Addressing reliability requirements in the Tarro load area

NOTICE ON SCREENING FOR NON-NETWORK OPTIONS

4 November 2022

Ausgrid

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1 Introduction

Tarro zone substation (ZS) is located at the eastern end of the Maitland network area and was commissioned in 1957. It is bound to the west and south by the green corridor that joins the Hunter River to the Watagans National Park. It is supplied by two 33kV feeders from Beresfield Subtransmission Substation (STS) and equipped with two groups of 11kV compound-insulated switchgear in a double busbar arrangement.

The 11kV distribution network supplies nearby residential areas (in Tarro, Woodberry and Beresfield), light industrial and commercial developments in Beresfield and one large customer: Baiada (formerly Steggles), which is involved in the manufacturing of poultry products. The recent growth in Beresfield is attributed to the transport infrastructure in the area, with direct access to Sydney, Tamworth (inland) and Brisbane (coast) provided by the intersection of the M1 Motorway, New England Highway and Pacific Highway. There is also direct access to Newcastle Ports via the railway network. It currently supplies approximately 4,000 customers.

The existing 11kV switchgear at Tarro ZS remains original and is a Westinghouse/Email HQ type with compound insulation. The existing 11kV switchgear at Tarro ZS has increasing condition, reliability and safety concerns. It is approaching the point at which the community benefits of switchgear replacement exceed the costs.

Ausgrid has initiated this RIT-D to replace the 11kV switchgear at Tarro ZS in order to identify a preferred option that would ensure Ausgrid is able to satisfy its reliability and performance standards in supplying the Tarro load area.

No exemptions listed in the NER clause 5.17.3(a) apply and therefore Ausgrid is required to apply the RIT-D to this project.

This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ausgrid's determination that no SAPS and non-network option forms all or a significant part of any potential credible option for this RIT-D. It sets out the reasons for Ausgrid's determination, including the methodologies and assumptions used. A full discussion of asset conditions and the identified need can be found in the Final Project Assessment Report (DPAR).

