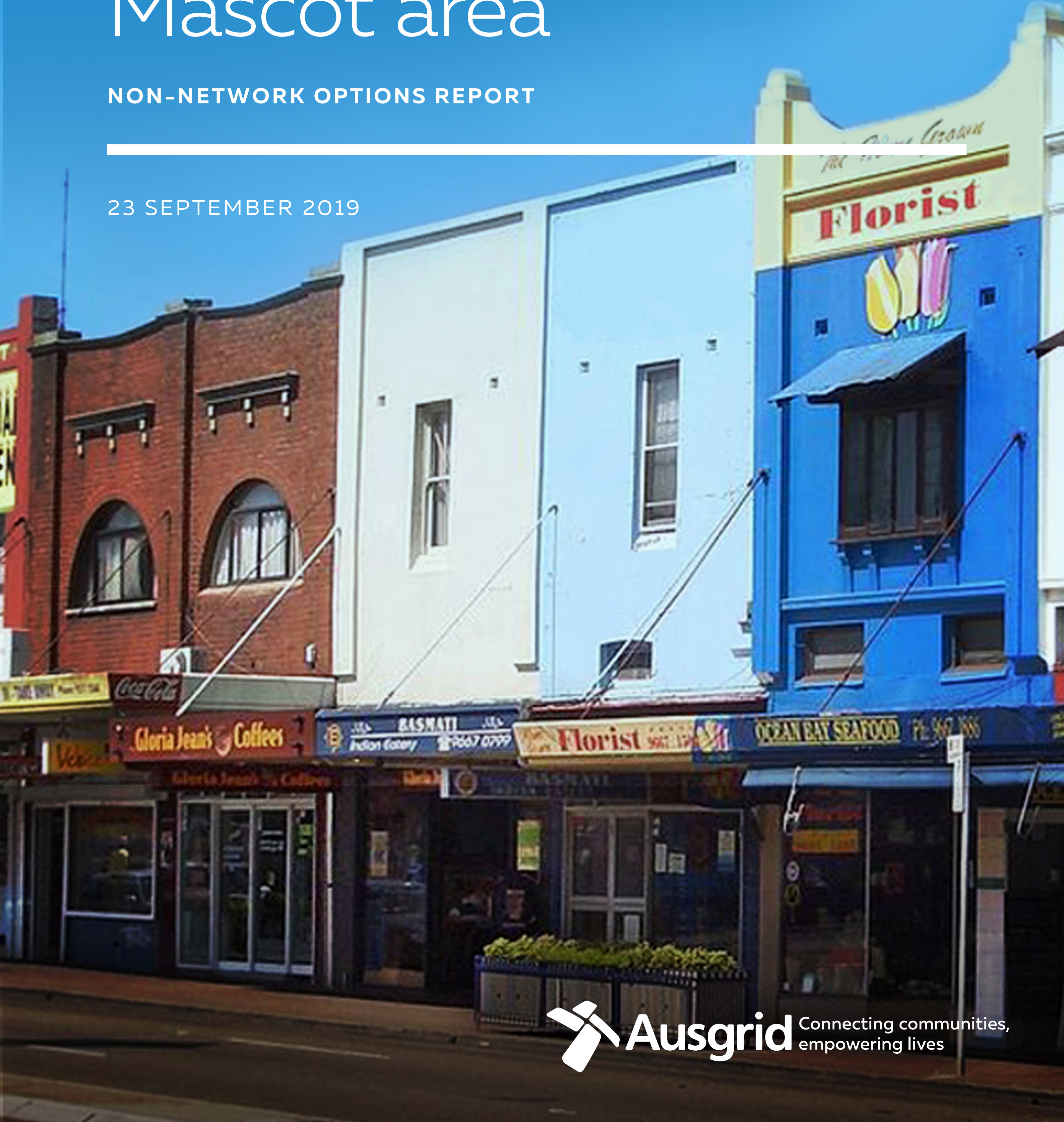
Addressing reliability requirements in the Mascot area

NON-NETWORK OPTIONS REPORT

23 SEPTEMBER 2019



Ausgrid Connecting communities, empowering lives

Addressing reliability requirements in the Mascot area

Non-network options Report – September 2019

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Executive Summary

Ausgrid has identified constraints in the Mascot area associated with aged asset issues at Mascot zone substation. Ausgrid has also identified demand management as being a potentially credible option as part of an integrated network and non-network solution mix to address the issues at Mascot.

Traditionally, demand management has not been considered feasible in being able to address aged asset issues, however, the recent rapid uptake of distributed energy resources such as rooftop solar PV and battery storage driven by falling prices and energy efficiency initiatives that offer permanent solutions to reduce customer electricity demand for a significant number of hours of the year means that Ausgrid is keen to explore the applicability of demand management to network needs driven by aged asset issues.

Based on cost benefit analysis, Ausgrid at this stage is targeting a 40% to 85% reduction in unserved energy risk in 2022/23 to enable deferral of the proposed supply solution by 1 to 3 years. The corresponding estimated funds available for effective DM solutions (real 18/19 dollars) are:

- For a 1 year deferral, DM funds available of $1.0m to 3.0m,
- For a 2 year deferral, DM funds available of $1.1m to 3.8m, and
- For a 3 year deferral, DM funds available of $1.6m to 4.0m.

The funds available as well as the duration and scale of demand reductions being sought is summarised in Table 6.4 below. Refer to section 6 for a full explanation of the demand management requirements.

Table 6.4 – Target area demand management requirements and available funds

To defer supply solution by:	DM req'd in:	DM funds[a] (present value $m)	Indicative demand management requirements[b]								
			Duration of permanent & temporary DM required over 408hr window (hours)			Volume of permanent & temporary DM required over 408hr window (MWh)			Peak reduction (MW)		
			2022/23	2023/24	2024/25	2022/23	2023/24	2024/25	2022/23	2023/24	2024/25
1 year	2022/23	1.0 to 3.0	125 to 150	-	-	170 to 275	-	-	3 to 5	-	-
2 years	2023/24	1.1 to 3.8	125 to 150	125 to 150	-	170 to 275	170 to 275	-	3 to 5	3 to 5	-
3 years	2024/25	1.6 to 4.0	125 to 150	125 to 150	125 to 150	170 to 275	170 to 275	170 to 275	3 to 5	3 to 5	3 to 5

If DM is found to be not feasible or cost-effective following a market engagement process, Ausgrid will proceed with the preferred supply side solution, which is the establishment of new 132/11kV zone substation on an alternative site in the Mascot area in 2022/23 for an estimated capital cost of $38 million (real 18/19 dollars).

To assist non-network proponents, we describe further in this document the technical characteristics of our network needs at Mascot zone substation, which is intended to guide non-network proponents in developing credible proposals for non-network options. Ausgrid welcomes an open dialogue with non-network proponents to identify potential alternatives to the network options identified in this paper. Ausgrid welcomes cost-effective partial solutions and we emphasize that individual proposals need not address the entire need.

Submissions should be lodged with us on or before **23 Dec 2019** (3 month consultation period)..

1 Introduction

1.1 Purpose

Ausgrid is the largest distributor in the National Electricity Market (NEM), connecting around 1.7 million industrial, business and residential customers. We operate in the NEM as both a Distribution Network Service Provider (DNSP) and a Transmission Network Service Provider (TNSP). Our network area is made up of large and small substations connected through high and low voltage powerlines, underground cables and power poles spread across more than 22,275 square kilometres. Our network extends from Waterfall in Sydney's south, to Auburn in inner western Sydney, to the Central Coast and Hunter Region.

Ausgrid's purpose is to connect communities and empower lives with a focus on affordability, reliability and sustainability. Non-network solutions have an important role to play in meeting these objectives.

This report is an initial step in our engagement with non-network proponents in addressing the identified need in relation to Mascot zone substation. Ausgrid welcomes an open dialogue with non-network proponents to ensure that the most technically and economically feasible solution is adopted, whether that solution is a network solution, a non-network solution or mix of both.

The engagement period for this Non-Network Options Report is three months from the publication date of this report, after which Ausgrid will proceed to prepare a more detailed Draft Project Assessment Report (DPAR). The DPAR will incorporate the latest available information on demand forecasts, VCR estimates, project cost estimates of the network and information about the proposals provided by non-network proponents in response to this Non-Network Options Report.

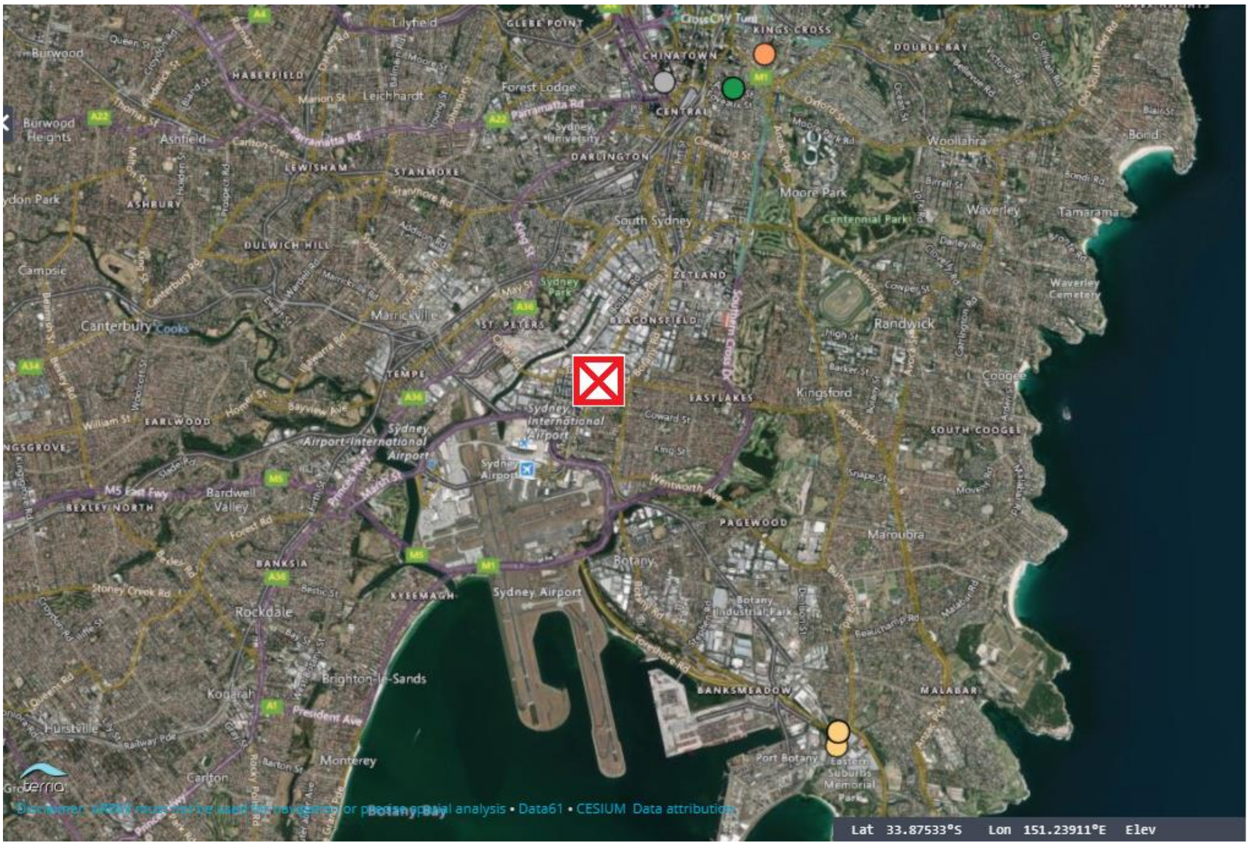
Due to the long timeframe required for consultation and to avoid delays in releasing information (this document) to the market, Ausgrid will develop in parallel a separate Request for Proposals (RFP) document that will formally request detailed submissions from the market via a formal procurement process. We have chosen not to combine an RFP document with this options report as we believe collaborative discussions with potential market providers following publication of this report would be a beneficial preliminary step prior to initiation of a formal tendering process.

Information on the next steps in the assessment process, how to make a submission and our contact details are provided in Section 7 of this report.

1.2 Mascot Zone Substation

Mascot 33/11kV zone substation is situated in the Eastern Suburbs of Sydney and was commissioned in 1946. It is supplied by six 33kV underground cables from Bunnerong North subtransmission substation which is around 8km away and consists of six 33/11kV transformers. Mascot provides supply to approximately 11,000 residential, commercial and industrial customers in the suburbs of Alexandria, Botany, Eastlakes, Mascot, Rosebery and St Peters. Figure 1.1 following shows the location of Mascot zone substation.

Figure 1.1: Mascot zone substation location



The identified need arises due to condition issues associated with the 11kV switchboards at Mascot zone substation.

Mascot zone contains different types of 11kV switchboards with different manufacturers and technologies, and condition issues have been identified for each of these. The air insulated switchgear and compound insulated switchgear, as well as the oil-filled circuit breakers, are nearing the end of their serviceable lives.

If left unaddressed, these assets are likely to become less reliable, which could expose Ausgrid's staff and the general public to increasing safety risks and also expose customers to increasingly frequent and prolonged supply interruptions. Due to the manner in which these assets are connected together, the failure of a single 11kV switchboard could, on average, result in the loss of electricity supply to around 20% of the Mascot zone substation load, equivalent to around 2,200 of Mascot's residential and business customers, for a duration ofseveral days..

This document presents an overview of aged asset issues at Mascot zone substation and associated 33kVfeeders, outlines possible options for economically mitigating overall supply risks, identifies the preferred network option to manage the risks into the future and invites non-network proponents to provide proposals that may be able to economically defer or remove the need for Ausgrid to invest in the preferred network option. At this early stage, the preferred network option is to establish a new 132/11kV zone substation on an alternative site, reconnect 11kV feeders to this site and decommission the existing Mascot 33/11kV zone substation at an estimated capital cost of $38 million.

1.3 Structure of this report

The remainder of this report is structured as follows:

- Section 2 provides background information on the network location and assets;
- Section 3 describes the need to be addressed;
- Section 4 describes the methodology and assumptions used in the assessment of the credible options;

- Section 5 describes in detail the credible network options and provides an indicative assessment of their respective augmentation costs;
- Section 6 describes the technical characteristics of the identified need, intended to guide non-network proponents in developing credible non-network options; and
- Section 7 provides details on how to make submissions and outlines next steps in the assessment process.

2 Background

This section provides an overview of the network supply arrangements relating to Mascot zone substation.

2.1 Network supply area

Mascot zone substation is presently supplied by six 33kV underground cables from Bunnerong North 132/33kV subtransmission substation. These six cables are directly connected to six 33/11kV transformers, which in turn are connected to six 11kV busbars. Mascot is configured such that one of the busbars is not loaded under normal conditions and provides a standby function for the other five busbars. These five busbars are loaded under normal operating conditions (these are referred to throughout this document as a “switchgear group”). A switchgear group is a collective term that encompasses the following items of substation equipment: a point of common connection (busbar) between the 33/11kV transformers and 11kV feeders, housing structure for multiple circuit breakers, individual 11kV circuit breakers, as well as associated control and protection equipment necessary to enable multiple 11kV feeders to supply customers in the surrounding area. A total of 28 outgoing 11kV feeders provide electrical supply via a dispersed 11kV network to the residential, commercial and industrial customers in the surrounding area after being transformed to low voltage at local distribution substations.

