Addressing increased customer demand in the Circular Quay load area

NOTICE ON SCREENING FOR SAPS AND NON-NETWORK OPTIONS

02 June 2023

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Addressing increased customer demand in the Circular Quay load area

Notice on screening for SAPS and non-network options – June 2023

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1 Introduction

Forecast electricity demand in the Circular Quay load area has increased significantly in recent years as the Sydney CBD goes through a period of substantial change and regeneration and planning changes have resulted in an increase in the height of developments permitted. The City of Sydney's Central Sydney Planning Strategy recognises the CBD's role in the continued growth and economic success of wider Sydney and includes changes to:[1]

- Introduce a new planning pathway for building heights and densities above established maximum limits; and
- Increase building height limits from 80 to 110 metres along the western edge of the CBD.

Both of these changes in the planning arrangements have resulted in greater expected electricity demand in the Circular Quay load area.

In addition, the development of the Sydney Metro (with CBD services scheduled for 2024) and its stations have resulted in several 'over station' developments that include large commercial precincts and residential premises.[2] These developments have started to add significant electricity demand in the Circular Quay load area, which is expected to continue in the near future.

In tandem with this changing demand, the Dalley St Zone Substation (ZS), which is currently one of the six ZS supplying the Circular Quay load area, is due to be decommissioned in December 2024 due to its age and deteriorating condition. Specifically, a RIT-D undertaken by Ausgrid in 2018 to address condition issues at the Dalley St ZS and City East ZS (which were commissioned in 1969 and 1964, respectively) concluded that the preferred option was to decommission all equipment, and transfer load to the nearby Belmore Park and City North ZS, given the significant additional cost of alternate options (e.g., building a new ZS, or like-for-like refurbishment and replacement of the existing ZS).

Given the increased electricity demand in the Circular Quay load area, both current and forecast, Ausgrid considers that if action is not taken, there will be significant load that cannot be supplied following the decommissioning of Dalley St ZS.

Ausgrid has therefore commenced this RIT-D to assess options for meeting the changing customer requirements in the Circular Quay load area going forward.

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 the identified need can be found in the Draft Project Assessment Report (DPAR) for addressing increased customer demand in the Circular Quay load area.

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[1] City of Sydney, *Central Sydney Planning Strategy: 2016 to 2035*, Updated 15 March 2022, pages 13 and 19 (see: https://www.cityofsydney.nsw.gov.au/strategic-land-use-plans/central-sydney-planning-strategy).

[2] For example, see: https://www.planning.nsw.gov.au/assess-and-regulate/state-significant-projects/sydney-metro/pitt-street-over-station-developments/pitt-street-north-over-station-development, accessed 15 May 2023.