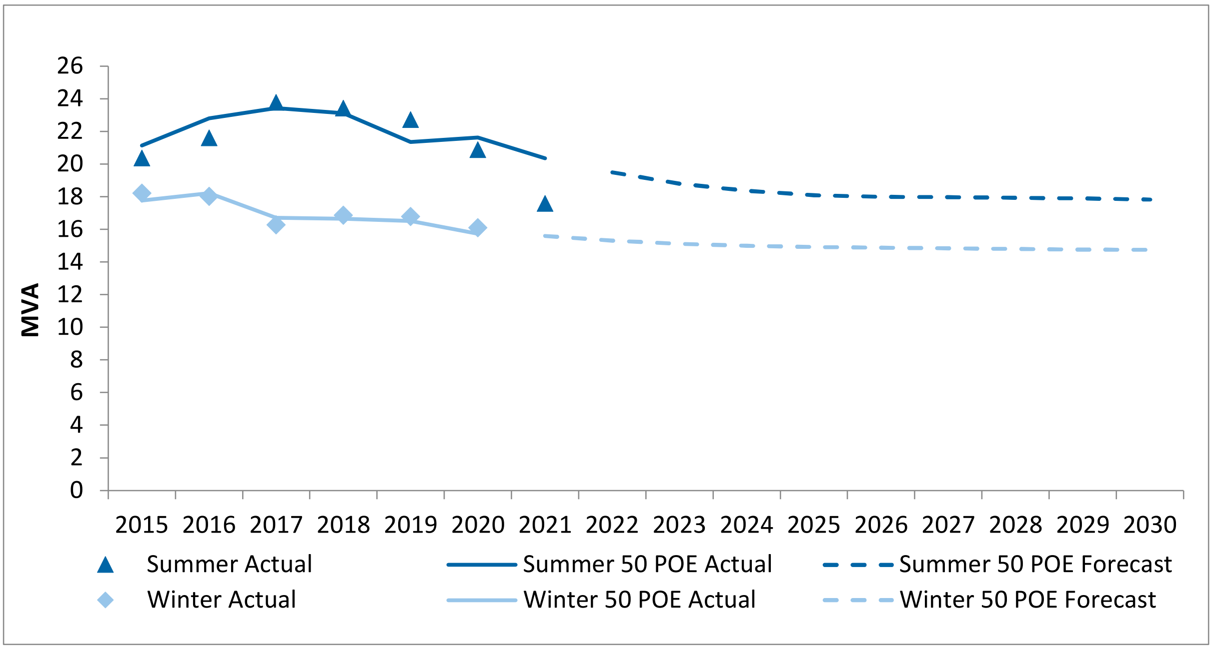
2 Forecast load and capacity

2.1 Demand forecast

Figure 1**Error! Reference source not found.** below shows the historical actual demand, the 50% Probability of Exceedance level (50 POE) weather corrected historical actual demand and the 50 POE forecast demand in both winter and summer at Tarro ZS.

Tarro ZS has a total capacity of 47.6 MVA and a firm capacity of 23.8 MVA. In 2020/21, the maximum demand on the ZS was 17.6 MVA at 3:15pm AEDT on 17 December 2020. The weather corrected demand at the 50 POE level was 20.4 MVA. The power factor at the time of summer maximum demand was 0.95.

Figure 1: Demand forecast at Tarro

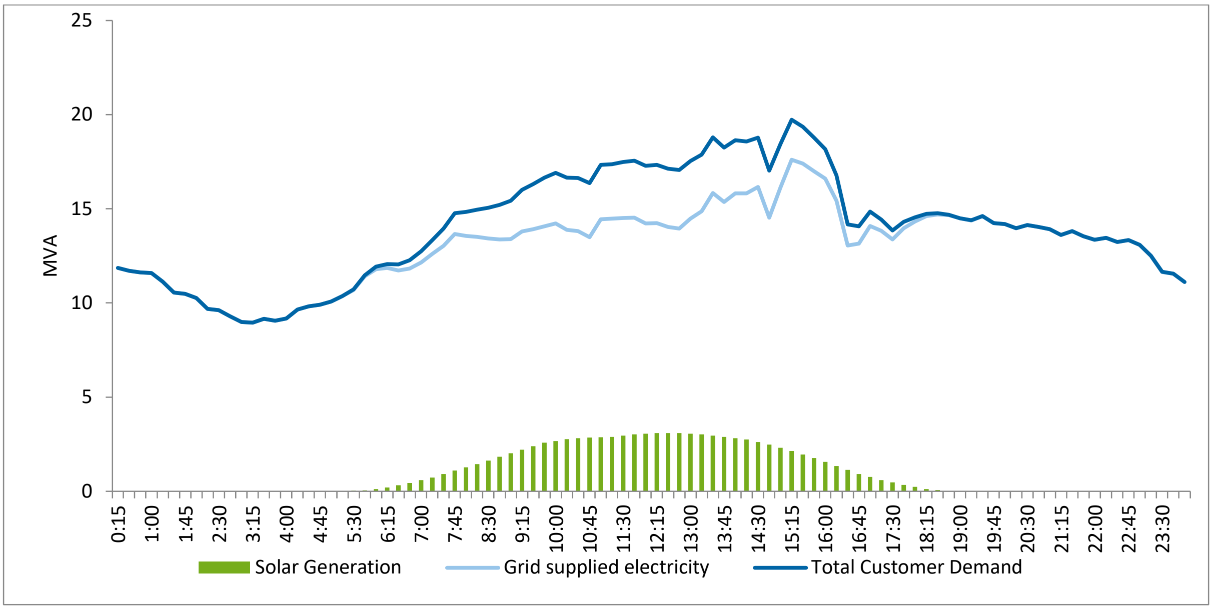


2.2 Pattern of use

Over the past 7 years, annual maximum demand at Tarro ZS has typically occurred in summer between 12:00 and 5:00pm AEDT.