Mascot zone substation is equipped with different types of 11kV switchgear with different manufacturers and technologies. The compound insulated 11kV switchgear was installed when Mascot zone substation was commissioned and is currently over 70 years old. The air insulated 11kV switchgear is over 50 years old. The compound insulated switchgear house 11kV oil circuit breakers, which pose operational and safety risks.

The condition assessment, which included electrical tests undertaken by Ausgrid concluded that both the air insulated and compound insulated switchgear, as well as the oil circuit breakers, are nearing the end of their serviceable lives.

Although partial load can be transferred to the adjacent zone during the equipment failure period, not all the load served by the substation can be recovered under all possible outage conditions due to limitations within the 11kV network.

Note there is a committed project to transfer around 25MVA away from Mascot zone to nearby Green Square zone to mitigate the load at risk due to the aged asset issues at Mascot. All information in this report reflects the post transfer project condition and need.

More specifically, the main consideration driving the need to address the condition of the 11kV switchgear at Mascot zone substation is the amount of expected unserved energy (EUE) that would result from an electricity supply interruption involving one or more 11kV switchgear groups. While unlikely, such an event has a high impact and would, on average, result in a loss of supply to around 20% of the Mascot zone substation load, equivalent to around 2,200 residential, commercial and industrial customers.

Most of the EUE contribution comes from the compound-insulated switchgear groups at Mascot which in total contribute around 96% of the overall Mascot zone substation EUE.

The area supplied by these compound-insulated switchgear groups and adjacent parts of the network able to provide backup is therefore the **target area** from which Ausgrid is seeking demand reductions. See section 6 for a detailed description of the target area.

2.2 Overview of Ausgrid’s relevant statutory and regulatory obligations

2.2.1 National Electricity Rules (NER)

Under clause 5.17.1(b) of the NER, Regulatory Test for Distribution (RIT-D) proponents must apply the RIT-D to assess the economic efficiency of proposed network investments.

The RIT-D applies in circumstances where an identified need exists and the estimated capital cost of the most expensive potential credible option to address the identified need is more than $6 million. As part of the RIT-D process, distribution businesses must also consider non-network options when assessing credible options to address the identified need.

Under the RIT-D consultation procedures, distribution businesses are required to prepare and publish a Non-Network Options Report (NNOR). This report helps non-network proponents to identify potential non-network options and be better informed on the costs and market benefits associated with a potential option. These arrangements provide an opportunity for third parties to consider how they could address the distributor's identified need on the network.

This NNOR document sets out the requirements for the identified need at Mascot zone substation in accordance with clause 5.17.4(e) of the NER. In accordance with the requirements of the NER this report describes:

- the identified need in relation to the Mascot network;
- the assumptions used in identifying the identified need;
- the potential credible network options that may address this need; and
- the technical characteristics of a credible non-network option.

2.2.2 NSW Reliability and Performance Licence Conditions

All New South Wales electricity distribution businesses, including Ausgrid, are obliged to comply with reliability and performance standards as part of their distributor's licences[1]. These standards are determined by the New South Wales Government.

At a high-level, the reliability and performance standards are specified in terms of both:

- the average frequency of interruptions a customer may face each year; and
- the average time those outages last.

Specifically, under the current Ausgrid license, reliability and performance standards are expressed in two measures:

- the System Average Interruption Frequency Index – 'SAIFI' – which measures the number of times on average that customers have their electricity interrupted over a given period[2], and
- the System Average Interruption Duration Index – 'SAIDI' – which measures the total length of time (in minutes) that, on average, a customer would have their electricity supply interrupted over a given period[3].

These two reliability measures capture two key sources of inconvenience to electricity customers from supply disruptions, i.e. how long, on average, their electricity supply is off for as well as how often, on average, their electricity supply is off. Customers experience less inconvenience (i.e. a better level of supply reliability) the lower these measures are. Reliability standards applied to distribution networks typically set minimum requirements for each of these two measures.

The current reliability standards applying to the Mascot network area (classified as an 'urban' feeder type) are shown in the Table 2.1 following.

Table 2.1 – Current distribution reliability standards applying to Ausgrid[4]

Feeder type	Network Overall Reliability Standards		Individual Feeder Reliability Standard	
	SAIDI (Minutes per customer)	SAIFI (Number per customer)	SAIDI (Minutes per customer)	SAIFI (Number per customer)
Urban	80	1.2	350	4

[1] Granted by the Minister for Industry, Resources and Energy under the *Electricity Supply Act 1995 (NSW)*

[2] SAIFI is calculated as the total number of interruptions that have occurred during the relevant period, divided by the number of customers. Momentary interruptions (which in NSW are currently defined as interruptions less than one minute) are typically not included. In practice, the length of the "given period" is one year.

[3] SAIDI is calculated as the sum of the duration of all customer interruptions over the period divided by the number of customers. Momentary interruptions (i.e. those of less than one minute) are typically not included. In practice, the length of the "given period" is one year.

[4] The Hon. Anthony Robbers MP Minister for industry, Resources & Energy, Reliability and Performance Licence Conditions for Electricity Distributors, 1 December 2016, pp. 18-19 – available at:

https://www.ipart.nsw.gov.au/files/sharedassets/website/shared-files/licensing-administrative-electricity-network-operations-proposed-new-licence-conditions/ausgrid-ministerial-licence-conditions-1-december-2016.pdf

3 Description of Identified Need

This section describes in further detail the identified need at Mascot Zone Substation.

It explains that the increasing risks at Mascot zone substation are driven by the following:

- the age and condition of the 11kV switchgear is exposing customers to an increasing risk of asset failure and subsequent supply interruption;
- limited load transfer capability as a result of thermal capacity limitations of 11kV feeders and the existing loading of adjoining zone stations; and
- the age and condition of the 33kV underground cables are approaching the end of serviceable lives.

3.1 Asset condition

The existing 33kV feeders supplying Mascot zone substation are paper insulated lead covered (PILC) cables. This type of cable is also commonly known as a Solid/HSL cable, and they typically have a life of 60 to 70 years. The 33kV PILC cables supplying Mascot are over 70 years old. Their condition is deteriorating and failures in the future can be expected.

The compound insulated and air insulated 11kV switchgear as well as the associated 11kV oil circuit breakers at Mascot zone substation are approaching the end of their serviceable lives. The compound insulated 11kV switchgear was installed when Mascot zone substation was commissioned and is currently over 70 years old. The air insulated 11kV switchgear is over 50 years old. The compound insulated switchgear houses 11kV oil circuit breakers, which pose operational and safety risks.

In the past, there have been a considerable amount of 11kV switchgear failures, which have resulted in a range of adverse consequences ranging from single equipment failures to multiple equipment failures impacting the operation of the entire substation. Consequently, Ausgrid expects that compound insulated switchgear at Mascot zone substation have an increasing likelihood of failure and involuntary load shedding.

In addition, the 33kV underground cables supplying Mascot zone are over 70 years old, and some cable sections have experienced failures over the years. The remaining assets within the substation such as power transformers, protection and control building are approaching the end of their service lives.

A cost benefit analysis has recommended the replacement of the 11kV switchboard at Mascot zone substation by 2022/23.

3.2 Load transfer capability and supply restoration

The expected cost of any involuntary load shedding is dependent on underlying assumptions relating to the level load transfer capability, either within the Mascot 11kV feeder network or to neighbouring zone substations that could supply some portion of the Mascot load.

Load transfer capability represents the amount of customer load that can be recovered via network switching opportunities following an electricity supply interruption. The load transfer capability is modelled considering the failure modes of the 11kV switchgear, for example, fire originating from the 11kV oil circuits breakers. Such an event would require one or more of the 11kV switchgear groups to be disconnected from the electricity network to enable supply restoration and equipment repairs to be undertaken in a safe manner.

Accordingly, our modelling of the load transfer capability relating to the identified need at Mascot zone substation has been determined per switchgear group and therefore we have determined each switchgear group's contribution to the forecasted EUE. A higher load transfer capability reduces EUE since more customer load can be recovered via switching following a supply interruption event and vice versa.

Ausgrid estimates that the transfer capability for each switchgear group is as per Table 3.1. The transfer capability is the amount of load that can be transferred away from that switchgear group, either internally within Mascot zone substation to other switchgear groups or to other zone substations, or a combination of both.

Table 3.1 – Load transfer capability by 11kV switchgear group

Switchgear group no.	Switchgear insulation type	Normal configuration	Transfer capability (MVA)
1	Compound	Standby (not normally on-load)	N/A
2	Compound	On-load	1.3
3	Compound	On-load	5.3
4	Compound	On-load	6.5
5	Air	On-load	1.6
6	Air	On-load	7.0

4 Assessment Methodology and Assumptions

This section outlines the methodology that Ausgrid has applied in assessing market benefits and costs associated with the credible options considered.

4.1 Probabilistic planning methodology

Ausgrid applies a probabilistic planning methodology where the costs and benefits for each credible option are measured against a ‘do nothing’ base case. Under the base case, Ausgrid is assumed to undertake escalating regular and reactive maintenance activities as the probability of failure and severity of outages increases over time in the absence of an asset replacement program.

The analysis has been undertaken over a 20-year period, from 2019 to 2039. Ausgrid considers that a 20-year period takes into account the size, complexity and expected life of the relevant credible options to provide a reasonable indication of the market benefits and costs of the options. The capital components of the credible options have asset lives typically greater than 20 years. Therefore, Ausgrid has included the terminal value of these assets in the economic modelling to appropriately capture the depreciated value of these long-lived assets.

The following sections describe the key assumptions and inputs used in the cost-benefit analysis.

4.2 Value of customer reliability

The cost of unserved energy is calculated using the Value of Customer Reliability (VCR). This is an estimate of how much value electricity consumers place on a reliable electricity supply.

In assessing the credible options to alleviate the impact of constraints on its network, Ausgrid has applied VCR values based on the Australian Energy Market Operator’s (AEMO) 2014 Value of Customer Reliability Review[5] using CPI to escalate the AEMO estimate to current real values. Ausgrid has applied a VCR of $40,036/MWh in preparing this non-network options report.

VCR sensitivity values will be applied when Ausgrid conducts its more detailed analysis of the credible options in its Draft Project Assessment Report.

4.3 Discount rate

A real discount rate of 3.22% has been applied in undertaking the initial assessment of the network options presented in this report. However, further consideration of the discount rate and sensitivity analysis will be provided in the Draft Project Assessment Report.

4.4 Ausgrid’s approach to estimating project costs

Ausgrid has estimated capital costs by considering the scope of works necessary under each credible option together with costing experience from previous projects of a similar nature. Where possible, Ausgrid has also estimated capital costs for each credible option using supplier quotes or other pricing information.

Operating and maintenance costs have been determined for each option by comparing the operating and maintenance costs with the option in place to the operating and maintenance costs without the option in place. These costs are included for each year in the planning period. If operating and maintenance costs are reduced with an option in place, the cost savings are treated as a benefit in the assessment.

Operating costs have been estimated for each credible option and the base case by considering:

- the probability and expected level of network asset faults, which translates to the level of corrective maintenance costs; and

[5] AEMO, *Value of Customer Reliability Review*, September 2014, Final Report.

- the level of regular maintenance required to maintain network assets in good working order, including planned refurbishment costs.

All options reduce the incidence of asset failures relative to the base case, and hence the expected operating and maintenance costs associated with restoring supply.

Ausgrid has also included the financial costs associated with safety outcomes that are assumed to be avoided under each of the options, relative to the base case.

The capital cost estimates for all network options are indicative costs only. The capital cost estimates used for this non-network options report are expressed in constant 2018 dollars. Cost estimates will be further refined in the course of Ausgrid preparing the Draft Project Assessment Report.

4.5 Market benefits are expected from reduced involuntary load shedding

Ausgrid considers that the only relevant category of market benefits prescribed under the NER for the RIT-D relates to changes in involuntary load shedding.

The approaches and assumptions Ausgrid has made to estimate the financial impact in avoided unserved energy are outlined in section 4.5.1 below.

4.5.1 Avoided unserved energy (reduced involuntary load shedding)

Unserved energy is the amount of energy demanded by customers but unmet due to interruption of their electricity supply. A reduction in the unserved energy expected from implementation of a credible option, relative to the base case, results in a positive contribution to market benefits in the form of avoided unserved energy.

The Expected Unserved Energy (EUE) is the probability weighted average amount of load that would need to be involuntarily curtailed due to system limitations (i.e. the network being overloaded). These limitations arise from the unavailability of network elements and the resulting reduction in network capability to supply the load. It also relates to the availability of network connectivity and the design configuration at the substation.

The load duration curve at a substation is used to determine the energy at risk and/or the amount of load curtailment required at certain loading levels. The amount of load curtailment can be determined by using a discrete number of load points and the capacity adequacy at the substation following various credible contingencies and/or outages (i.e. single or multiple transformers out of service).

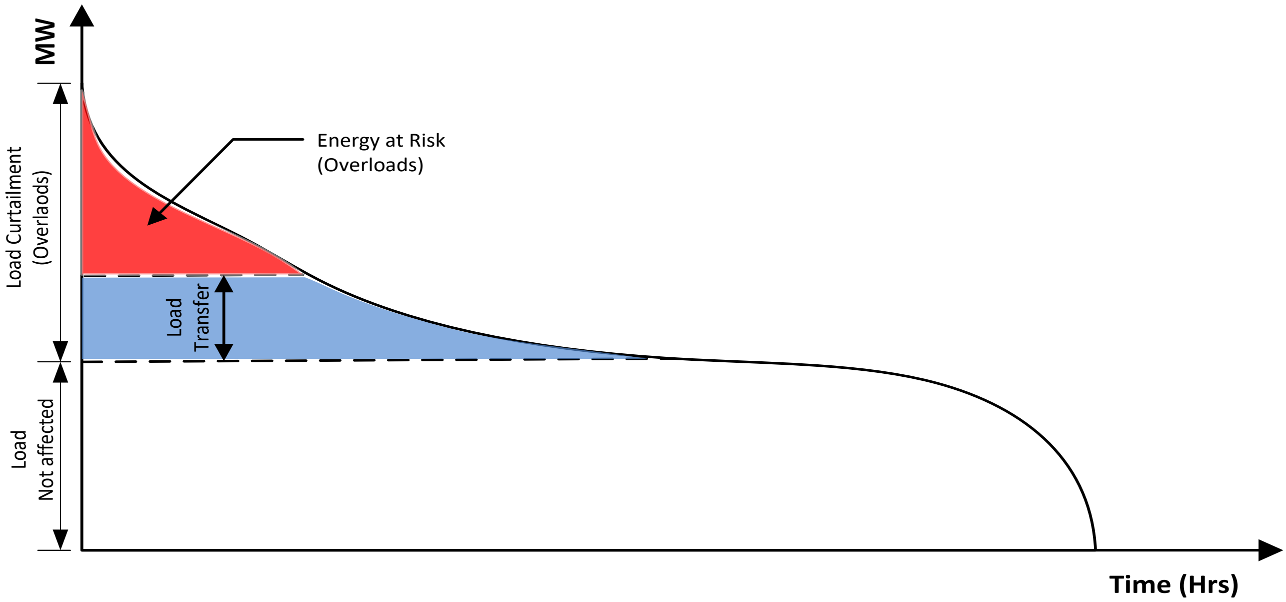
The following diagram illustrates the load curtailment due to overloads and the treatment of load transfer capability. During an overload condition, initially the necessary amount of load is shed, and then partial load is restored via available load transfer opportunities via opening and closing of network switches. Energy at risk is made of two components:

- Load that is lost immediately following the supply interruption, which includes the time required to locate the fault and to restore supply via network switching. Depending on factors such as the load level and transfer capability, full supply restoration may not be possible; and

- Load not able to be switched away via load transfers (using the process described above) and therefore subject to a longer supply interruption until repairs can be carried out.

