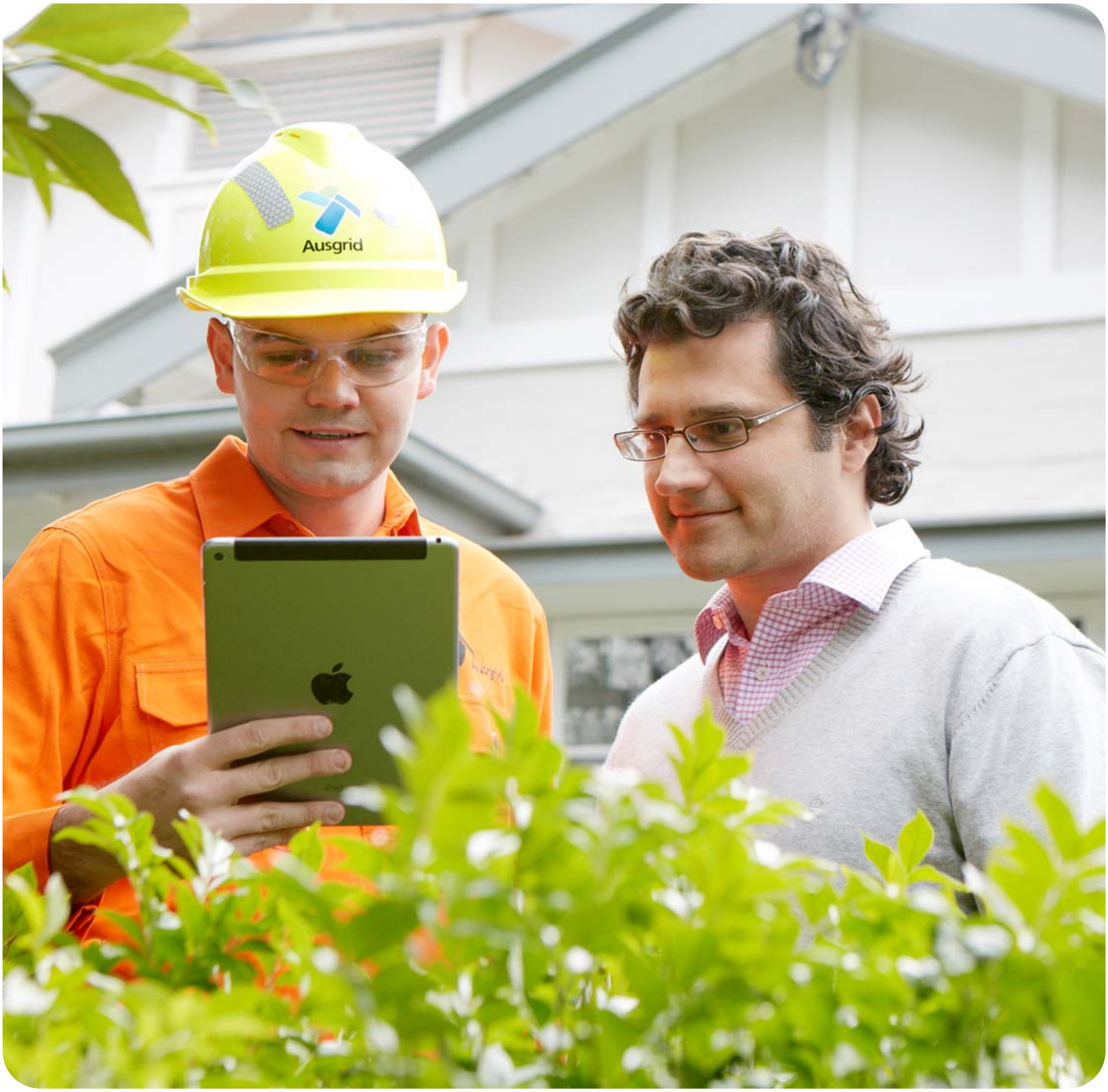
Addressing reliability requirements in the Enfield network area

Notice on screening for non-network options

December 2017



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1 Aging network assets at Enfield zone substation require replacing

The Enfield zone substation was installed in the 1960s by an Ausgrid predecessor, the, then, Sydney County Council, and its assets are now reaching the end of their service lives and are in poor condition. These assets have already led to network asset failures and involuntary load shedding in the area and are forecast to continue to do so, with increasing frequency and magnitude, going forward. This exposes Ausgrid’s customers in the Enfield area to a level of involuntary load shedding that exceed allowable levels under reliability standards applicable to Ausgrid.

Many assets installed around this period in time that help supply the wider Canterbury-Bankstown area have, in recent years, reached, or exceeded, the end of their expected service lives. Planning for a solution to address deteriorating and aging assets in this region began in 2012, with an overall staged replacement plan being formulated for these assets. As part of this wider plan, Ausgrid has recently commenced construction of a new zone substation at Summer Hill, which was identified as the most efficient option for replacing ageing assets at the Dulwich Hill zone substation, which is also in the Canterbury-Bankstown area.

Changes to the National Electricity Rules (NER) in July 2017 have meant that later stages of the wider replacement plan for ageing assets in the Canterbury-Bankstown area are now subject to the Regulatory Investment Test for Distribution (RIT-D). These changes allowed businesses, like Ausgrid, a grace period to transition to this new requirement and exempts replacement projects that meets a defined set of criteria as committed to by 30 January 2018 from the RIT-D process.