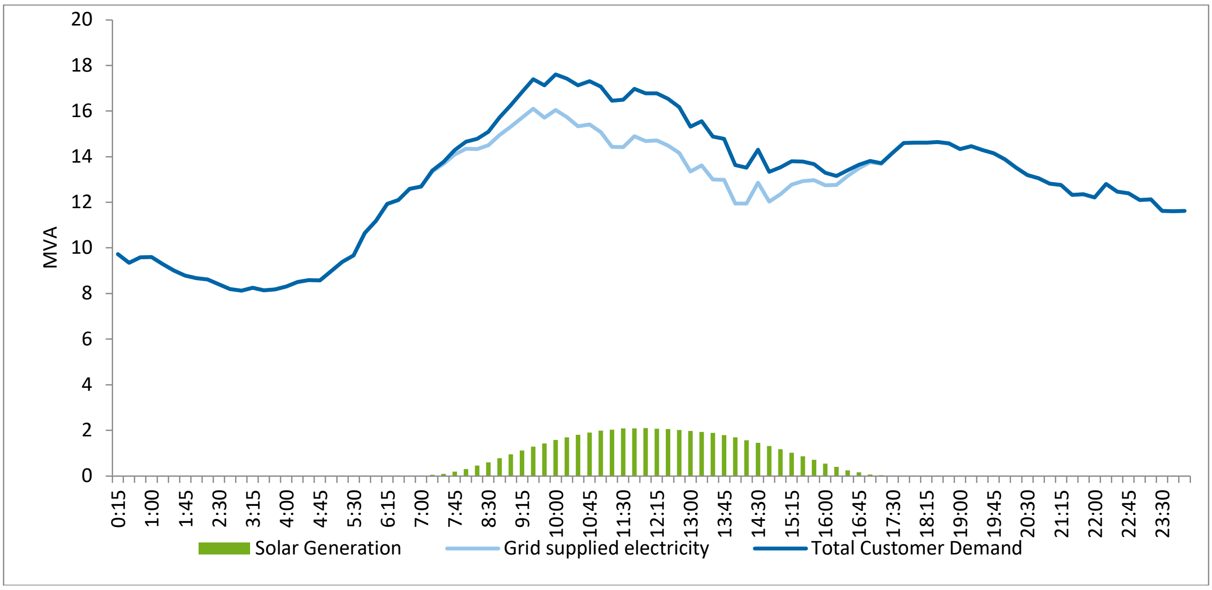
There is a total Solar PV capacity of approximately 4.7 MW connected to Tarro ZS. At the peak time of 3:15pm AEDT on 17 December 2020, these PV systems are estimated to have been generating 2.1 MW. Figure 2 below shows the load trace on this day including the contribution from customer solar power systems.

Figure 2: Summer peak day demand profile and PV contribution at Tarro on 17 December 2020



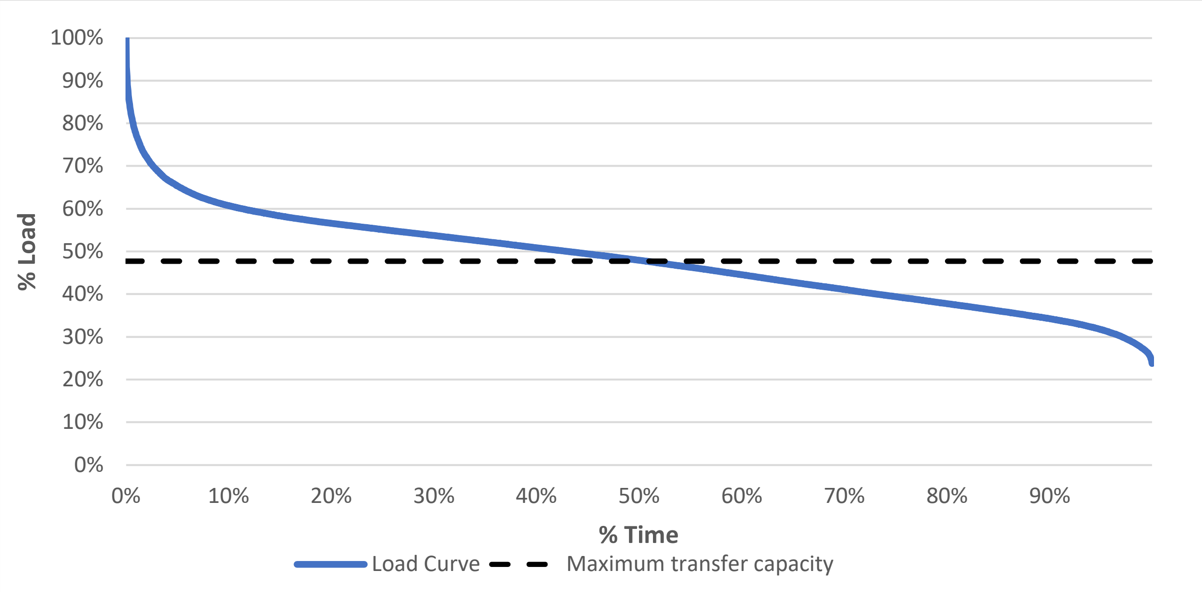
Over the past 7 years, the time of winter peak has typically occurred between 8:30 am and 12:00pm AEST. At the peak time of 6:00pm AEST on 10 August 2020, the estimated generation from PV systems is 1.28 MW. **Error! Reference source not found.** below shows the load profile for the peak demand day 10 August 2020 including the contribution from customer installed solar power systems.