An illustration of the EUE contributions of these components is shown in Figure 4.1 below.

Figure 4.1: Illustration of Load Curtailment



The calculation of the energy at risk considers the zone substation load forecast which includes the quantity of new additional load requested in customer connection applications. The expected unserved energy is the total of the energy at risk that would result from various outage states and weighted by the probability of each state.

The market benefit measured in dollars as a result of the preferred option by eliminating unserved energy with a network solution is estimated by multiplying the unserved energy by the VCR. The VCR is measured in dollars per MWh and represents the economic impact of unserved energy on customers.

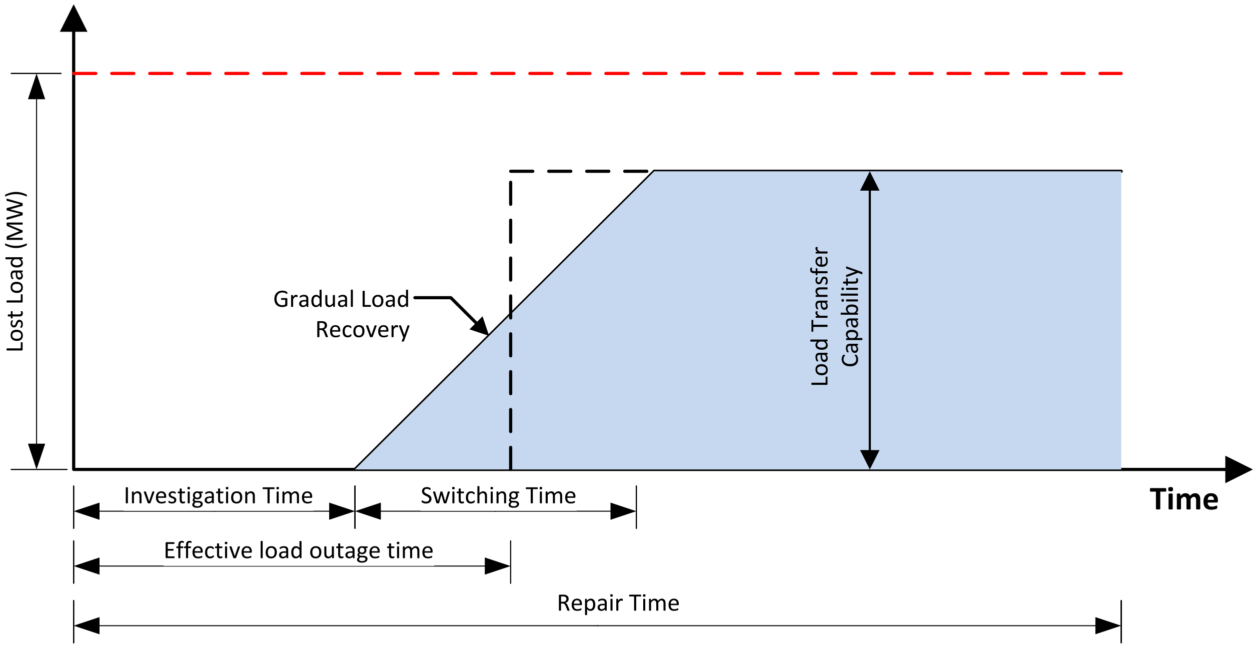
4.5.2 Load restoration

Load transfer capability as illustrated in Figure 4.1 above at a substation is the amount of load that can transferred to adjacent parts of the electricity network via existing 11kV switching opportunities. The level of load transfer capability is dependent upon the level of network connectivity, both within the zone substation and to neighbouring zone substations, the utilisation of the 11kV feeders and the size of individual distribution substations along the 11kV feeders.

To evaluate network consequence (unserved energy), it is essential to consider load transfer capability which can be restored within a reasonable amount of time until the failed equipment is being repaired or replaced.

Figure 4.2 shows the treatment of supply recovery following interruption.

Figure 4.2: Treatment of supply recovery following interruption



5 Summary of Potential Credible Options

This section provides a summary of the potential credible options that Ausgrid has identified as part of its network planning activities to address the identified need. Consideration is also given to other options that have not been progressed because they were found to be technically or commercially unfeasible.

Whilst this section also identifies the preferred network option, it should be noted that the analysis presented is indicative because it is based on high level cost estimates. Site specific investigations or detailed option investigations are not available at this stage.

5.1 Base case

The Base Case considers a 'do nothing' approach, in which no action is implemented to address the identified network need. The purpose of this is to establish a reference against which all credible options are compared, enabling the identification of the preferred option as the one that maximises net benefits against a 'do nothing' case.

5.2 Credible network options

Option 1 – Brownfield replacement of Mascot 11kV switchgear and replace 33kV feeders.

Option 1 involves a brownfield replacement of equipment by utilising the existing Mascot Zone Substation site and retaining the primary voltage source at 33kV. The existing HSL 33kV feeders originated from Bunnerong North STS will be replaced by establishing new XLPE feeders from nearby and recently commissioned Alexandria STS, which is a feeder route of much shorter distance than from Bunnerong STS.

The proposed scope of works for Option 1 includes:

- Staged installation of new 11kV switchgear in a new switchroom building;
- Installation of four new 33kV feeders from nearby Alexandria STS;
- Installation of four 33/11kV 33MVA transformers to replace the existing six 15MVA 33/11kV units; and
- Decommissioning of existing compound and air insulated 11kV switchgear, 33/11kV transformer units and associated 33kV HSL feeder connections.

Subject to the timing of new major customer connections at Alexandria STS, this site may need to be expanded with an additional transformer and 33kV switchgear.

Option 1 is estimated to cost approximately $51 million (real $18/19), excluding a possible expansion of Alexandria STS. It is also estimated that project development activities would take two years and project construction and the project would be completed by FY2026.

Option 2 – Greenfield establishment of new 132/11kV zone substation on alternative site.

This option involves the establishment of a replacement 132/11kV zone substation on a nearby greenfield site with modern equivalent switchgear connected into the 132kV feeders in the area.

The proposed scope of works for Option 2 includes:

- Site acquisition;
- Installation of two 132/11kV 50MVA transformer units, with provision for a future third transformer;
- Installation of 132kV switchgear in a new switchroom building;
- Installation of two new 132kV cable sections, approximately 0.5km long, to connect to existing 132kV feeder 91M/3 from TransGrid owned Beaconsfield BSP;
- Installation of new 11kV switchgear in a new switchroom building;
- Installation of 11kV feeders to transfer load from existing Mascot 33/11kV Zone Substation to the new Mascot 132/11kV zone substation;

- Decommissioning of all existing Mascot 33/11kV zone substation assets, with the exception of one 33kV feeder required to maintain existing 33kV supply to Sydney Airport; and
- Remediation and sale of the existing Mascot zone substation site.

Option 2 is expected to cost approximately $38 million (real $18/19), assuming the cost of property acquisition for the new site is equivalent to the proceeds from the sale of the existing site (i.e. net zero). It is expected that the project would be completed by 2022/23.

Option 3 (this option has been considered but not progressed) - Transfer of all 11kV load from Mascot Zone Substation to adjacent zone substations.

This option involves offloading Mascot zone substation by transferring all 11kV loads to surrounding zone substations such as St Peters, Green Square and/or Zetland zone substations.

The surrounding zone substations do not have adequate spare capacity to allow for all load to be transferred from Mascot zone substation. Hence, this option was not considered further.

Option 4 (this option has been considered but not progressed) – Brownfield replacement of Mascot 11kV switchgear on same site and replace existing 33kV supply with new 132kV primary supply.

This option involves a brownfield replacement of equipment by utilising the existing Mascot zone substation site and converting it to a 132/11kV zone substation utilising nearby 132kV feeders from Beaconsfield BSP.

The proposed scope of works for this option includes:

- Staged installation of new sections of 11kV switchgear in a new switchroom building;
- Installation of two 132/11kV 50MVA transformers to replace the existing arrangement of 33/11kV units, with provision for a future third unit;
- Installation of 132kV switchgear in a new switchroom building;
- Installation of two new 132kV cable sections to connect into either existing 132kV feeder 91M/3 from TransGrid owned Beaconsfield BSP, or feeder 264 from Beaconsfield BSP; and
- Decommissioning of existing compound and air insulated 11kV switchgear, 33/11kV transformer units and associated 33kV HSL feeder connections.

This option was not further progressed due to insufficient space on site to accommodate a future three-transformer 132/11kV substation arrangement.

5.3 Preferred network option

Table 5.1 below summarises the indicative capital cost estimates for each of the four options identified in Section 5.2.

Table 5.1: Indicative costs of network options

Option	Total indicative cost ($m real 18/19)
Option 1 - Brownfield replacement of Mascot 11kV switchgear and 33kV feeders	51
Option 2 - Greenfield establishment of new 132/11kV zone substation on alternative site	38
Option 3 - Transfer of all 11kV load from Mascot Zone Substation to adjacent zone substations	Not further progresed
Option 4 - Brownfield replacement of Mascot 11kV switchgear on existing site and replace existing 33kV supply with new 132kV primary supply	Not further progresed

Based on the indicative cost estimates presented above, Ausgrid has identified Option 2 as the preferred network option.

6 Technical Characteristics of Non-Network Options

This section sets out the technical characteristics of the network need[6]. This information is provided to enable proponents of non-network solutions to understand the identified need, and to tailor their proposals accordingly.

Ausgrid wants to explore all possible non-network solutions with proponents to deliver the lowest-cost solution to the need. We recognise that proponents may require additional specific information to develop their proposals and that application of demand management has not traditionally been applied to network needs driven by aged asset issues. Accordingly, we encourage proponents to contact us as early as possible, to ensure that we can provide all necessary information that they may require.

In Section 6.9 we identify the accompanying datasets that are provided with this NNOR to assist demand management proponents in developing proposals.

6.1 Potential Credible Non-Network Options

Non-network alternatives, such as embedded generation or demand management can alleviate supply risks and potentially defer the need for capital investment in the electricity network. The embedded generation or demand management schemes for this project would need to be connected to, and supply into the 11 kV distribution or low voltage network of the target area (see Section 6.2 below) to offload the Mascot zone substation 11 kV feeders and therefore reduce the risk associated with unplanned outages within the Mascot supply area.

Possible embedded generators could include (but not limited to):

- Temporary connection of embedded generators such as gas or diesel generators that are operated at specific times;
- Co-generation from industrial processes;
- Agreements with energy users to operate their existing standby generatiors when called upon to do so; and
- Generation using renewable energy sources, such as solar, wind or land-fill powered generation.

A reduction of peak demand, using demand management, could be achieved by customers shifting their usage to non-peak periods, using more energy efficient appliances or by reducing energy wastage.

Demand management schemes could include (but not limited to):

- Peak load usage shifting or lopping;
- Interruptible load at a reduced electricity rate, which would be covered by a supply agreement that the load can be interrupted during network emergencies; and
- Power factor correction.

Other demand management measures could be:

- Installation of energy efficient equipment in energy users' premises that permanently reduces customer demand including power factor correction equipment;
- "Fuel switching' from electricity to another fuel, such as gas; and
- Installation of energy storage in combination with a generation source such as rooftop solar PV.

Ausgrid will assess demand management options put forward by proponents with the objective of achieving the required demand reductions necessary to make the proposed supply-side project deferral technically viable at least cost.

Ausgrid envisages that, based on the customer load profile of the target area and the magnitude of customer load that would be unmet in the event of an electricity supply interruption (loss of supply to one or more 11kV switchgear groups), a plausible solution may comprise a mix of permanent and temporary demand reductions.

We will assess each option separately to determine the optimum non-network solution mix.

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[6] In accordance with Clause 5.17.4s(4) of the Rules.

6.2 Target area

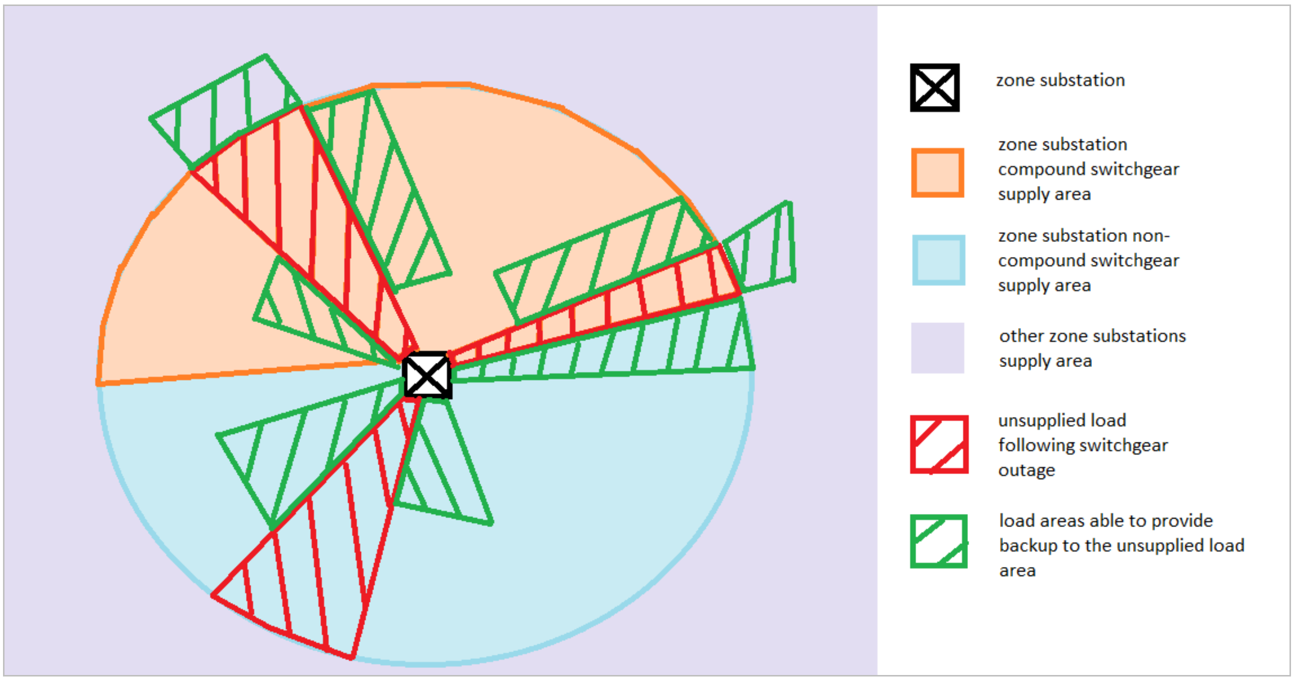
6.2.1 Target area methodology

The target area from which Ausgrid is seeking demand reductions is **not** the entire Mascot zone substation supply area. The target area is a subset of the Mascot area and selected adjoining zone substation areas and is determined based on the following factors:

- "Unsupplied load" under outage conditions. These are the parts of the Mascot load area that would be unsupplied following an outage event;
- Load transfer capability. This is the ability to re-supply customers using alternative supply paths due by utilising the interconnectivity of the network. This is carried out by operating network switching devices following an outage event to restore supply to as many customers as possible;
- "Back-up" 11kV feeders. These are the adjacent portions of the Mascot network that do not experience loss of supply in an outage event, however, demand reductions here also reduce the level of expected unserved energy to a similar degree as the unsupplied area due to network connectivity; and
- Different types of switchgear. This means differentiating between the portions of the Mascot load area supplied by compound-insulated switchgear and air-insulated switchgear. These different types of switchgear have different failure rates, leading to differing levels of expected unserved energy.