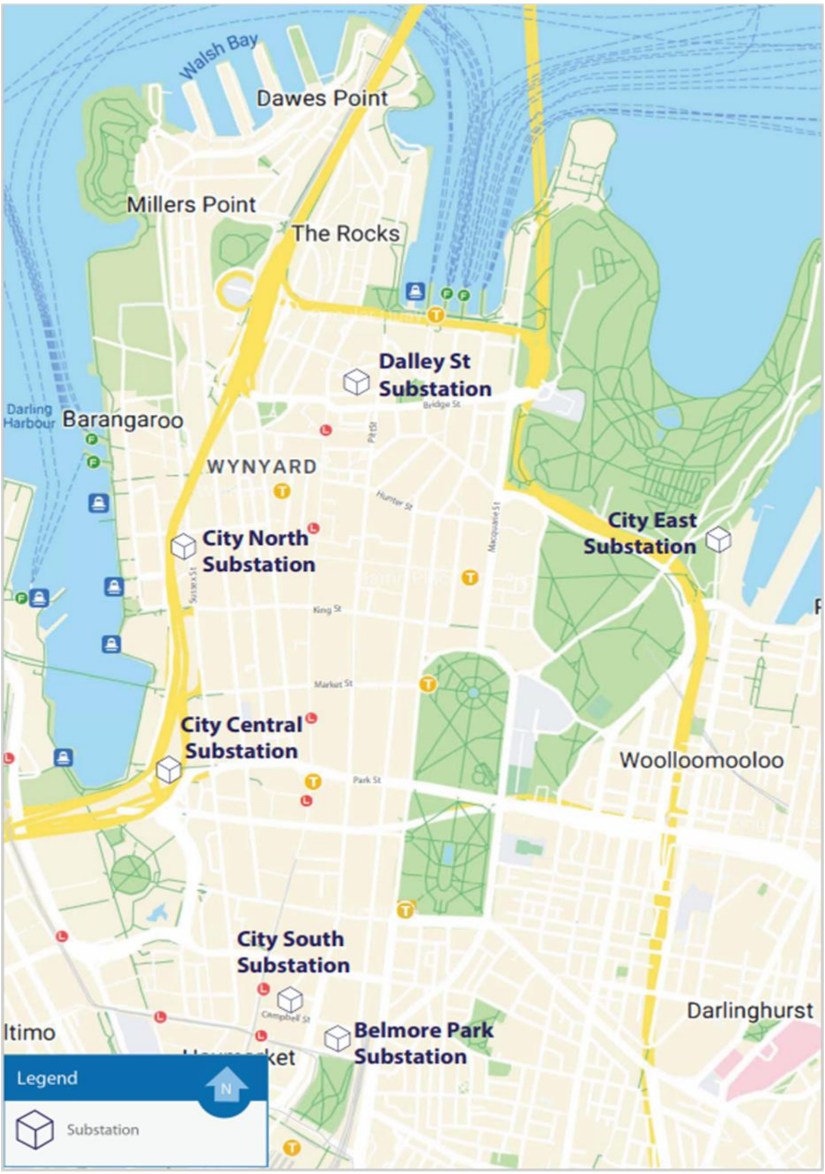
2 Forecast load and capacity

2.1 Demand Forecast

2.1.1 Overview of the Circular Quay load area

The Circular Quay network area is part of Ausgrid's 11 kV Sydney CBD network that serves customers in the area bounded between Barangaroo, Sydney Harbour, Darling Harbour, Central Railway Station and the Domain. The Sydney CBD is the commercial heart of Sydney and contains a significant concentration of office buildings, commercial businesses and apartments that all use substantial amounts of electricity. The peak demand for the Sydney CBD area is currently approximately 350 MVA in the summer, driven predominantly by summer air-conditioning. An overview of the current Sydney CBD network area is presented in Figure 1 below.

Figure 1: Overiw of the current Sydney CBD network area



The Circular Quay load area is currently served by six zone substations (ZS), the oldest two of which (Dalley St ZS and City East ZS) are in the process of being decommissioned due to deteriorating condition issues associated with assets reaching the end of their serviceable lives. Their decommissionings are expected to be completed by March 2024 and December 2024, respectively.

In recent years, there has been extensive redevelopment in the Circular Quay load area and a resulting increase in customer loads on feeders currently supplied from the Dalley St ZS.

Ausgrid has observed an increase in the number and scale of large customer load connection applications. This trend can generally be attributed to the redevelopment of buildings that surpass the height of their predecessors. These changes in the planning arrangement have resulted in greater expected electricity demand in the Circular Quay load area. In addition, the development of the Sydney Metro (with CBD services scheduled for 2024) and its stations have resulted in several 'over station' developments that include large commercial precincts and residential premises.[3] These developments have started to add significant electricity demand in the Circular Quay load area, which is expected to continue in the near future.