Figure 3: Winter peak day demand profile and PV contribution at Tarro on 10 August 2020



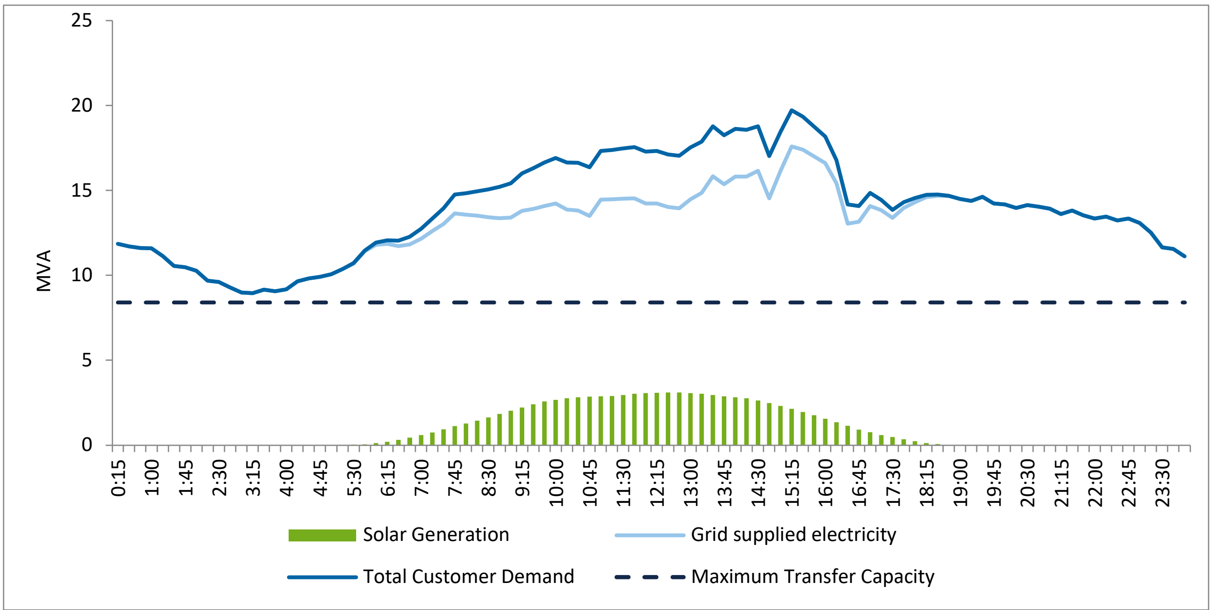
Tarro ZS currently has a load transfer capacity of 8.4 MVA or about 48% of the actual maximum 2020/21 summer demand and 52% of the actual maximum for winter 2020. The load duration curve including the load transfer capacity is shown in Figure 4.