The above factors are illustrated in the Figure 6.1 below.

Figure 6.1: Unsupplied load and backup areas (illustrative only)



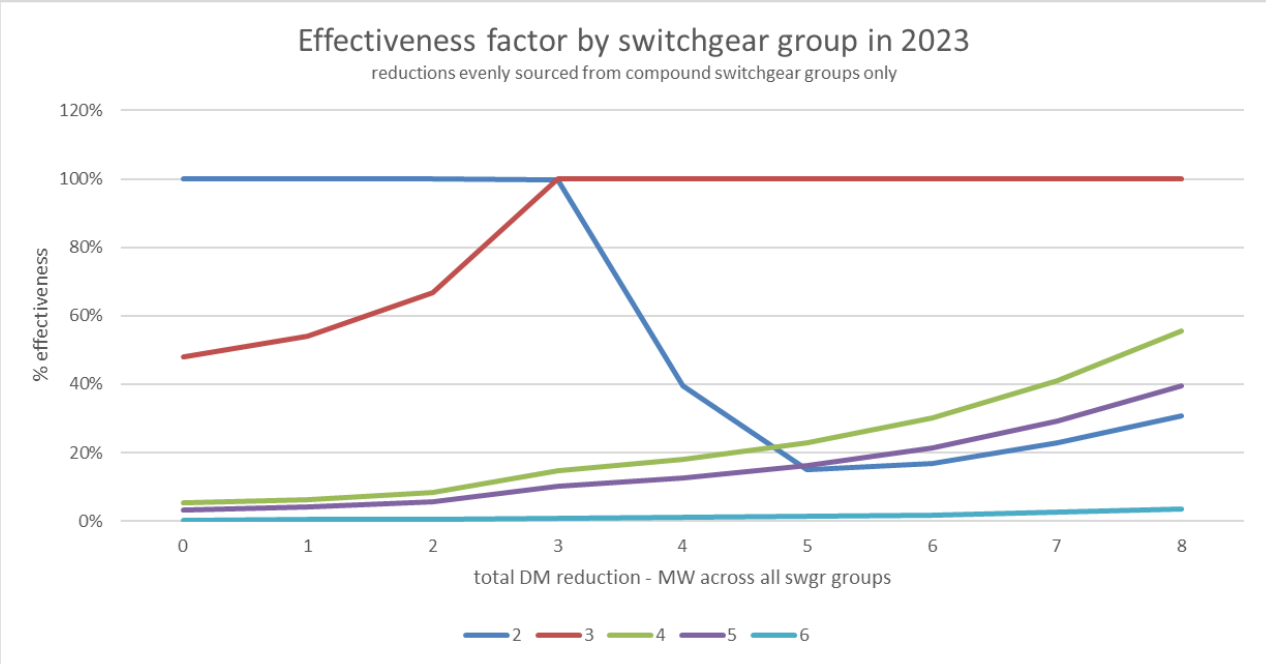
The differences in equipment failure rates between the compound and air insulated switchgear result in different levels of "effectiveness" of demand reductions within the Mascot area. We have calculated effectiveness factors based on:

- The expected cost of unserved energy per unit load ($EUE per MW) per switchgear group (inclusive of load transfer capability) for Mascot in 2022/23 (supply option expected completion year); and
- Conversion of the $EUE per MW into a percentage scale, where 100% effectiveness is assigned to the switchgear group with the highest $EUE per MW for a given amount of demand reductions (effectiveness of demand reductions for other groups is calculated relative to the 100% group).

The indicative effectiveness factors by switchgear group are shown in Figure 6.2 below for DM reductions of up to 8 MW. The reductions are assumed to be sourced from switchgear groups 2, 3, 4 and 5 only, as they have indicative effectiveness factors greater than 1%. Importantly, please note that the indicative effectiveness factors change dependent upon the amount of demand reductions already achieved. Initially, group 2 offers the highest indicative effectiveness as this group has a relatively low transfer capability in comparison to the other groups. As demand is progressively reduced from group 2, it no longer offers the highest effectiveness after a total of 3 MW is achieved across Mascot zone and at the same time, the relative value of demand reductions from the other switchgear groups increases.

Note that Figure 6.2 is indicative only. The factors were based upon the application of demand reductions across each group weighted by their total load.

Figure 6.2: Indicative effectiveness factors of demand reductions in 2022/23 by switchgear group



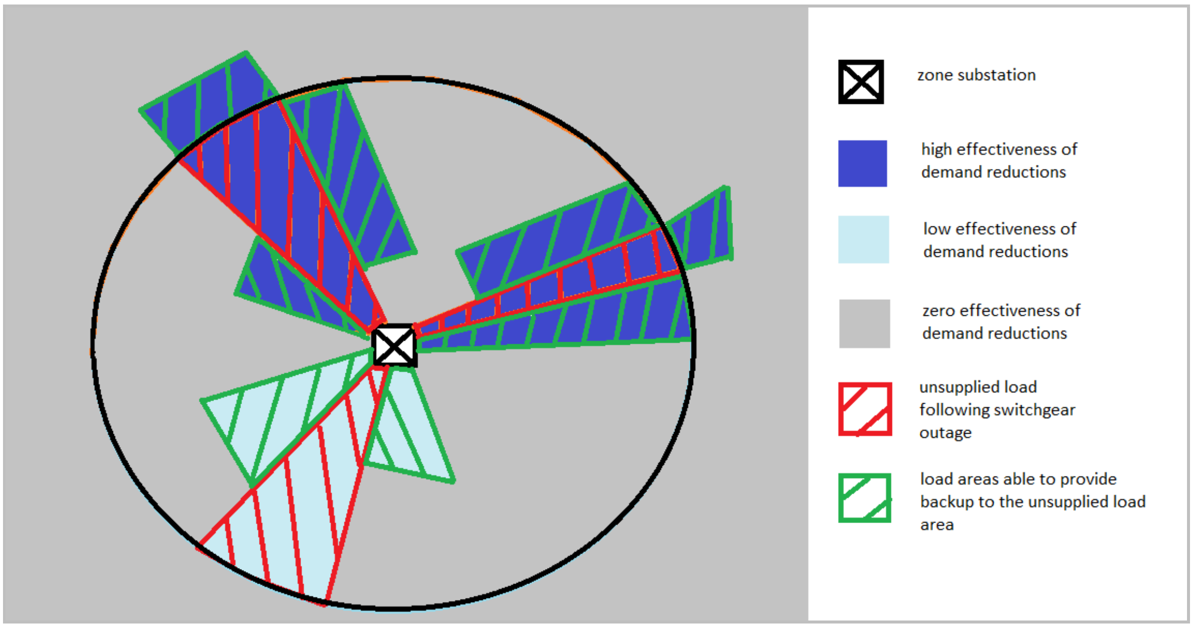
To arrive at a defined target area at Mascot, we have estimated that the likely range of demand reductions necessary to enable deferral of the proposed supply solution at Mascot would be about 3 to 5 MW at peak. This results in the following values for the indicative effectiveness factors per switchgear group, shown in Table 6.1 below. Note that these factors will vary depending upon the location of the demand reductions proposed by demand management proponents.

Table 6.1: Average indicative effectiveness factor per switchgear group in 2022/23

Switchgear group no.	Switchgear insulation type	N state configuration	% effectiveness range	Effectiveness level
1	Compound	Standby	N/A	N/A
2	Compound	On-load	15-39%	Moderate
3	Compound	On-load	100%	High
4	Compound	On-load	18-23%	Moderate
5	Air	On-load	13-16%	Moderate
6	Air	On-load	1%	Low

Considering the areas of high and moderate effectiveness only, this means the target area is restricted to that supplied by the switchgear groups 2 to 5, plus adjacent back-up sections of the network as shown in Figure 6.3 below. Areas of low effectiveness are indicated, corresponding to the switchgear group 6. There are also areas of zero effectiveness where customers are not expected to experience supply interruptions in the event of a switchgear group outage at Mascot zone.

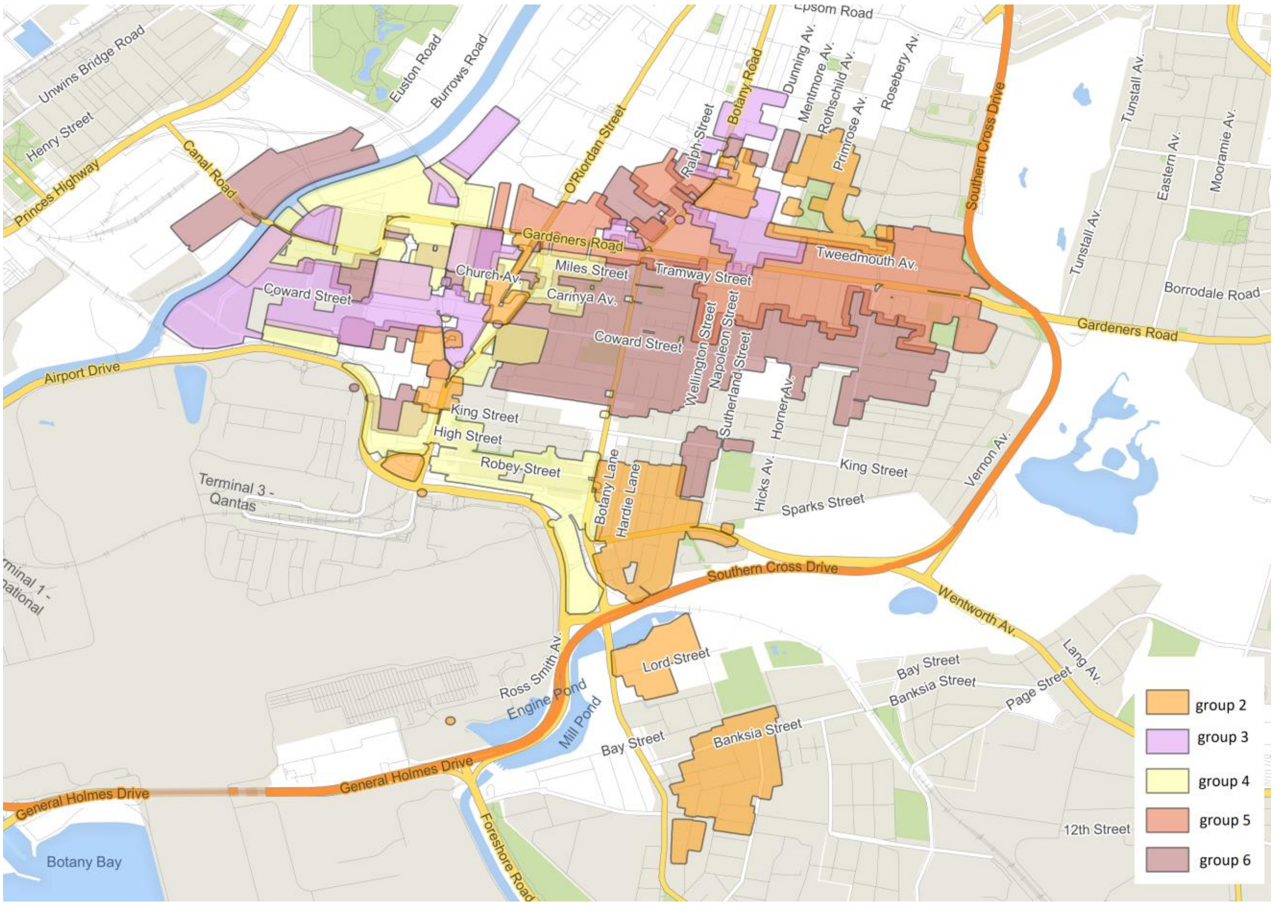
Figure 6.3: Medium-High and low effectiveness areas (illustrative only)



6.2.2 Mascot switchgear group areas

Figure 6.4 below shows the entire Mascot zone substation supply area by switchgear group. This map is produced using a Google Maps '.KMZ' overlay and is based on an estimate of Mascot's electrical network connectivity in 2022/23, when the preferred network supply option would be expected to be commissioned in the absence of any non-network solutions.

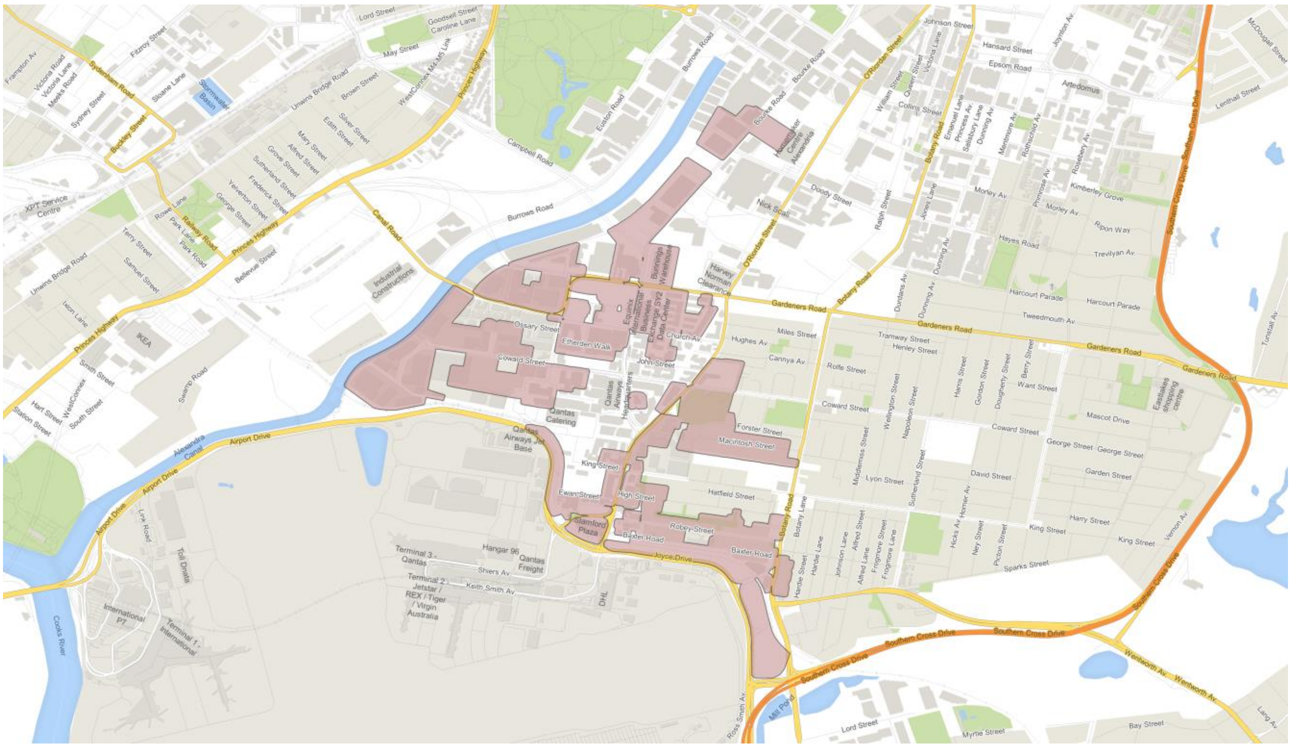
Figure 6.4: Spatial map of Mascot switchgear group areas



6.2.3 Mascot specific target area

Accordingly, following the methodology in described section 6.2.1 above, the target area for Mascot is shown in Figure 6.5 below, where the low and zero effectiveness areas are ignored. This map is produced using a Google Maps '.KMZ' overlay and is based on an estimate of Mascot's electrical network connectivity in 2022/23, when the preferred network supply option would be expected to be commissioned in the absence of any non-network solutions.