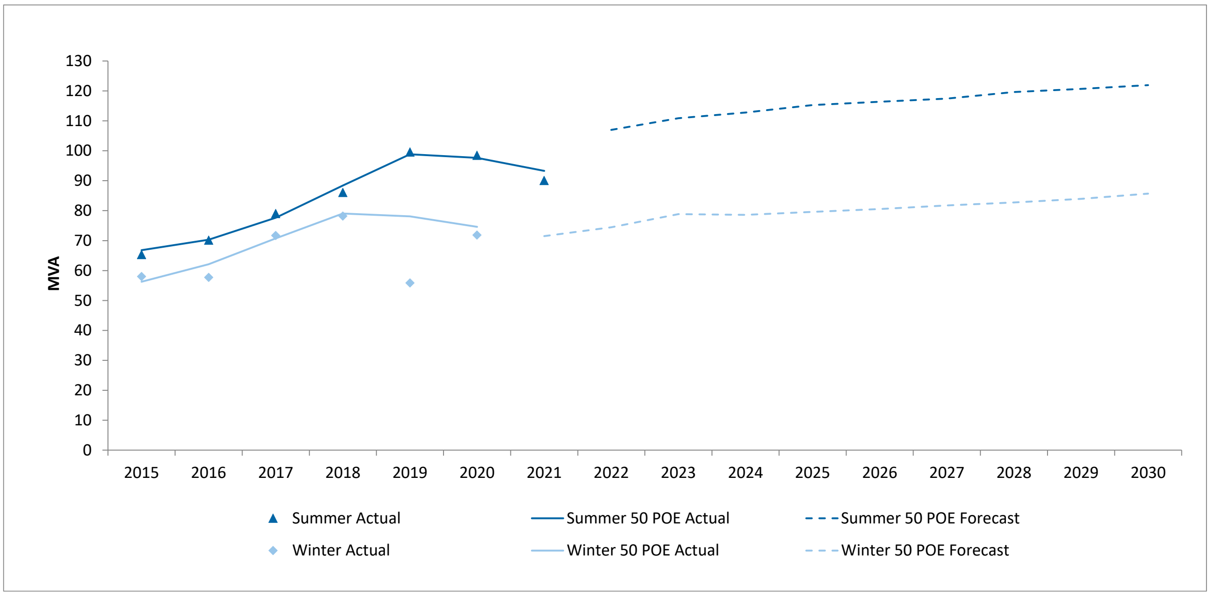
Refer to the Draft Project Assessent Report for further details around the identified need and consultation on how to most efficienctly provide supply to the Circular Quay network area considering forecast demand and the retirement of Dalley St ZS.

2.1.2 City North zone substation demand forecast

Figure 1 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 City North zone substation (ZS).

The City North (ZS) has a total capacity of 330.4 MVA and a firm capacity of 167.9 MVA. In 2020/21, the maximum demand on zone substation was 90.1 MVA at 12:45pm AEDT on 22 Feburary 2021. The weather corrected demand at the 50 POE level was 93.3 MVA. The power factor at the time of summer maximum demand was 0.951.

Figure 2: Demand forecast combined City North zone substation



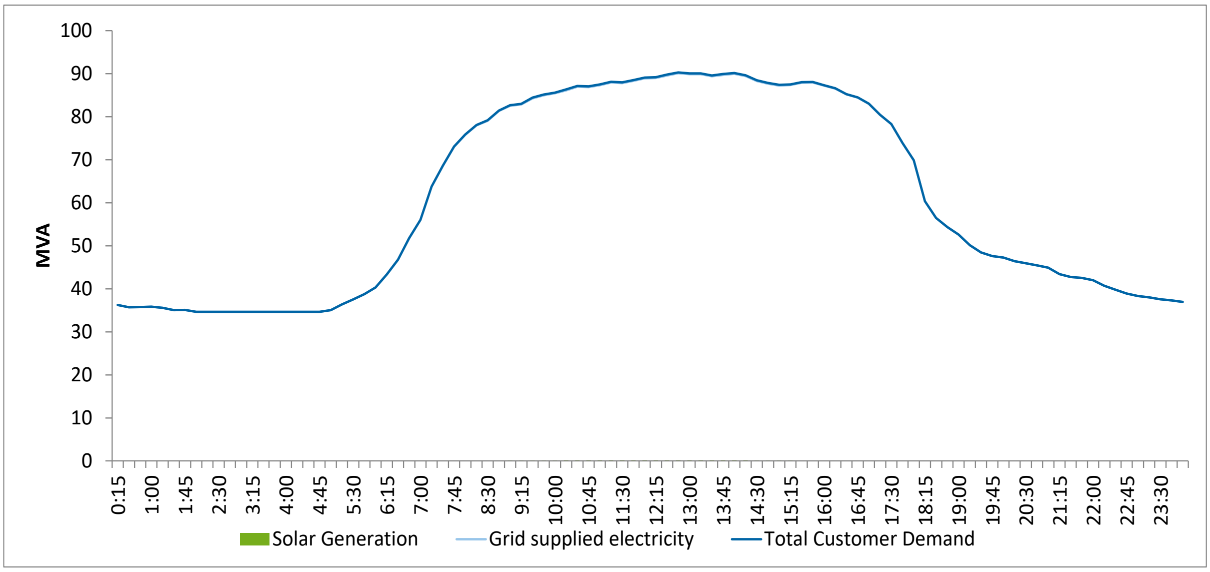
[3] For example, see: https://www.planning.nsw.gov.au/assess-and-regulate/state-significant-projects/sydney-metro/pitt-street-over-station-developments/pitt-street-north-over-station-development, accessed 15 May 2023.