Figure 4: Tarro load duration curve



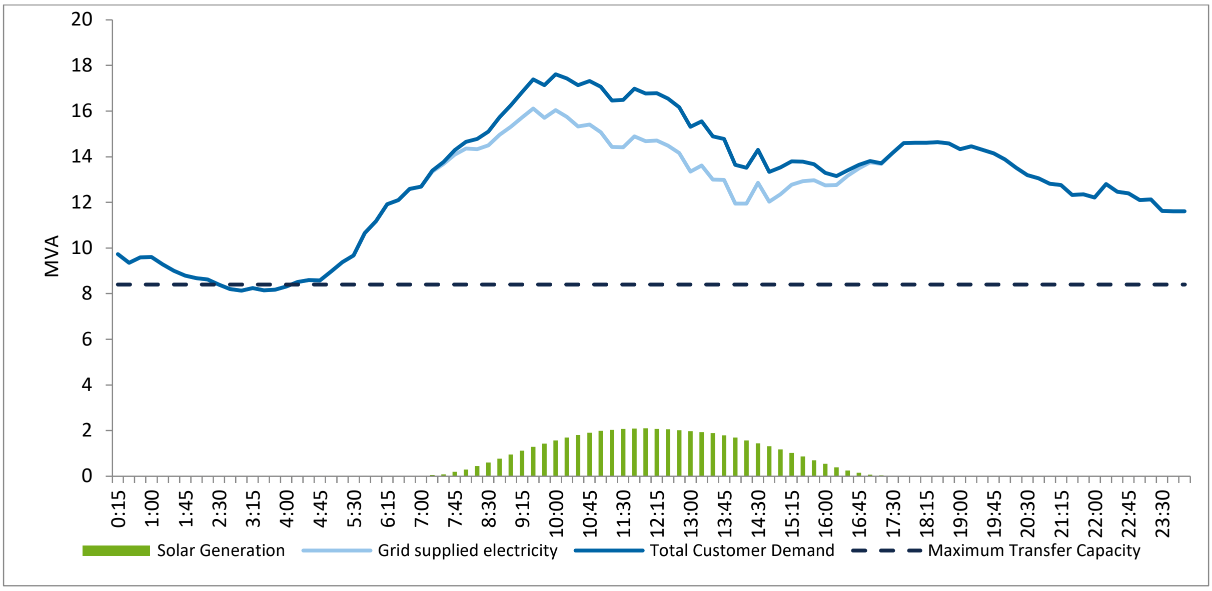
In the event of a network outage on the summer maximum demand day and following realisation of the maximum transfer capacity through network switching, there is a maximum shortfall of around 9.2 MVA. The shortfall would occur for most of the day as seen in Figure 5 below.

Figure 5: Summer maximum demand profile at Tarro on 17 Dec 2020



Similarly, for the winter peak demand day, the shortfall would also be for most of the day after realising the maximum load transfer capacity. The maximum shortfall would be around 7.7 MVA and there would be a shortfall for most of the day (see Figure 6).

Figure 6: Winter maximum demand profile at Tarro on 10 Aug 2020



2.3 Customer characteristics

Tarro ZS serve a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2020/21 period are as follows:

Table 1: Tarro customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	3,501	388	34	3,923
% of Customers	89.2%	9.9%	0.9%	
Annual Consumption (MWh)	22,906	7,142	54,378	84,426
% of Annual Consumption	27.1%	8.5%	64.4%	
Number of Solar Customers	826	29	3	858
% of Solar Customers	18.0%	10.4%	10.0%	
Average Annual Consumption (MWh)	7	18	1,599	22

About 92% of residential customers live in detached homes with an average usage of about 7.1 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.6 MWh per year.

3 Proposed preferred network option

This section provides details of credible options that Ausgrid has identified as part of its network planning activities to date. All costs in this section are in real $2021/22, unless otherwise stated.

Table 2: Summary of the credible options considered

Overview	Key components	Estimated capital cost (including decommissioning costs)
Option 1 – Replacement of the 11kV switchgear in a new switchroom and enabling works to add third 11kV switch group in future	• Installation of modular equipment room • Install 2 new sections of 11kV switchgear & switchboard • Connect existing transformers and 11kV circuits to the new switchgear • Disconnect & remove existing 11kV switchgear	$11.3 million
Option 2 – Construction of a new 33/11kV ZS to replace the existing Tarro ZS	• Install 2 x 33/11kV transformer units with equivalent 11kV switchroom. • Transfer loads from existing Tarro zone • Decommission the existing Tarro zone	$20.4 million

Ausgrid also considered an additional option that has not been progressed. The table below summarises Ausgrid's consideration and position on each of these potential options.