Figure 6.5: Spatial map of target area



Information underlying this map is provided as part of the datapack as '.KML' and '.JSON' files accompanying this NNOR to assist non-network proponent in developing proposals.

6.3 Customer Demand Characteristics

Customer demand characterics affect the location, size and type of demand management solutions that are may be feasible in addressing the identified need. Below we provide the customer demand characteristics of the target area. This information is included in the datapack (refer Section 6.9).

6.3.1 Customer characteristics of Mascot zone substation

Mascot zone substation serves a mixture of residential and non-residential customers. While non-residential customers comprise 16% of the total number of customers supplied from Mascot zone by count, they contribute 83% of the annual electricity consumption. Out of a total of just under 11,000 customers, 253 customers, or 2.3%, have rooftop PV systems with a total installed capacity of around 1 MW.

This is shown in the customer characteristics Table 6.2 below for the entire Mascot zone based on FY2018 data. Table 6.2 is provided for background information only. DM proponents should focus on the figures presented in Table 6.3 following which are specific to the target area.

Table 6.2 – Customer characteristics – entire Mascot zone substation

Item	Residential	Non-Residential	Total
Number of Customers	9,204	1,723	10,927
% of Customers	84%	16%	
Annual Consumption FY18 (MWh)	35,377	168,710	204,087
% of Annual Consumption	17%	83%	
Number of Solar Customers	215	38	253
% of Sector customers with solar	2.3%	7.1%	2.3%
Solar PV installed capacity (kW)	529	474	1002
Average Annual Consumption (MWh per customer)	3.8	98	

6.3.2 Customer characteristics of target area

The customer characteristics of the target area, which includes customers that are supplied from adjacent zone substations, is shown in Table 6.3 below:

Table 6.3 – Customer characteristics – target area

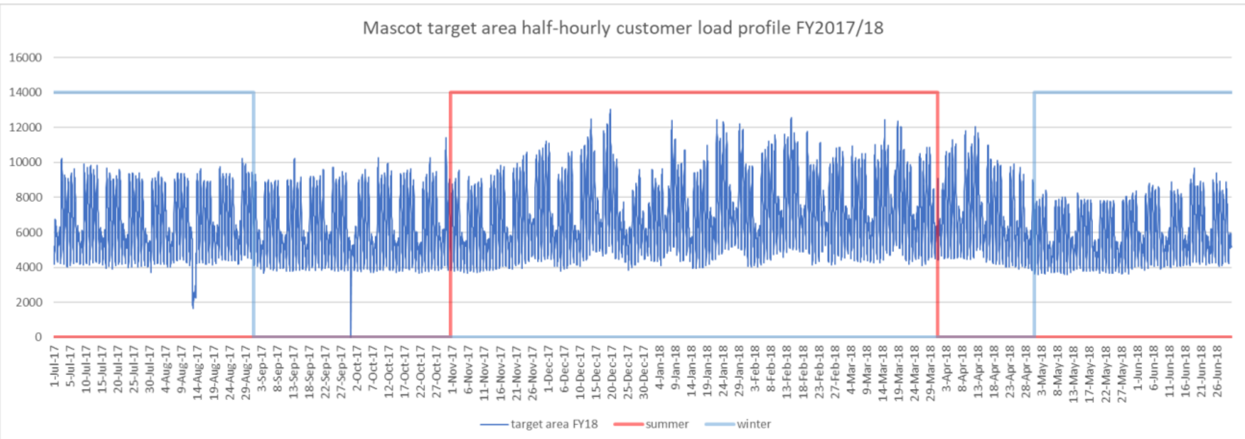
Item	Residential	Non-residential	Total
Number of Customers	1,872	692	2,564
% of Customers	73%	27%	100%
Annual Consumption FY18 (MWh)	5,981	50,729	56,710
% of Annual Consumption	11%	89%	100%
Number of Solar Customers	15	12	27
% of Sector customers with solar	0.8%	5.8%	1.1%
Solar PV installed capacity (kW)	32	107	139
Average Annual Consumption (MWh per customer)	3.2	73	

6.3.3 Load profiles

In this section we present the annual and seasonal peak day profiles of the target area. These have been derived based on a mixture of actual metered and derived interval data at the distribution substation level. Information underpinning the charts is provided as part of the datapack.

The aggregate FY2018 load profile of the target area is shown in Figure 6.6 below which illustrates broadly the seasonality of customer demand and the summer peaking characteristic. Demand is more variable over the summer months in comparison to other seasons.

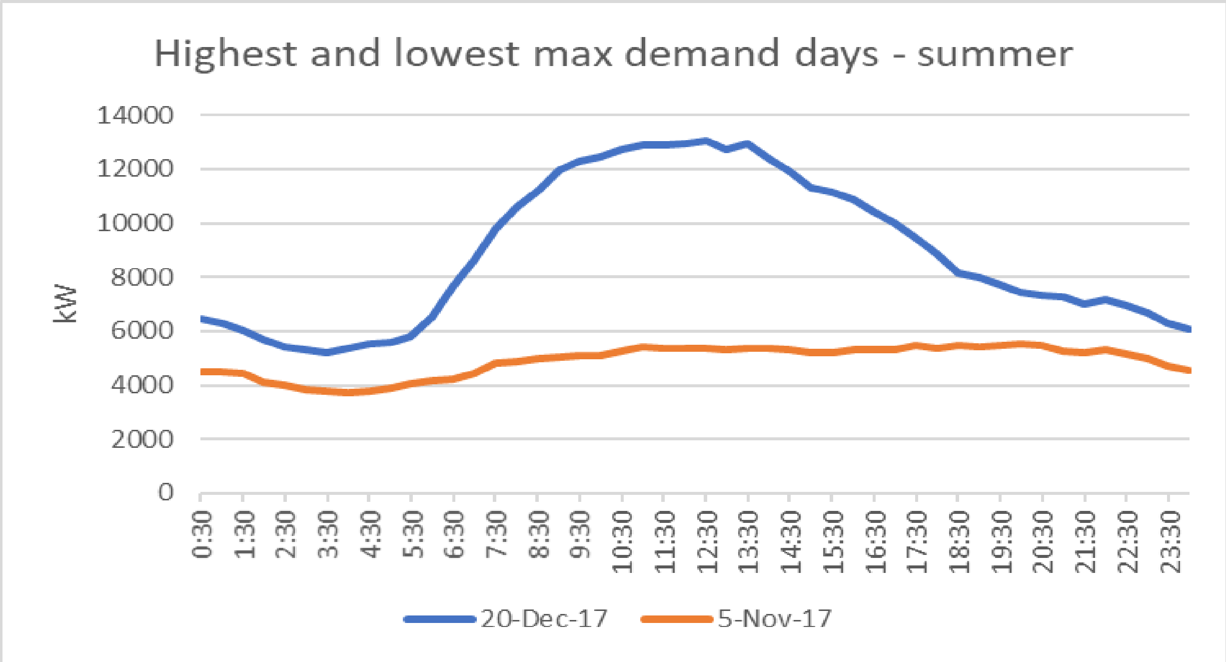
Figure 6.6 – Mascot target area half-hourly customer load profile FY2017/18



6.3.4 Summer day load profiles

The target area summer peak demand occurs on hot days driven predominantly by commercial loads with the time of peak typically occurring in the early afternoon. Over the FY2017/18 period, summer maximum demand of around 13.1 MVA occurred on 20 Dec 2017 and the lowest maximum demand was 5.5 MVA which occurred on 5 Nov 2017, with respective daily profiles as shown in shown in Figure 6.7 below.

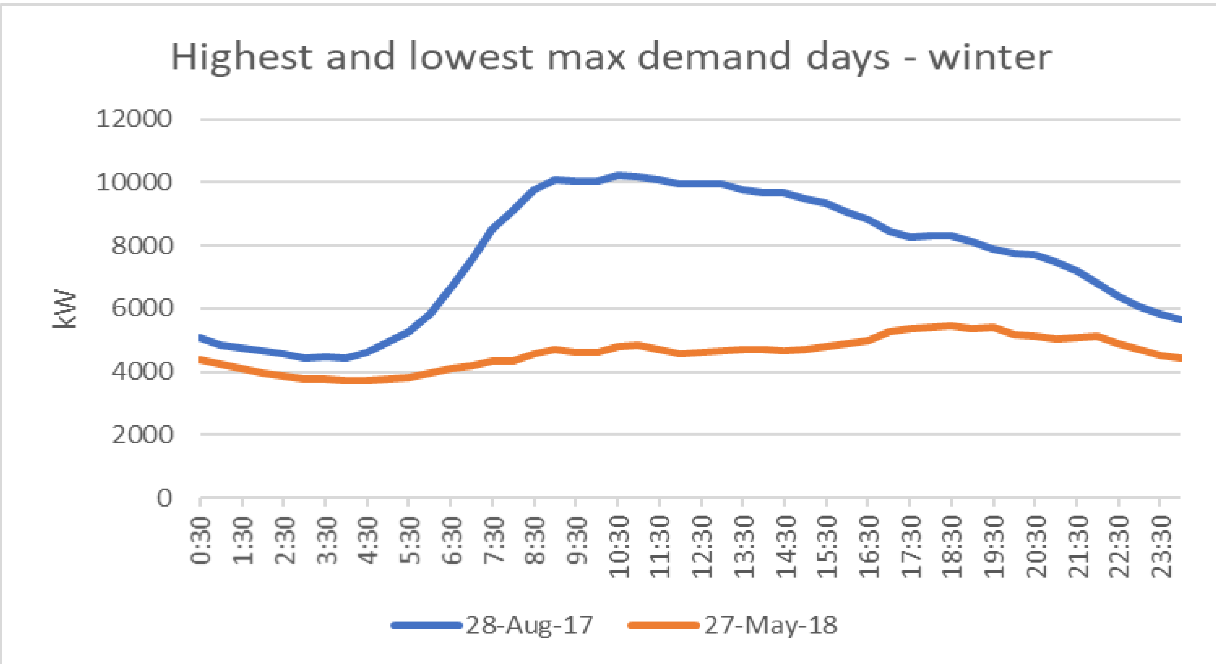
Figure 6.7 – Target area highest and lowest summer max demand days in FY2017/18



6.3.5 Winter day load profiles

Over FY2017/18, the target area winter maximum demand of 10.2 MVA occurred on 28 Aug 2017 and the lowest winter maximum demand of 5.4 MVA occurred on 27 May 2018. The respective load profiles for these days is shown in Figure 6.8 below.

Figure 6.8– Target area highest and lowest winter max demand days in FY2017/18

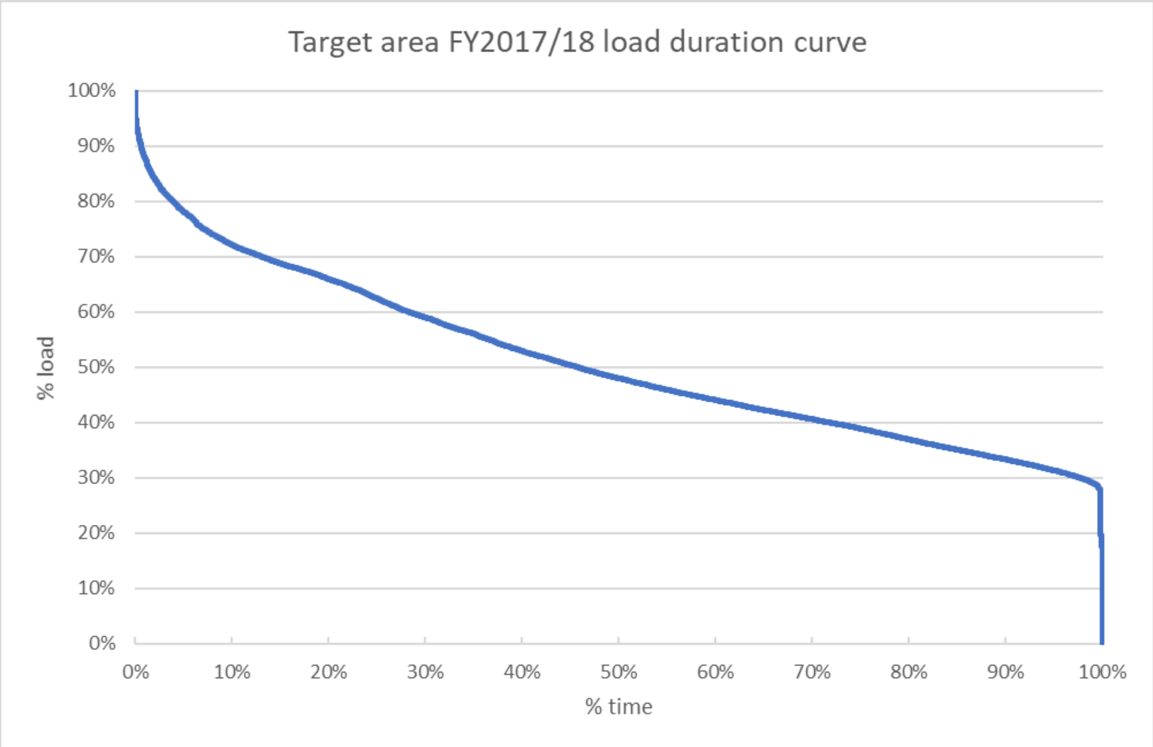


6.3.6 Load duration curve

Figure 6.9 below shows the load duration curve (LDC) of the target area, which highlights the degree of "peakiness" of the customer demand profile and the amount of time that load exceeds a given load level. The LDC is constructed by taking the entire year FY2017/18 half-hourly interval demand data of the target area (Figure 6.6) and sorting from highest to lowest. Figure 6.9 shows that:

- The top 5% of demand in the target area occurs for around 8 hrs per year;
- The top 10% of demand in the target area occurs for around 57 hrs per year; and
- The top 20% of demand in the target area occurs for around 348 hrs per year.