2.2 Pattern of use

Over the past 7 years, annual maximum demand at City North ZS has typically occurred in summer between 12:30pm and 2:00pm AEDT.

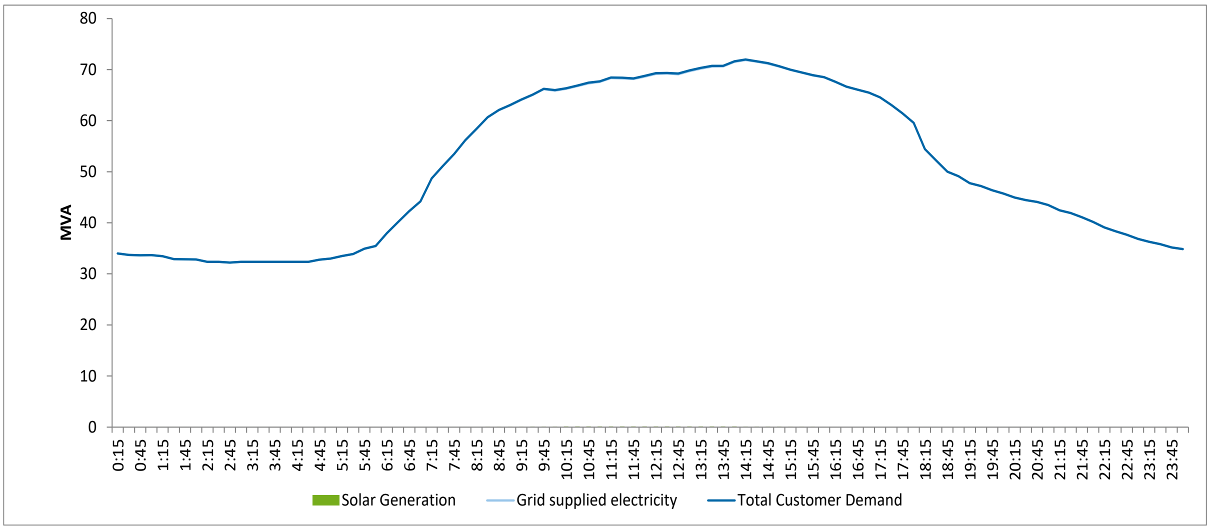
There is a total Solar PV capacity of approximately 300 kW connected to City North ZS. At the peak time of 12:45pm AEDT on 22 February 2021, these PV systems are estimated to have been generating 200 kW. Figure 3 shows the load trace on this day including the contribution from customer solar power systems.