Table 3: Network options considered but not progressed

Option not progressed	Description	Reason why option was not progressed
Transferring a major load to the 33 kV network	Transferring a major load to the 33 kV network (at a capital cost of $5.6 million) so that it is no longer supplied by the Tarro ZS.	While this option is lower cost than Option 1, and reduces the expected unserved energy for the customer since it is no longer supplied from the Tarro ZS, there still remains significant unserved energy (from the remaining load connected to the Tarro ZS) as well as reactive maintenance costs and safety risks. This option is therefore not considered economically feasible.

Table 4: Summary of the three scenarios investigated

Variable	Scenario 1 - central	Scenario 2 – low benefits	Scenario 3 – high benefits
Demand	POE50	POE90	POE10
VCR	$56.15/kWh	$39.31/kWh	$73.00/kWh
Unplanned corrective maintenance cost	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Safety risk costs	Central estimates	70 per cent of the central estimates	130 per cent of the central estimates
Capital costs	Capital cost central estimates	125 per cent of capital cost estimate	75 per cent of capital cost estimate
Planned routine maintenance for new assets	Central estimates	125 per cent of the central estimates	75 per cent of the central estimates
Planned routine maintenance for existing assets	Central estimates	75 per cent of capital cost estimate	125 per cent of capital cost estimate
Decommissioning costs	Central estimates	125 per cent of capital cost estimate	75 per cent of the central estimate
Discount Rate	3.44%	5.50%	2.34%

Refer to the Final Project Assessment Report for further details about the options assessment methodology and scenario analysis.

3.1 Preferred option at this stage

Option 1 has been found to be the preferred option, which satisfies the RIT-D and provides a higher net market benefit than option 2. Option 1 involves replacement of the 11kV switchgear in a new 11kV switchroom building to be constructed at Tarro ZS. The proposed scope of works for Option 1 consists of:

- Installation of a Modular Equipment Room (MER) adjacent to the 33 kV switchgear;
- Installation of a new 11 kV switchboard including two sections of single bus switchgear and 13x11 kV circuit breakers;
- Installation of 11 kV connections to connect both existing main power transformers to the MER and transfer seven existing 11 kV feeders to the new switchboard;
- Construction of firewalls between transformer bays and on the western boundary to protect a residential property;
- Rearrangement of the 33 kV feeder connections and structures within the site to achieve safety clearances required for internal 11 kV cable work;
- Secondary systems upgrades; and
- Disconnect, dismantle and remove the existing 11 kV switchgear from the site.

Refer to the Final Project Assessment Report for this project for further details about the options assessment.

4 Assessment of SAPS and non-network solutions

4.1 Required demand management characteristics

As noted in Section 2, an outage originating from the 11kV switchgear may result in significant supply shortfall at Tarro ZS.

To be considered a feasible option, any demand management solution must be technically feasible, commercially feasible, and able to be implemented in sufficient time by 2024/25 for deferral of the network investment.

4.2 Available demand management funds

To identify the available funds for a possible demand management solution, Net Present Value (NPV) analysis was carried out and the net NPV for the network option is compared against the net NPV of deferral scenarios.

Table 6 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years.

Table 5: Required demand reduction and available funds at Tarro

Required peak demand reduction	Available demand management funds ($)		
	1 Yr deferral	2 Yr deferral	3 Yr deferral
5MVA*	$0.39m	$0.74m	$1.04m

*To be viable, DM solutions must materially reduce demand at times other than at peak due to the replacement driver. Available funds have been calculated accordingly.