Figure 6.9 – Target area load duration curve



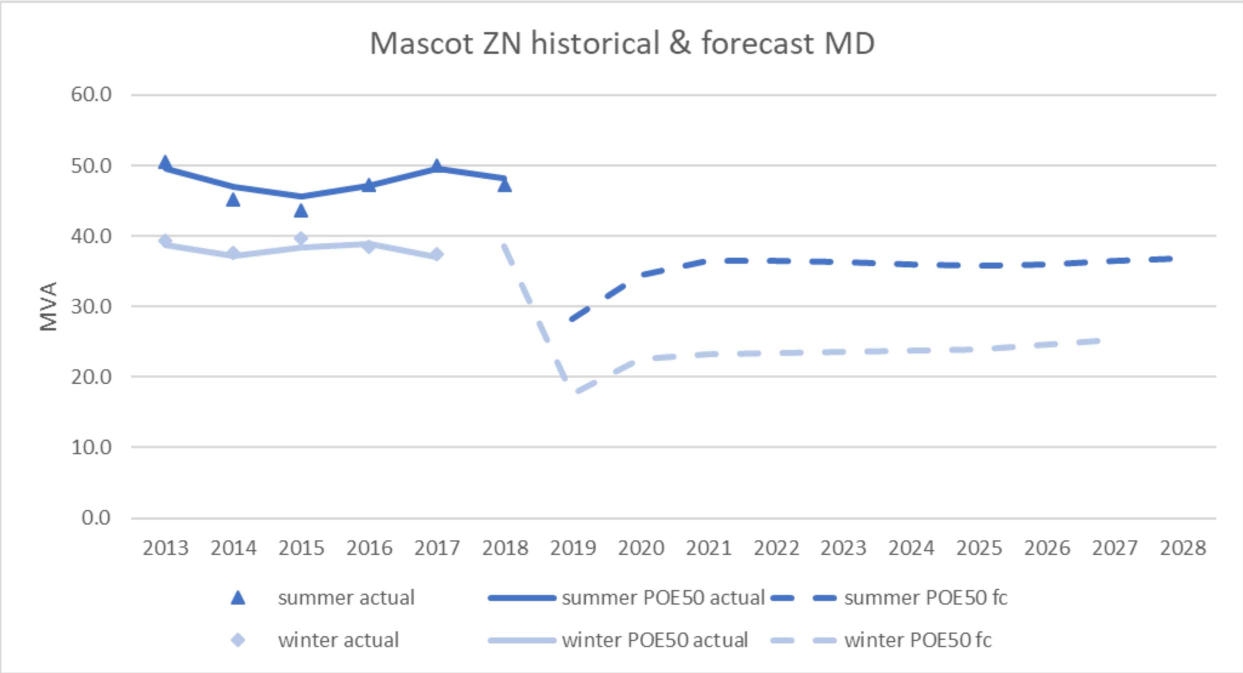
6.3.7 Forecast load profiles (summer 2022/23)

In sections 6.3.2 to 6.3.6 above, we provided historical demand data information relating to the target area. However, Ausgrid is seeking demand reductions in the future where we would implement a supply-side solution to address the identified need if non-network options are found not viable, namely prior to summer 2022/23.

In our forecasting and network planning processes, Ausgrid does not derive individual load profiles for future years. Rather, we use a historical load profile and assume this profile would be representative in a future year, scaled appropriately to the projected maximum demand in that year in our probabilistic planning methodology.

Ausgrid's maximum demand forecast is derived at the zone substation level. We do not have a specific forecast for the target area. However, we consider it appropriate that the Mascot zone substation 50% Probability of Exceedance level (POE50) forecast can be applied to derive a proxy for the future expected maximum demand of the target area. Figure 6.10 below shows the historical actual demand, the POE50 weather corrected historical actual demand and the POE50 forecast demand for both summer and winter for Mascot zone substation. Figures underlying this forecast are contained within the datapack.

Figure 6.10 – Mascot zone substation POE50 maximum demand forecast



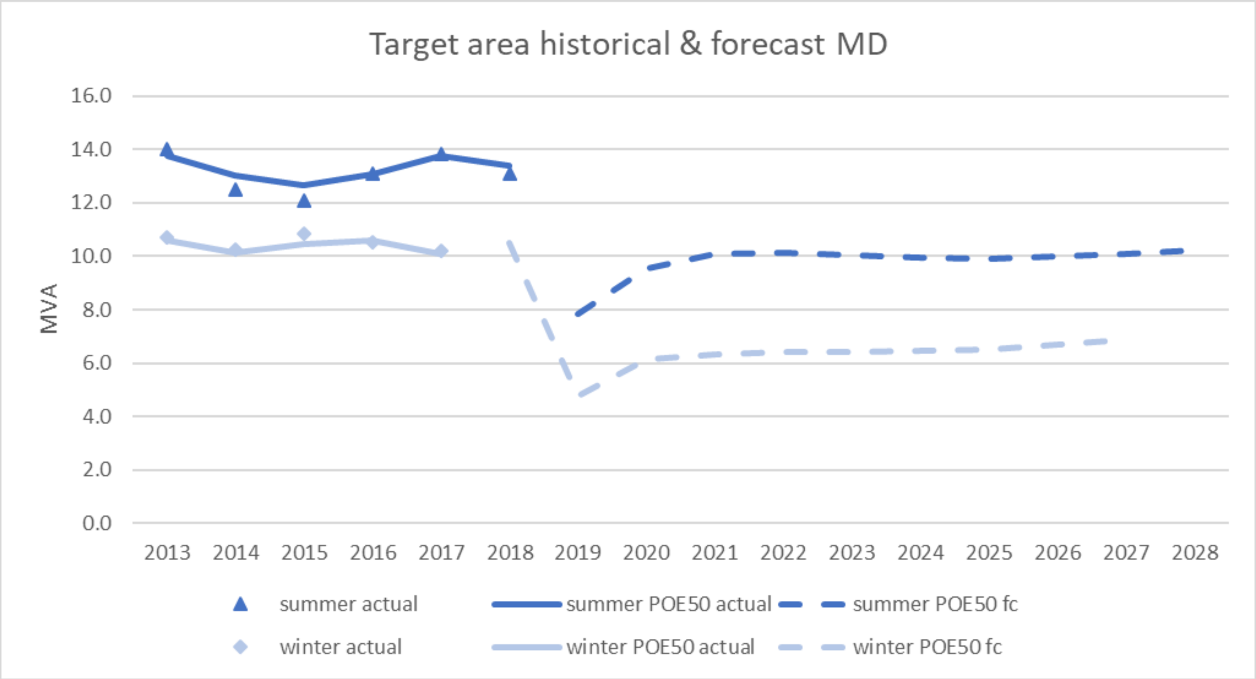
In summer 2017/18, Mascot zone substation maximum demand was 47.3 MVA, which occurred at 1:15pm AEDT on 20 December 2017. The summer weather corrected POE50 maximum demand was 48.2 MVA. The power factor at the time of summer maximum demand was 0.93. The forecast includes a transfer of around 25MVA to nearby Green Square zone substation to assist in mitigating some of the risks associated with the aged assets at Mascot zone substation. All the figures and analysis results presented in this NNOR have taken this transfer into account; the risk remains at Mascot zone substation post-transfer.

Mascot maximum demand is forecast to reach 36.2 MVA by summer 2022/23, with load growth in the near term from new customer loads expected to be connected in the area. Compared to the summer 2017/18 actual, this is a change of roughly -23% principally due to the bulk load transfer mentioned above.

6.3.7.1 Target Area maximum demand forecast

As noted above, Ausgrid does not have a specific forecast for the target area. However, a proxy forecast can be derived by scaling the overall Mascot zone substation POE50 maximum demand forecast shown in Figure 6.10 above to the target area maximum demand. This is shown in Figure 6.11 following.

Figure 6.11: Target area POE50 maximum demand forecast



The existing summer peaking characteristic shown in Figure 6.6 and the summer and winter daily load profiles of Figure 6.7 and Figure 6.8 respectively are considered applicable for future years, scaled appropriately.

6.4 Required demand management characteristics

A viable demand management solution must be technically feasible and provide reductions in electricity demand during peak and non-peak periods to reduce the level of expected unserved energy and do this in a cost-effective manner. Since deferral of the proposed supply side solution provides an economic benefit based on discounted cashflow analysis, deferral of the proposed supply side solution is possible when the cost of delivering the required demand reductions does not exceed the available budget for delivering those reductions for a given deferral scenario.

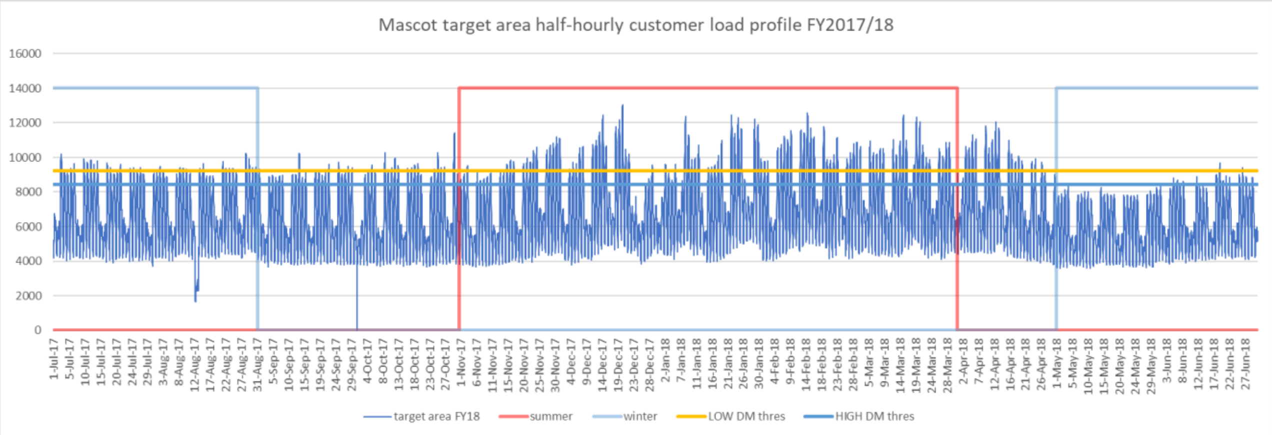
While it is not possible at this early stage to prescribe an exact mix of demand management initiatives that would form part of a solution package, Ausgrid considers the following guidelines would apply:

- As described in section 6.2, Ausgrid is seeking demand reductions from the target area to provide the highest effectiveness in reducing the unserved energy risk associated with the identified need at Mascot zone substation. At this stage, Ausgrid is targeting an unserved energy risk reduction in the range of 40% to 85%.
- A portfolio of non-network initiatives, comprising a mix of both permanent and temporary solutions, rather than a single solution, may be required. By temporary we mean that a particular initiative would be deployed for the timeframe it is required and then removed when no longer needed; for example, a temporary generator. By permanent we mean that a particular initiative would be installed and remain in place over its applicable lifetime; for example, installing energy efficient equipment or installing PV panels on a customer's premises.
- Non-network solutions that are dispatchable, such as temporary generators, should be available for a continuous period of up to 408 hours (equipment repair time) and year-round. The extent to which temporary generation may be called upon during this availability window (dispatched) is uncertain and dependent on the level of permanent demand reductions that can be achieved in the DM solutions mix.
- The demand profile of the target area is dominated by commercial loads. Non-network solutions aimed at reducing energy consumption from the electricity grid over a large number of hours of the day, especially if those hours coincide with normal business operating hours such as energy efficient lighting or solar PV, would provide material demand reductions for the target area.

- Non-network solutions targeted at reducing residential customer peak demand only may be of value, however, this would be dependent on the extent of permanent demand reductions that can be achieved and the hours of the day these reductions can be realised.
- A sizeable amount of demand reductions is required to successfully defer the proposed supply solution at Mascot (see Table 6.4). **However, it is not a requirement that individual proposals address the entire need**. Ausgrid welcomes cost-effective **partial** solutions that would allow us to construct a demand reductions portfolio that would achieve a least cost solution overall.
- Due to the required amount of demand reductions, sufficient time to “build up” the demand reductions may be required. Ausgrid is willing to consider contracting for demand reductions in the years prior to the 2022/23 need year to manage load at risk.

The above demand management characteristics are summarised in Figures 6.12 to 6.20 below. Figure 6.12 below shows the entire FY2017/18 target area customer demand profile, with summer and winter periods indicated and the curtailed load levels corresponding to “low DM” and “high DM” scenarios as described below. The “low DM” and “high DM” thresholds are based on post-DM flat (constant) load levels for the entire year, principally to make the analysis more straightforward. These load levels correspond to unserved energy risk reductions of around 40% and 85% respectively which is a result of the cost-benefit analysis underpinning the information presented in this report.

Figure 6.12: FY2017/18 under an assumed mix of PV, EE and temporary generation



Sections 6.4.1, 6.4.2 and 6.4.3 below provides illustrative target area load curves over 17-day periods (equipment repair window) in summer, winter and spring/autumn seasons, under 3 cases representing different levels of permanent DM and, as a result, the required level of temporary DM. The curves show the 17-day period where the highest number of hours of temporary DM is required per season.

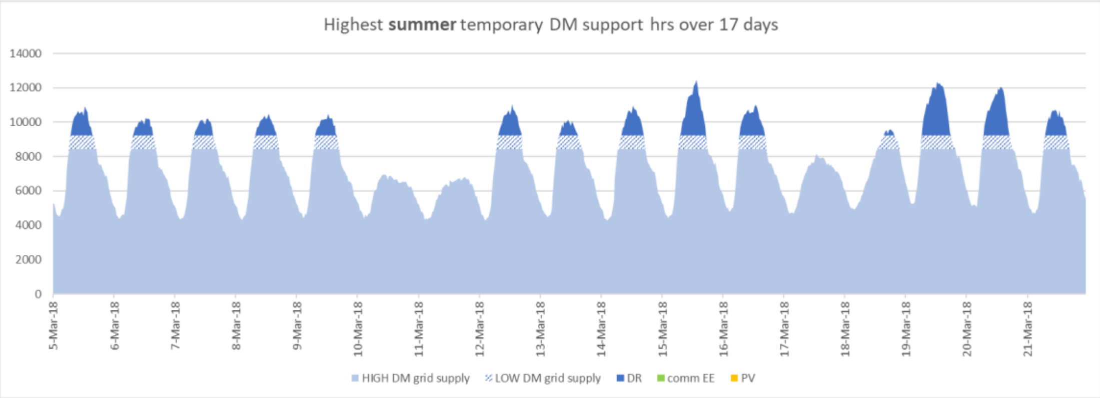
We emphasize that these charts illustrate hypothetical scenarios only, based on an assumed mix of temporary and permanent DM. The scenarios were chosen to illustrate how various DM portfolios might look and should not be interpreted as an exhaustive or prescriptive list of the types of solutions Ausgrid is seeking. Ausgrid welcomes and will consider all types of solutions that will enable us to cost-effectively defer the proposed supply-side solution at Mascot.

6.4.1 Case 1: Zero permanent DM

Figures 6.13, 6.14 and 6.15 below show 17-day periods in summer, winter and spring/autumn, based on the following assumed mix of permanent and temporary DM:

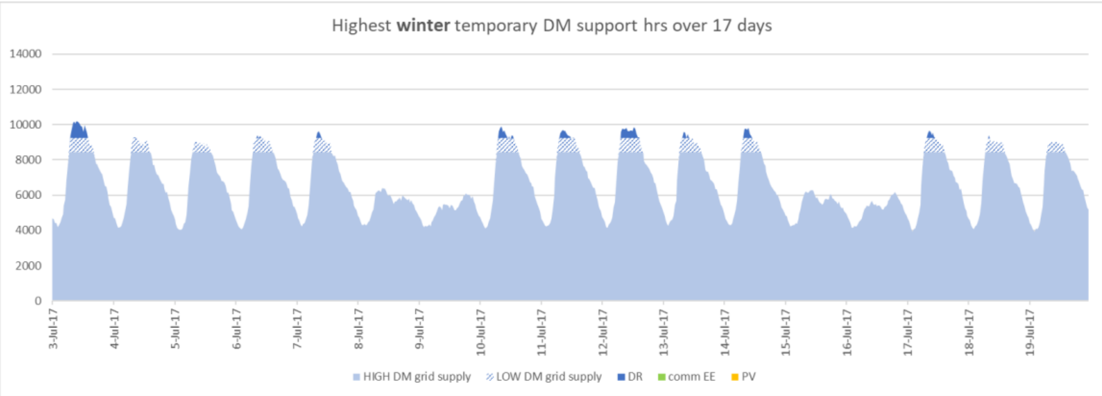
- Zero permanent DM, and
- Temporary DM (dark blue) is then used to curtail remaining load to the “low DM” and “high DM” load levels.