Figure 3: Summer peak day demand profile and PV contribution at City North ZS on 22 Feburary 2021



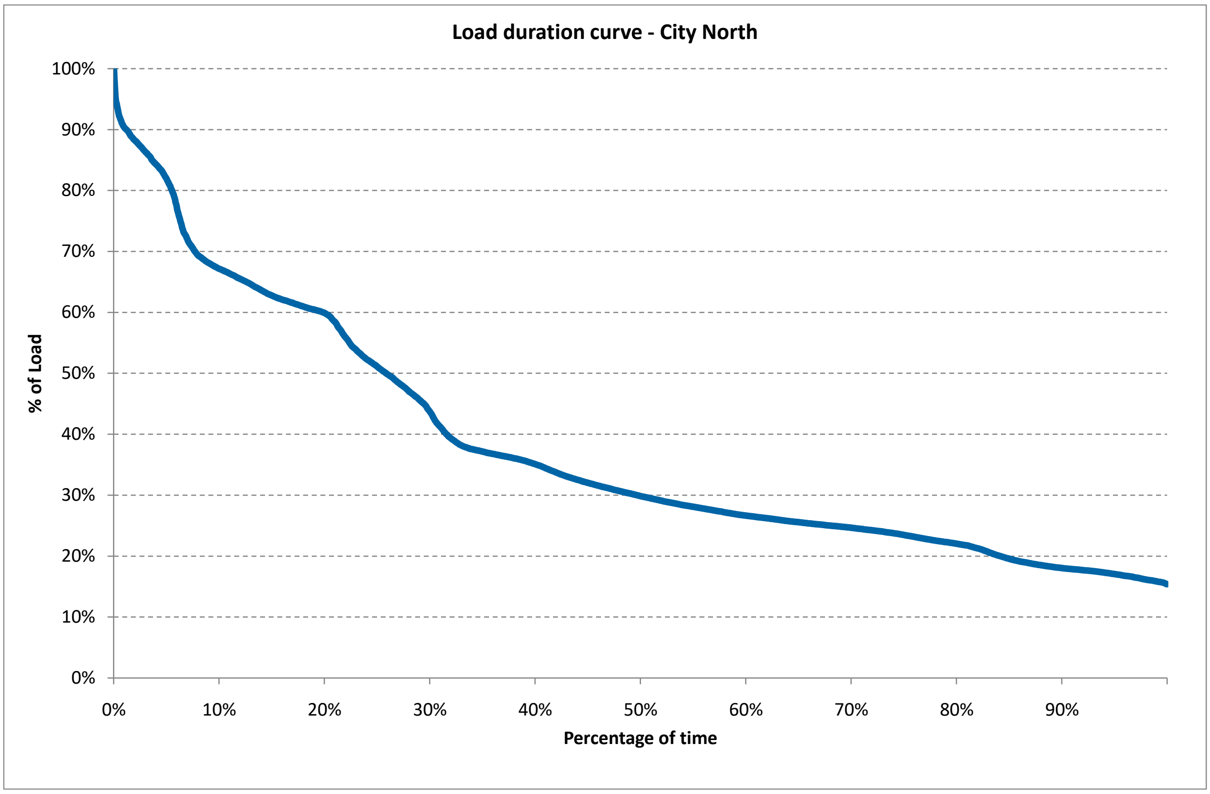
Over the past 7 years, the time of winter peak has typically occurred between 10:15 am and 2:45pm AEST. At the peak time of 2:15pm AEST on 12 May 2021, the estimated generation from PV systems is 140 kW. Figure below shows the load profile for the peak demand day 12 May 2021 including the contribution from customer installed solar power systems.

Figure 4: Winter peak day demand profile and PV contribution at City North ZS on 12 May 2021



The load duration curve used in the analysis is presented in the Figure 5 below. It is assumed that the load types supplied will not change substantially into the future and therefore the load duration curve will maintain its characteristic shape.

Figure 5: City North area load duration curve



In the event of a network outage on the summer maximum demand day, there is a maximum shortfall of around 90.1 MVA when compared to the actual peak (non-weather corrected). The shortfall would occur for most of the day as seen in 3 above.

Similarly, for the winter peak demand day, the shortfall would also be for most of the day as seen in Figure 4. The maximum shortfall would be around 71.9 MVA when compared to actual peak (non-weather corrected).