- For a 1-year deferral, around 5MVA of demand reduction is required in 2024/25 with total available demand management funds of $0.39m, which is equivalent to $78/kVA/year,
- For 2-year deferral, 5MVA of demand reduction in 2024/25 and 2025/26 with total available demand management funds of $0.74m, which is equivalent to $74/kVA/year, and
- For 3-year deferral, 5MVA of demand reduction is required in 2024/25, 2025/26 and 2026/27 with total available demand management funds of $1.04m, equivalent to $69/kVA/year

The above figures already account for maximum load transfer capacity out of the load areas and assumes this capacity can be fully realised. This is also the case for determining the feasibility of demand management solutions as outlined in section 4.3 below.

4.3 Options considered

Ausgrid has considered Stand Alone Power Systems (SAPS) and other demand management solutions to determine their commercial and technical feasibility to assist with the identified need for Tarro ZS. Each of the solutions considered is summarised below using the following approach:

- SAPS are considered separately since they have the technical potential to provide a complete solution, subject to financial constraints,
- If SAPS are not viable, a build-up approach is used to assess the feasibility of stacking other solutions together such as power factor correction, demand response, customer solar power systems, customer energy efficiency, battery storage and dispatchable generators to form a complete demand management solution.

4.3.1 Stand Alone Power Systems (SAPS)

SAPS self-generate, store and supply electricity to connected customers that are physically disconnected to the wider electricity grid. Typical SAPS are made up of solar panels, a battery storage system and a back-up diesel generator.

Ausgrid is currently trialling SAPS with selected customers living in fringe-of-grid areas of Ausgrid's network[1]. The program aims to explore how SAPS can provide an alternative electricity supply solution that improves reliability and safety of our service to remote and rural customers, as well as being sustainable and cost-effective.

Ausgrid's experience with proposals from SAPS providers during the trial has provided insights on the cost of SAPS. On average it would cost $50k-100k or more to supply a typical residential customer (based on their annual energy usage) using a SAPS. Assuming a mid-point SAPS cost of $75k each, the number of customers that Ausgrid would be able to supply via SAPS using all the available funds would only be around 5 to 14 customers. This is not sufficient to reduce, defer or postpone the proposed preferred network solution.

Since SAPS are not viable, the following sections describe a build-up approach to assess the feasibility of building a complete demand management solution using other means of reducing demand.

4.3.2 Demand response

Demand response is a common demand management option and offers a relatively mature solution for standard network overload needs. Demand response can involve a mix of a temporary reduction in customer load and/or the use of embedded generation to either replace grid supplied electricity to the customer or export to the local grid.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical demand response program that reduced peak demand for the top 200 hours. The demand response required for the top 200 hours of demand is 2MVA. Past practice shows that costs for traditional demand response from commercial and industrial (C&I) customers is in the range of $50-150 per kW for 40-100 hours of dispatch and 3-5 months availability.

Assuming that 1MW in demand response was available in the area and could be acquired for an estimated $75-125 per kVA per year for 12 months availability, approximately $75-125k would be required each year. The cost of this solution represents:

- $75-125k (19% to 32%) of the available funds in the 1-year deferral case ($0.39m available funds),
- $150-250k (20% to 34%) of the available funds in the 2-year deferral case ($0.74m available funds), and
- $225-375k (22% to 36%) of the available funds in the 3-year deferral case ($1.04m available funds).

Additional solutions are needed to address the energy requirement outside of peak demand periods. Further details of other demand management solutions and and assessment of their viability is provided below.

4.3.3 Customer power factor correction

As a mature and proven demand management solution, customer power factor correction is both technically feasible and offers reliable permanent reductions at a low cost. Analysis of customer interval data indicates a commercial peak demand reduction potential of less than 70kVA at Tarro ZS. At a projected demand management cost of about $25-50 per kVA, or a total cost of around $2-4k, the solutions appear cost effective. However, this solution would contribute only 1.4% of the required 5MVA demand reduction.

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[1] https://www.ausgrid.com.au/In-your-community/Stand-Alone-Power-Systems

Other DM solutions would need to be considered cost-effective to enable customer power factor correction to form part of a DM solutions mix. Further details of other demand management solutions and and assessment of their viability is provided below.