Figure 6.13: Highest 17 day summer period for temporary DM under assumption of zero permanent DM



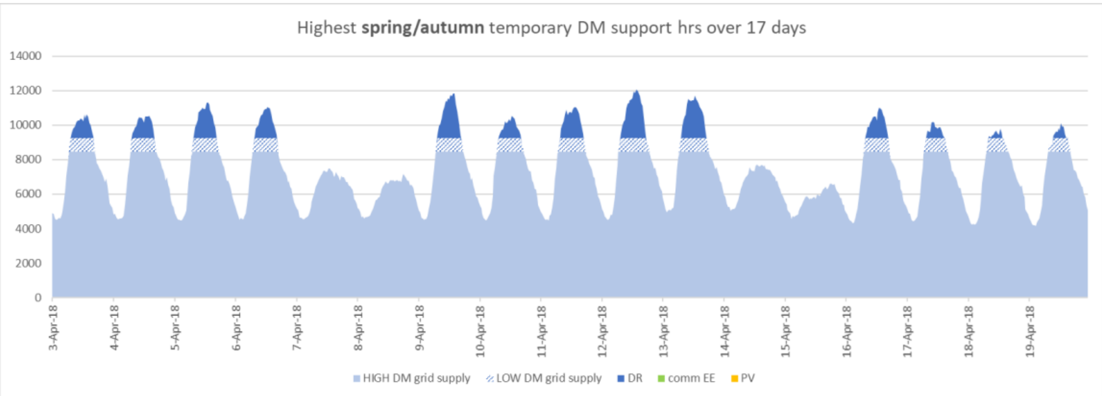
Over this 17-day period, temporary DM is required for an average of 7.5 to 9.5 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.14: Highest 17 day winter period for temporary DM under assumption of zero permanent DM



Over this 17-day period, temporary DM is required for an average of 3 to 6.5 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.15: Highest 17 day spring/autumn period for temporary DM under assumption of zero permanent DM



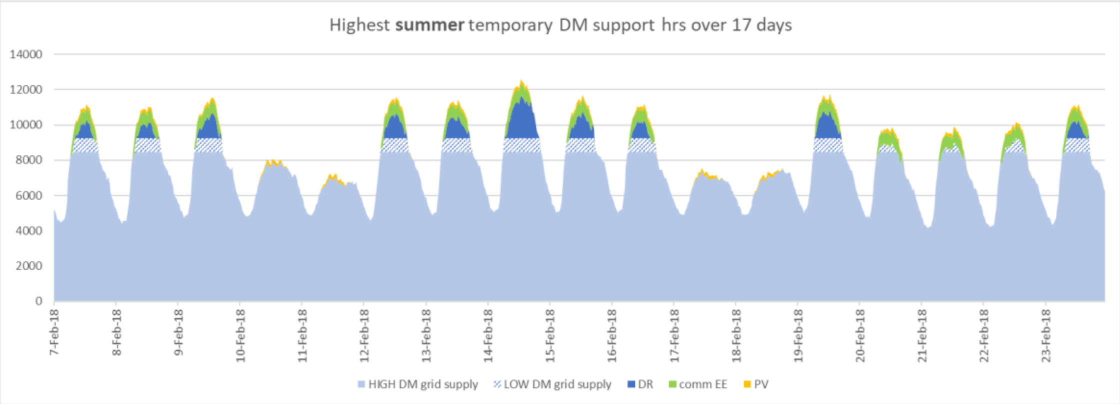
Over this 17-day period, temporary DM is required for an average of 6.5 to 8 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

6.4.2 Case 2: Moderate level of permanent DM

Figures 6.16, 6.17 and 6.18 below show 17-day periods in summer, winter and spring/autumn, based on the following assumed mix of permanent and temporary DM:

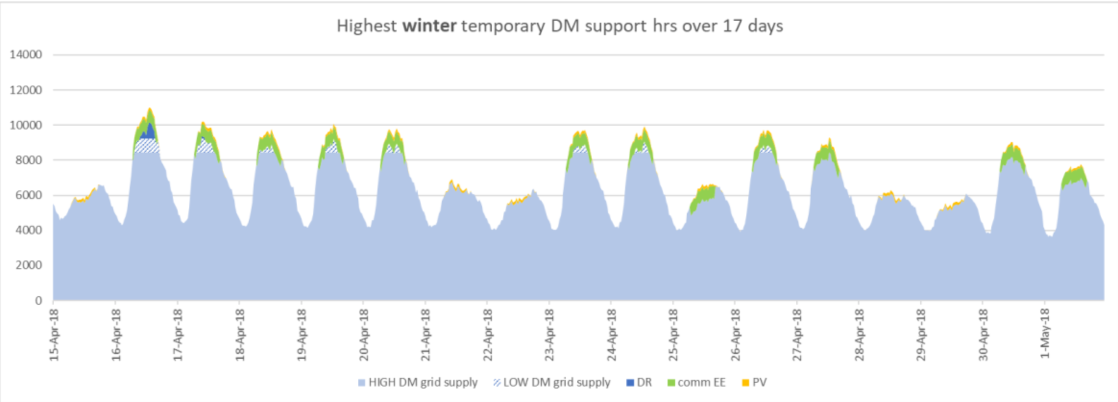
- Total of 1 MW of permanent DM, assumed to be installed PV and EE capacity (yellow and green respectively), of which 30% is PV. EE is assumed to be energy efficient lighting installed on commercial premises that provides demand reductions only on working days between 8am and 5pm,
- Temporary DM (dark blue) is then used to curtail remaining load to the “low DM” and “high DM” load levels.

Figure 6.16: Highest 17 day summer period for temporary DM under assumption of moderate permanent DM



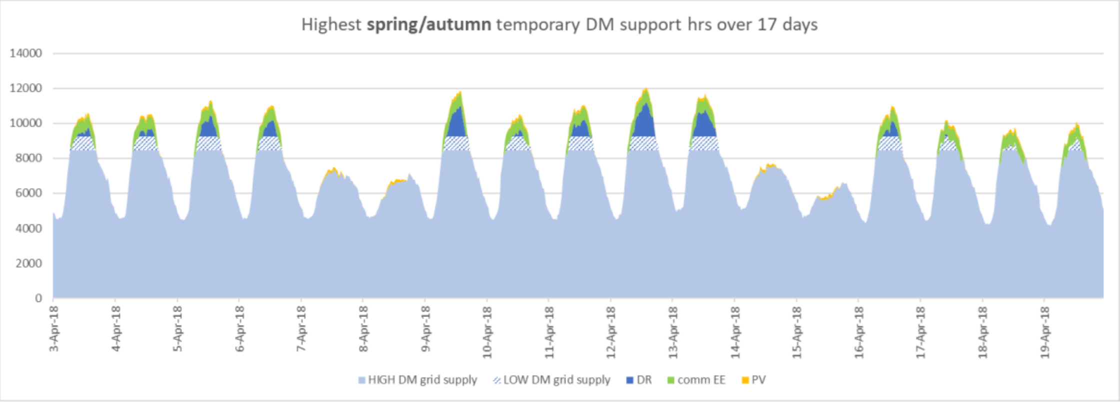
Over this 17-day period, temporary DM is required for an average of 5.5 to 8 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.17: Highest 17 day winter period for temporary DM under assumption of moderate permanent DM



Over this 17-day period, temporary DM is required for an average of 0.5 to 3 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.18: Highest 17 day spring/autumn period for temporary DM under assumption of moderate permanent DM



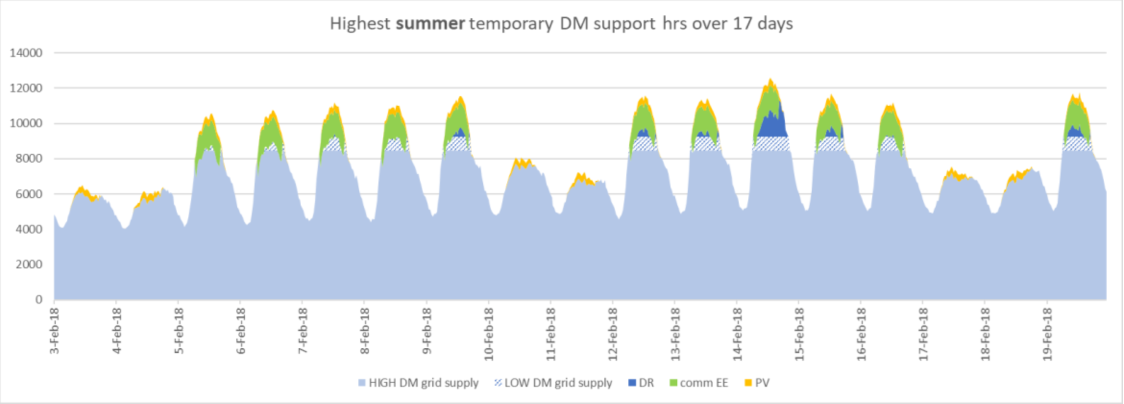
Over this 17-day period, temporary DM is required for an average of 4.5 to 7 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

6.4.3 Case 3: High level of permanent DM

Figures 6.19, 6.20 and 6.21 below show 17-day periods in summer, winter and spring/autumn, based on the following assumed mix of permanent and temporary DM:

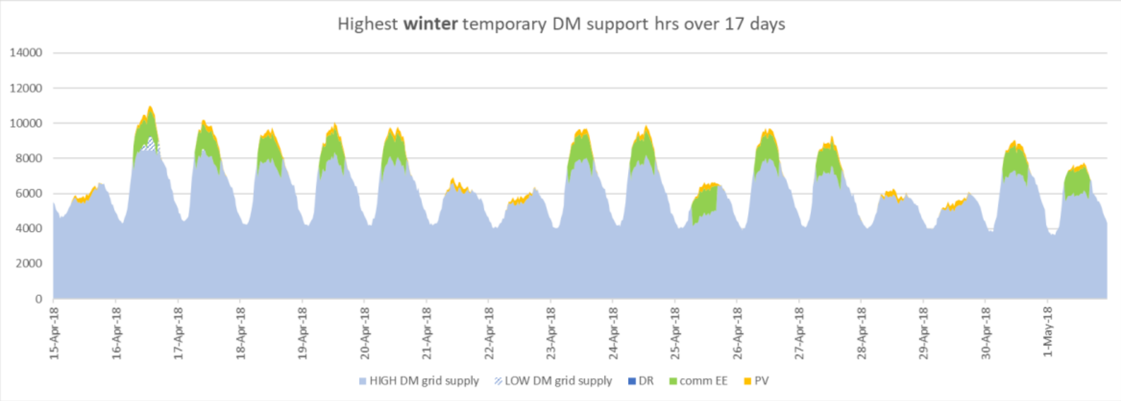
- Total of 2 MW of permanent DM, assumed to be installed PV and EE capacity (yellow and green respectively), of which 30% is PV. EE is assumed to be energy efficient lighting installed on commercial premises that provides demand reductions only on working days between 8am and 5pm,
- Temporary DM (dark blue) is then used to curtail remaining load to the “low DM” and “high DM” load levels.

Figure 6.19: Highest 17 day summer period for temporary DM under assumption of high permanent DM



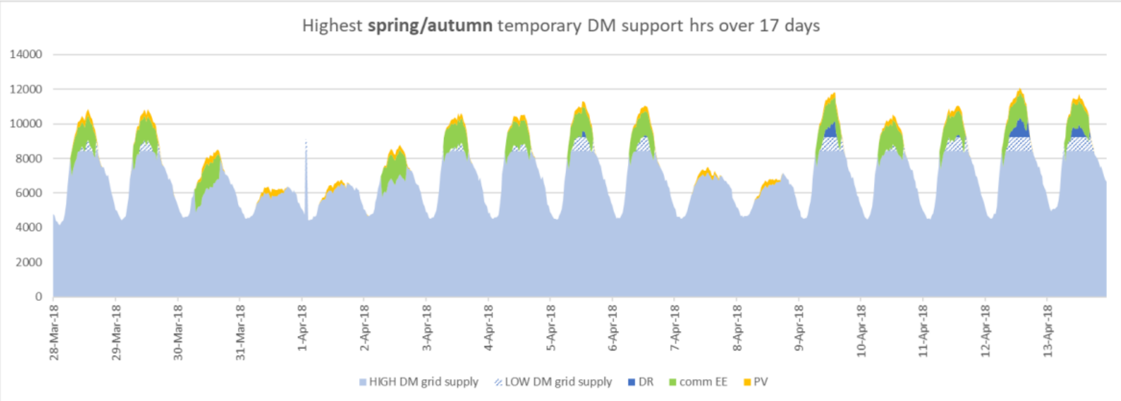
Over this 17-day period, temporary DM is required for an average of 3 to 6.5 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.20: Highest 17 day winter period for temporary DM under assumption of high permanent DM



Over this 17-day period, temporary DM is required for an average of 0 to 0.5 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

Figure 6.21: Highest 17 day spring/autumn period for temporary DM under assumption of high permanent DM



Over this 17-day period, temporary DM is required for an average of 1.5 to 5 hrs per day to curtail customer demand to the “low DM” and “high DM” thresholds, respectively.

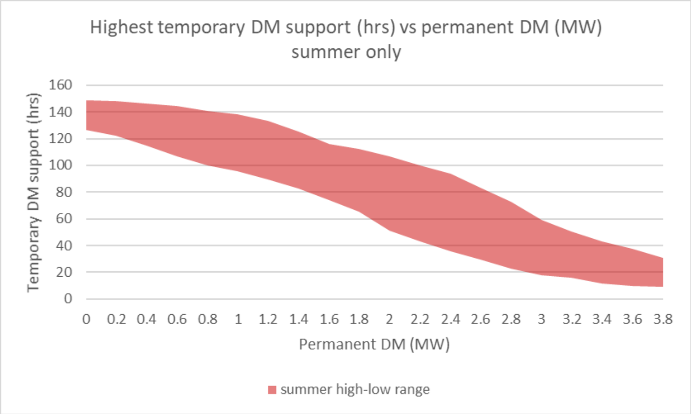
6.5 Temporary DM vs Permanent DM

Temporary DM solutions such as temporary generators, demand response and other forms of non-permanent demand reductions are likely to form part of a cost-effective DM portfolio.

The failure of one or more switchgear groups at Mascot zone may require up to 408 hours, or 17 days, to carry out repairs. Temporary DM solutions that have an **availability** component, such as temporary generators, should allow for availability based on the scenarios presented in Sections 6.4.1, 6.4.2 and 6.4.3, which include charts illustrating the required level of temporary DM support under 3 cases representing the level of permanent DM.