2.3 Customer characteristics

The customers supplied from City North ZS has a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2021/22 period are as follows:

Table 1: City North zone substation load area customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	3,526	4,988	404	8,918
% of Customers	39.5%	55.9%	4.5%	
Annual Consumption (MWh)	14,749	94,874	264,280	373,903
% of Annual Consumption	3.9%	25.4%	70.7%	
Number of Solar Customers	17	29	29	75
% of Customers with Solar	0.5%	0.6%	7.2%	
Average Annual Consumption (MWh)	4	19	654	42

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 $2022/23, unless otherwise stated.

Table 2: Summary of the credible options assessed

Option	Key components	Estimated capital cost (including decommissioning costs)
Option 1 – Install three new circuits connected at the City North ZS. This option includes installing three circuits simultaneously to meet future forecasts of customer load and minimises the disruption to residents and businesses in the CBD.	• Install a 16-way ductline from City North ZS to High Voltage (HV) Pit.50268 in Hickson Road; • Install a 16-way ductline from HV Pit.27979 in Hickson Road to the vicinity of Substation 6062 Barangaroo Point, and from HV Pit.50014 in Hickson Road to the vicinity of Substation 4793 Hickson Road/Windmill Street; • Install an 8-way ductline from HV Pit.50015 in Hickson Road to HV Pit.50003 at the base of Windmill Steps; and • Install an 8-way ductline from HV Pit.50004 at the top of the Windmill Steps to HV Pit.50125 in Argyle Street near Substation 6869 Cumberland Street/Argyle Street.	The estimated capital cost of this option is $15.0 million, commissioning in 2024/25. Planned maintenance is expected to be around $10,000 per year to cover switching operations. This option takes advantage of Barangaroo Central and the Sydney Metro developments being under construction so that this area will have less traffic (road and pedestrian), and reduced reinstatement and traffic control costs.
Option 2 - Install two new circuits at the City North ZS. Third circuit is deferred until required. The scope of this option is similar to Option 1 except the third new circuit is deferred to a later date.	The trigger for the third feeder is the connection of forecast load, which depends on the demand scenario considered: • Under the low demand scenario, a third feeder is never required since all commissioned and committed loads can be accommodated by two circuits; • Under the central and high demand scenarios, a third feeder is required by 2027/28.	The estimated capital cost of this option is $13.1 million for the first two feeders, commissioning by 2024/25. The third feeder is estimated to cost approximately $3.2 million with timing dependent upon the scenario. Planned maintenance costs are estimated at $15,000 per year, due to switching operations being more complex. Once the third feeder is installed, planned maintenance costs reduce to $10,000 per year.

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	Description	Reason why option was not progressed
Maintain a ZS at Dalley Street to accommodate new connected loads	Refurbish the existing ZS, or build a new ZS, at Dalley Street to avoid having to transfer load	Costs are substantially higher than the credible option with no corresponding increase in benefits. Ausgrid considers that the refurbishment of Dalley St would incur costs similar to that for the build of a new substation (the 2018 RIT-D estimated that a new substation was expected to cost in the order of $155 million). The options for maintaining the Dalley St ZS also require a longer timeframe due to the need to refurbish the existing ZS, or construct a new ZS on a suitable site. This option is therefore not considered to be economically or technically feasible.
Install new feeders from adjacent substation	Transfer load to adjacent zone substations, in particular Belmore Park ZS	Costs are substantially higher than the credible option with no corresponding increase in benefits (preliminary costing show an approximate capital cost of $50 million for this option). This option is therefore not considered to be economically feasible.

Table 4: Summary of the three scenarios investigated

Variable	Scenario 1 – central demand scenario	Scenario 2 – low demand scenario	Scenario 3 – high demand scenario
Demand	Central demand forecast (as outlined in the Draft Project Assessment Report)	Low demand forecast (as outlined in the Draft Project Assessment Report)	High demand forecast (as outlined in the Draft Project Assessment Report)
VCR	$68.40/kWh across all scenarios		
Discount Rate	3.44% across all scenarios		

Ausgrid has weighted each of the demand scenarios consistent with its confidence in the forecast loads in each scenario proceeding, based on experience with past developments and information available to date.

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

3.1 Preferred option at this stage

Ausgrid considers that Option 1 is the preferred option that satisfies the RIT-D at this stage of the process. It involves installing three new circuits at the City North ZS. Ausgrid is the proponent for Option 1.