4.3.4 Customer solar power systems

A possible demand management solution might be to provide a financial incentive to customers to invest in new solar power systems such that an accelerated take-up of solar reduces the forecast demand and energy, which can alleviate the impact of overload conditions. Analysis of interval data for Tarro ZS shows that while solar generation is partially coincident with the energy shortfall, it offers no reduction in load during non-solar hours.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical incentive program to encourage customer investment in solar power. If we assumed that incentives of about 25% of customer investment might encourage additional customer take-up of solar that would otherwise not occur, an incentive of about $250 per kVA would, for example, incentivise an additional 1 MW of customer solar power systems requiring a total customer incentive payment of about $250k. As solar power system generation is subject to hourly, seasonal and cloud cover variation (ie the solar "bell curve"), an example of 1 MW solar array is estimated to generate up to 1.4GWh annually, which translates into roughly 33% of the annual energy compared to a load reduction of 1 MW at peak and proportional reductions at other times of the year.

While customer solar power systems would address a material amount of the energy reduction requirement compared to power factor correction or demand response, the funding constraints and fixed times when solar is able to reduce demand mean that only a limited quantity of solar could be afforded and that all remaining funds should not be entirely spent on solar. Assuming that 5 MW of additional solar could be procured for around $1.25m, the running total cost of demand management solutions from demand response, power factor correction and customer solar power systems would be as follows:

- 1-year deferral: Total cost $1.2-1.5m comprising 1MW of demand response $75-125k for 1 year, 70 kVA of power factor correction: $2-4k and 5MW of customer solar systems: $1.25m which well exceeds the available funds under this scenario of $0.39m.
- 2-year deferral: Total cost $1.3-1.6m comprising 1MW of demand response $150-250k for 2 years, 70 kVA of power factor correction: $2-4k and 5MW of customer solar systems: $1.25m which well exceeds the available funds under this scenario of $0.74m.
- 3-year deferral: Total cost $1.4-1.8m comprising 1MW of demand response $225-375k for 3 years, 70 kVA of power factor correction: $2-4k and 5MW of customer solar systems: $1.25m which well exceeds the available funds under this scenario of $1.04m.

From the above analysis, there are insufficient demand management funds available to develop a solution that can adequately reduce peak demand and energy to a level that can enable the proposed network solution to be reduced, deferred or postponed.

4.3.5 Customer energy efficiency

Customer energy efficiency improvements as a demand management solution provides a financial incentive to customers to accelerate take-up of energy efficiency improvements with the aim of reducing their forecast energy consumption and the impact of overload conditions.

Following the build-up approach up to Section 4.3.4 above, there are no funds available for this solution to be considered part of a cost-effective alternative.

4.3.6 Large customer energy storage

While this option is technically feasible and offers a viable form of demand response, current and near-term pricing indicates that the solution would not be economic in comparison with demand response. At an estimated cost of over $1M per MWh, a peak lopping storage solution to address the top 100-200 hours would need to leverage significant other market benefits to be viable and yet would only address a small component of the energy shortfall.

There are insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.7 Standby generation

Standby generation, such as diesel generators, are a flexible form of network support which are leased and connected to the relevant part of the network experiencing a constraint. Typical cost structures for leasing standby generators comprise of weekly hire costs, usage costs (charged per hour when the generator is running) and fuel costs. Due to the nature of a major equipment outage that may be experienced at Tarro ZS and how a wide area may be impacted, it is likely that a standby generator would need to be connected at 11kV, requiring the leasing of a step-up transformer in addition to the generator.

Since a major equipment outage could occur at any time, a standby generator utilised as part of a demand management solution would need to be available and therefore leased for 52 weeks each year. Typical leasing costs might be upwards of $300k per year (or at least $900k for 3 years) per 1 MVA of standby generation capacity which does not account for other costs necessary to establish a standby generator such as usage, fuel and a step-up transformer.

There are insufficient funds available for standby generation given the entire available demand management funds of $0.39-1.04m. Standby generators are not considered cost-effective in this instance.

5 Conclusion

Based on the demand management options considered in Section 4, it is not considered possible that sufficient demand management measures could be feasibly implemented to achieve the required demand reduction to make project deferral technically and economically viable. Consequently, a Options Screening Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.