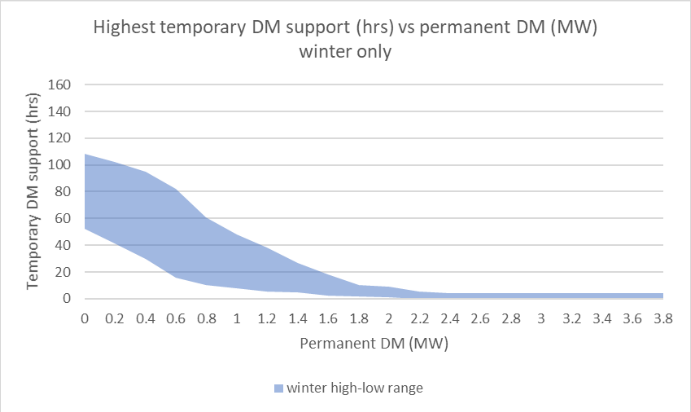
Actual hours of support (as opposed to availability) are uncertain and dependent on a range of factors such as the customer load profile, the time of year, the cost of various DM solutions and the level of permanent DM that can be achieved. The level of temporary DM required is dependent on the level of permanent DM that can be achieve, assuming the permanent solutions are cost-effective. To provide some guidance, Figures 6.22, 6.23 and 6.24 below show the relationship between required temporary DM support as a function of permanent DM. Figures 6.22, 6.23 and 6.24 each show a range representing the highest number of hours of required temporary DM support over a 17-day period, calculated based on the target area load profile in FY2017/18. The range shows the required level of load curtailment corresponding to the “low DM” and “high DM” load thresholds presented in Section 6.4,

Figure 6.22: Required hours of temporary DM support as a function of permanent DM in summer



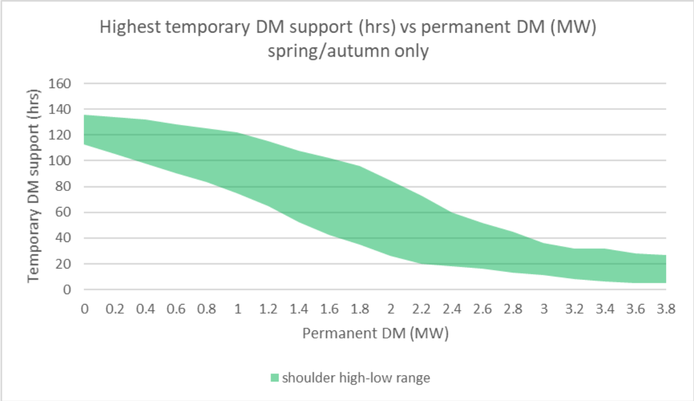
For zero permanent DM, temporary DM support in summer may be required for up to 150 hours. This decreases to around 10 hours under a scenario of high permanent DM.

Figure 6.23: Required hours of temporary DM support as a function of permanent DM in winter



For zero permanent DM, temporary DM support in winter may be required for up to 110 hours. This decreases to zero under a scenario of high permanent DM.

Figure 6.24: Required hours of temporary DM support as a function of permanent DM in spring/autumn



For zero permanent DM, temporary DM support in spring/autumn may be required for up to 135 hours. This decreases to around 5 hours under a scenario of high permanent DM.

6.6 Available demand management funds

This section sets out the funds that Ausgrid has determined are available in the form of incentive payments for non-network initiatives to address the identified network need.

The funds available for non-network solutions have been determined by Ausgrid based on technical and financial modelling of the likely costs and benefits of implementing non-network solutions to defer capital expenditure. The net present value of all costs and benefits associated with deferring the proposed network solution for either 1, 2 or 3 years is compared against the base case (without deferral). In this instance, the base case involves the establishment of new 132/11kV zone substation on an alternative site in the Mascot area by 2022/23, with an estimated cost of $38 million in real 2018/19 dollars.

Due to the uncertainty associated with a range of factors such as the level of demand reductions that are achievable, the composition of the DM solutions mix, the cost of individual solutions and the rate at which demand reductions can be realized over time, and other factors, the funds available for non-network solutions at this early stage is presented as a range, with lower and upper bounds based on Ausgrid cost-benefit analysis based principally on NPV. The deferral cases include an option value benefit in the assessment where for every year of deferral, the capital cost of the supply-side solution decreases by 5%.

The funds available for DM solutions is provided below (see also Table 6.4 below). The figures are presented as a range and expressed in present value dollars due to uncertainty in factors such as the magnitude of DM solutions that can be achieved and the time required to "build up" demand reductions:

- For a 1 year deferral, DM funds available of $1.0m to 3.0m,
- For a 2 year deferral, DM funds available of $1.1m to 3.8m, and
- For a 3 year deferral, DM funds available of $1.6m to 4.0m.

The range of DM funds is based on Ausgrid modelling of unserved energy risk reduction in 2022/23:

- At the low end, around 40% unserved energy risk reduction for a 1 year deferral, and
- At the high end, around 85% unserved energy risk reduction for a 3 year deferral.

It is within this 40-85% range of unserved energy risk reduction that Ausgrid considers a DM solution would be viable at Mascot.

The demand reductions required for each year of deferral and funds available is based on cost-benefit assessment which relies on a range of analysis inputs such as the current demand forecast, customer load profile, the cost and timing of the proposed supply-side solution, the modelled benefits of reducing customer demand, a target area defined based on a future connectivity state of the Mascot 11kV network, discount rate, preliminary estimated costs of an assumed mix of permanent and temporary demand reductions as well as a forecast of how these are projected to change over time, and others. The inputs are subject to change and any changes to these inputs may affect the required demand reductions and/or the funds available. Any changes impacting on demand reductions and/or available funds will be negotiated with project proponent(s) at a later stage if required.

6.7 Summary of demand management requirements

The identified need at Mascot zone substation relates to the outage of one or more 11kV switchgear groups. Such an event, although unlikely, would, on average, result in the loss of supply to around 20% of the customer load at Mascot for an extended period of time. Due to the magnitude of customer load potentially unserved, a portfolio of demand reductions is needed to address both demand (MW) and energy volume (MWh) components.

The Mascot demand management requirements are set out in Table 6.4 below:

a) The funds available for DM are as described in section 6.6: "Available demand management funds",

b) The indicative DM requirements are given as the estimated duration, volume and peak demand reductions required from demand reductions in total (permanent and temporary). They are the same for 1, 2 and 3 years of deferral due to the relatively flat demand forecast around 2022/23 for the Mascot target area, as shown in Figure 6.11, and presented as ranges corresponding to the "low DM" and "high DM" scenarios, as per Section 6.4.

Table 6.4 – Target area demand management requirements and available funds

To defer supply solution by:	DM req'd in:	DM funds[a] (present value $m)	Indicative demand management requirements[b]								
			Duration of permanent & temporary DM required over 408hr window (hours)			Volume of permanent & temporary DM required over 408hr window (MWh)			Peak reduction (MW)		
			2022/23	2023/24	2024/25	2022/23	2023/24	2024/25	2022/23	2023/24	2024/25
1 year	2022/23	1.0 to 3.0	125 to 150	-	-	170 to 275	-	-	3 to 5	-	-
2 years	2023/24	1.1 to 3.8	125 to 150	125 to 150	-	170 to 275	170 to 275	-	3 to 5	3 to 5	-
3 years	2024/25	1.6 to 4.0	125 to 150	125 to 150	125 to 150	170 to 275	170 to 275	170 to 275	3 to 5	3 to 5	3 to 5

Ausgrid is willing to consider contracting for demand reductions in the years prior to the 2022/23 need year to manage load at risk.

6.8 Connection of embedded generators

In order to substitute for traditional "poles and wires" investment in the electricity grid, embedded generators must be capable of safely and reliably delivering electricity under a range of conditions.

Proposals that include embedded generators, which include temporary generators such as diesel generators and permanently connected generators such as rooftop PV, will be required to comply with the Ausgrid requirements of connecting an embedded generation system.

Proponents should familiarise themselves with these requirements, which cover:

- Ausgrid's connection policy,
- Guidelines and process for connection,
- Relevant network standards,
- Relevant application forms.

Link:

https://www.ausgrid.com.au/Connections/solar-battery-and-embedded-generation

6.9 Attachments

Ausgrid provides the following materials to assist proponents and interested parties in developing demand management proposals.

- Google Earth KMZ file indicating target area,

- Excel file containing data underpinning Load Duration Curve, interval data, forecasts

- List of customers in target area,

7 Submissions

7.1 Invitation for submissions

Ausgrid seeks submissions from interested parties, especially proponents of non-network solutions. Ausgrid welcomes cost-effective partial solutions and we emphasize that individual proposals need not address the entire need.

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 do need further information, please contact us as early as possible, to ensure that sufficient time is available to fully assess feasible network and non-network potential solutions. It is essential that alternatives to network solutions are presented by proponents in sufficient time to allow for their evaluation and any necessary clarifications with proponent/s.

All enquiries should be made in writing and directed to:

Demand Management Planning & Investigations Manager

Email: demandmanagement@ausgrid.com.au

Submissions should be lodged with us on or before **23 Dec 2019** (3 month consultation period).

A separate FAQ document will be published alongside the NNOR. All submitted questions (anonymised) and their responses will be published in this FAQ. Proponents are encouraged to regularly check this FAQ document as it will be updated regularly.

7.2 Information from non-network proponents

To be considered a feasible option, any demand management solution must be technically feasible, commercially feasible and able to be implemented in sufficient time for deferral of the network investment. In the absence of any viable demand management solutions, the preferred network solution is to be commissioned by summer 2022/23.

Due to the long consultation timeframe and to avoid delays in releasing information (this document) to the market, Ausgrid will develop in parallel a separate Request for Proposals (RFP) document that will formally request detailed submissions from the market via a formal procurement process. We have chosen not to combine an RFP document with this options report as we believe collaborative discussions with potential market providers following publication of this report would be beneficial prior to the initiation of a formal tendering process.

Ausgrid is seeking demand management proposals that provide sufficient detail about the type and likely scale of non-network solutions offered by market providers. Respondents are not required to provide detailed costing of proposed solutions in response to this report, however, proposals should include as much information as possible.

1. Proponent name and contact details;

2. Overview of the extent to which the proposal addresses the identified need;

3. A technical description of the proposal, including:

- Location/s, in particular if the demand reductions and/or temporary generation are contained within the target area;
- For load reductions, provide details about scale such as:
    - Type of solution (eg energy efficient lighting, residential demand response etc),
    - Installed capacity,
    - Level of demand reductions including any standards and/or methodologies relied upon to determine the load reductions,
    - An estimate of projected customer uptake, if relevant,
- For additional supply (temporary or permanently connected generators);

- Network connection requirements, if needed;
- Contribution to power system security or reliability (if known);
- Contribution to power system fault levels, load flows and stability studies (if applicable);
- The operating profile;
- How each of these matters is consistent with the applicable technical standards;

4. Timing of delivery of solution and its estimated lifespan;

5. Proposed operational and/or contractual commitments, including financier commitments;

6. Planning application information, where required.;

7. Salvage and removal costs; and

8. An evaluation of potential risks associated with the proposal, including a comparison with the risks associated with the preferred network augmentation option, and any actions that can be taken to mitigate these risks. This assessment should address the risk of not meeting the demand requirement and the compensation arrangements that would apply in such circumstances.

We will review each non-network option and we may seek further information from the non-network proponent to better understand the design of the proposed solution and its implications on the network and other network users.

7.3 Next steps

As outlined in Section 1, this report is being prepared under the RIT-D consultation procedures, to assist interested parties in identifying potential non-network options to address the identified need in the Mascot supply area.

Following consideration of submissions made in response to this Non-Network Options Report, Ausgrid will proceed to prepare a Draft Project Assessment Report. That report will present a detailed assessment of all options to address the identified need, plus a summary and commentary on the submissions to this report. The Draft Project Assessment Report will apply the latest available information on demand forecasts, VCR estimates and project cost estimates.

We intend to publish the Draft Project Assessment Report in early 2020 oncew we have completed our assessment. Further consultation, in accordance with the RIT-D process set out in the Rules, will then proceed.

Due to the lengthy timeframe required for consultation and to avoid delays in releasing information (this document) to the market, Ausgrid will develop in parallel a separate Request for Proposals (RFP) document that will formally request detailed submissions from the market via a formal procurement process. It is anticpated that this RFP will be uploaded to a procurement platform such as Tenderlink or Ariba.

Glossary

AEMO	Australian Energy Market Operator
AEMC	The Australian Energy Market Commission is the rule maker and developer for Australian energy markets
AER	Australian Energy Regulator
Amperes (A)	Refers to a unit of measurement for the current flowing through an electrical circuit. Also referred to as Amps.
Constraint	Refers to a constraint on network power transfers that affects customer service.
Continuous rating	the permissible maximum demand to which a conductor or cable may be loaded on a continuous basis.
DLF	Distribution Loss Factor
DNSP	A Distribution Network Service Provider who engages in the activity of owning, controlling, or operating a distribution system, such as Endeavour Energy, Ausgrid and Essential Energy
EUE	Expected Unserved Energy
GWH gigawatt hour	One GWh = 1000 megawatt hours or one million kilowatt hours
HV high voltage	Consists of 11kV and 22kV distribution assets
LV low voltage	Consists of 400V and 230V distribution assets
KV kilovolt	One kV = 1000 volts
kW kilowatt	One kW = 1000 watts
KWh Kilowatt hour	The standard unit of energy which represents the consumption of electrical energy at the rate of one kilowatt for one hour
MD	Maximum Demand. The highest amount of electrical power delivered (or forecast to be delivered) for a particular season (summer and/or winter) and year.
MVA	(unit of electrical power) Mega Volt Amp.
MVAr	MVA (reactive). Where quoted as part of a demand forecast, it is assumed that capacitors are in service.
MW megawatt	One MW = 1000 kW or one million watts
MWh megawatt hour	One MWh = 1000 kilowatt hours
Network	Refers to the 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.
N capacity	The capacity of a network (or sub-section of network) with all elements in service.
N-1 capacity	The capacity of a network (or sub-section of network) following a failure of a single critical element.
NEM	National Electricity Market
NER	National Electricity Rules
NPV	Net Present Value
POE 50	Probability of Exceedance. In this document, refers to a demand forecast with a 50% probability of being exceeded (i.e. 1 in 2 years)

pf	Power Factor
RIT-D	Regulatory Investment Test for Distribution. A test established and amended by the Australian Energy Regulator (AER) that establishes consistent, clear and efficient planning processes for distribution network investments over a certain limit ($6m), in the National Electricity Market (NEM).
Reliability of supply	The measure of the ability of the distribution system to provide supply to customers.
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
STS	Sub-transmission Substation
Sub-transmission	Any part of the power system which operates to deliver electricity from the higher voltage transmission system to the distribution network and which may form part of the distribution network, including zone substations
Sub-transmission system	Consists of 132kV, 66kV and 33kV assets, including dual function assets
System normal	The condition where no network assets are under maintenance or forced outage, and the network is operating according to normal daily network operation practices.
V volt	A volt is the unit of potential or electrical pressure
VCB	Vacuum Circuit Breaker
VCR	Value of Customer Reliability
W watt	A measurement of the power present when a current of one ampere flows under a potential of one volt
XLPE	Cross-linked Polyethylene
ZS	Zone Substation

Ausgrid