The estimated capital cost of Option 1 is $15.0 million, and commissioning is assumed in 2024/25. Additional planned maintenance costs are expected to be minimal (approximately $10,000 per year) since the circuits are located underground.

Refer to the Draft 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

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 5 below shows the available funds for a deferral of the network investment for 1, 2 and 3 years. The required peak demand reduction is very large due to the expected decommissioning of the Dalley St ZS and the proposed connections affecting the Circular Quary load area.

Table 5: Required demand reduction and available funds at Circular Quay load area

Deferral year	Required peak demand reduction per year	Available demand management funds	
1 year	9MVA*	$1.0m	$109/kVA/year
2 years	9MVA*	$1.9m	$105/kVA/year
3 years	9MVA*	$2.7m	$101/kVA/year

*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 9MVA of demand reduction is required in 2024/25 with total available demand management funds of $1.0 million, which is equivalent to $109/kVA/year,
- For 2-year deferral, 9MVA of demand reduction in 2024/25 and 2025/26 with total available demand management funds of $1.9 million, which is equivalent to $105/kVA/year, and
- For 3-year deferral, 9MVA of demand reduction in 2024/25, 2025/26 and 2026/27 with total available demand management funds of $2.7 million, equivalent to $101/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 Circular Quay load area. 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[4]. 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 13 to 36 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 100-200 hours. 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 9 MVA 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, the cost of this solution represents:

- $0.7 - $1.1m (69% to 115%) of the available funds in the 1-year deferral case ($1.0m available funds),
- $1.4 - 2.3m (71% to 119%) of the available funds in the 2-year deferral case ($1.9m available funds), and
- $2.0 - 3.4m (74% to 124%) of the available funds in the 3-year deferral case ($2.7m available funds).

Additional solutions beyond Demand Response are needed to address the requirement of demand reductions 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 798kVA at City North ZS. At a projected demand management cost of about $25-50 per kVA, or a total cost of around $5-10k, the solutions appear cost effective. However, this solution would contribute only 8.9% of the required 9MVA demand reduction.

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

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 City North 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 (i.e., the solar "bell curve"), the 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.

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 kW would, for example, incentivise an additional 1 MW of customer solar power systems requiring a total customer incentive payment of about $250k. Approximately $2.3m would be required in order to achieve the required demand reduction of 9MW, that would address 33% of the annual energy reduction requirement equivalent to a 9MW peak. This is in line with the available funds under the 3-year deferral scenario and other solutions would be needed to achieve the required demand and energy reductions.

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. Customer energy efficiency improvements as a demand management solution may help to alleviate energy shortfalls that occur for a substantial number of hours of the year, as shown in section 2.2.

To assess the viability of this solution, we estimated the potential cost and impact from a hypothetical incentive program to encourage customer investment in energy efficiency improvements. If we assumed a typical commercial premises that operates around 2000hrs per year (8am-5pm Mon-Fri) and that incentives of about 20-40% of customer investment might encourage additional customer take-up of energy efficiency improvements than would otherwise occur, an incentive of about $200-500 per kVA might achieve up to 9MVA of reduction at an approximate cost between $1.8m-$4.5m, which far exceeds the available funds. Consequently, we consider there is insufficient 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 City North 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.

When considering using the entire available demand management funds for standby generation only, acquiring 9MVA of standby generation capacity would cost $2.7m per year for 9MVA excluding usage, fuel and step-up transformer costs. There are insufficient funds available for this solution to be considered part of a cost-effective demand management solution.

4.3.8 Combining demand management solutions

There is no demand management solution mix that could meet the required demand reductions with the funds that are available. Apart from power factor correction, the costs of all demand management solutions considered either use up all or nearly all available funds and deliver only a partial solution, such as customer behavioural demand response and customer solar power systems, or that the available funds are insufficient to fund a sufficient quantum of demand reductions, such as customer energy efficiency, large customer energy storage and standby generation. Power factor solution alone is insufficient to adderess the required demand reduction.

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, an Options Screening Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.