Ausgrid’s planning for the ageing asset, and consequent reliability issues at the Enfield zone substation began in 2010 and, in 2015-16, it was determined that the most efficient solution was retiring the existing substation and replacing it with a new zone substation at Strathfield South. While Ausgrid is now well advanced in the planning, approvals and procurement processes for this new substation, it is not yet ‘committed’ (and is not expected to be by 30 January 2018).

Accordingly, Ausgrid has initiated this RIT-D for replacing ageing assets at the Enfield zone substation project in order to identify a preferred option that ensures Ausgrid is able to satisfy its reliability and performance standards.

A full discussion of asset conditions and the identified need can be found in the Draft Project Assessment Report (DPAR) for addressing reliability requirements in the Enfield network area.

This notice has been prepared under cl. 5.17.4(d) of the NER and summarises Ausgrid’s determination that no non-network option is, or forms a significant part of, any potential credible option for this RIT-D. In partciualr, it sets out the reasons for Ausgrid’s determination, including the methodologies and assumptions used.

2 Forecast load and capacity at Enfield zone substation

2.1 Load forecast

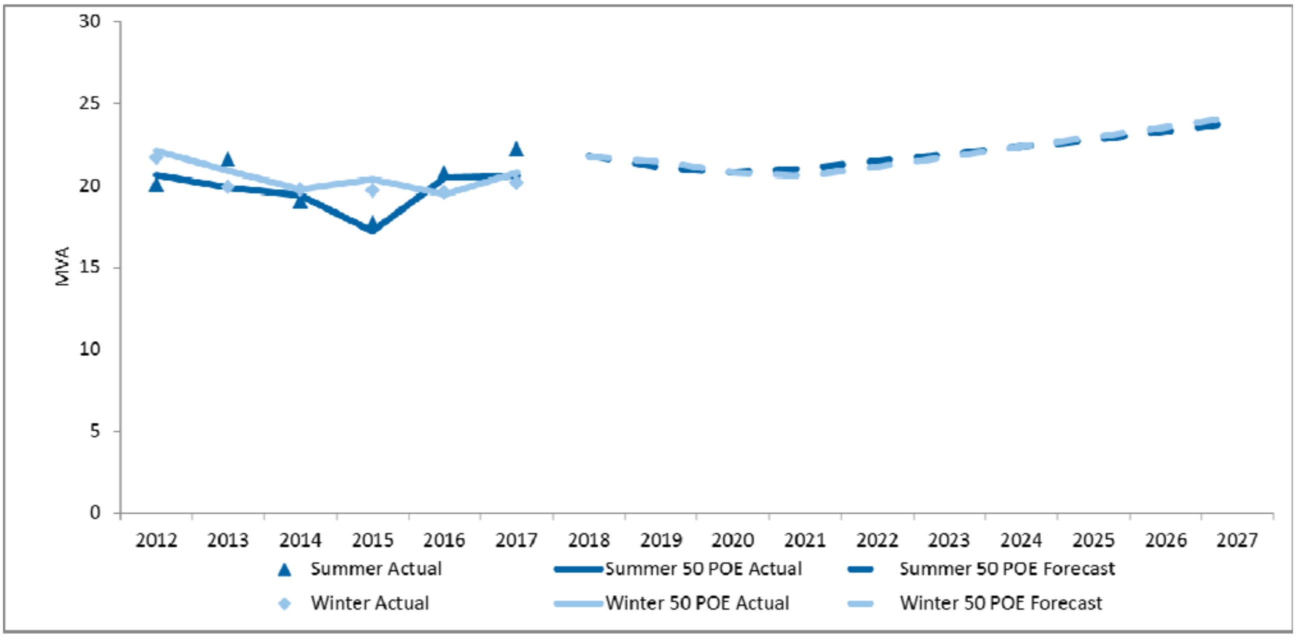
The Enfield zone substation has a total capacity of 70.5 MVA and a firm capacity of 44.8 MVA. In 2016/17, the maximum demand on the zone substation was 22.2 MVA at 6:15pm AEDT on 10 February 2017. The weather corrected demand at the 50% Probability of Exceedance level (50 POE) was 20.6 MVA. The power factor at the time of summer peak demand was 0.95.

Maximum demand has occurred in both summer and winter in past years with maximum demand typically occurring in winter during relatively mild summers. In the winter season, the peak demand typically occurs between 6:30pm and 7:30pm AEST. In the 2016 winter period, the maximum demand was 20.2 MVA at 7:30pm on 27 June 2016. The weather corrected demand at the 50% Probability of Exceedance level (50 POE) was 20.8 MVA. The power factor at the time of winter peak demand was 0.96.

Peak demand at the Enfield zone substation is forecast to grow at about 1.5 percent per year to 2027 for both summer and winter. This growth represents the 50% Probability of Exceedance level used for planning at Ausgrid.

Figure 1 below shows the historical actual demand, the 50 POE weather corrected historical actual demand and the 50 POE forecast demand for both winter and summer for Enfield zone substation.

Figure 1 – Demand forecast at Enfield zone substation

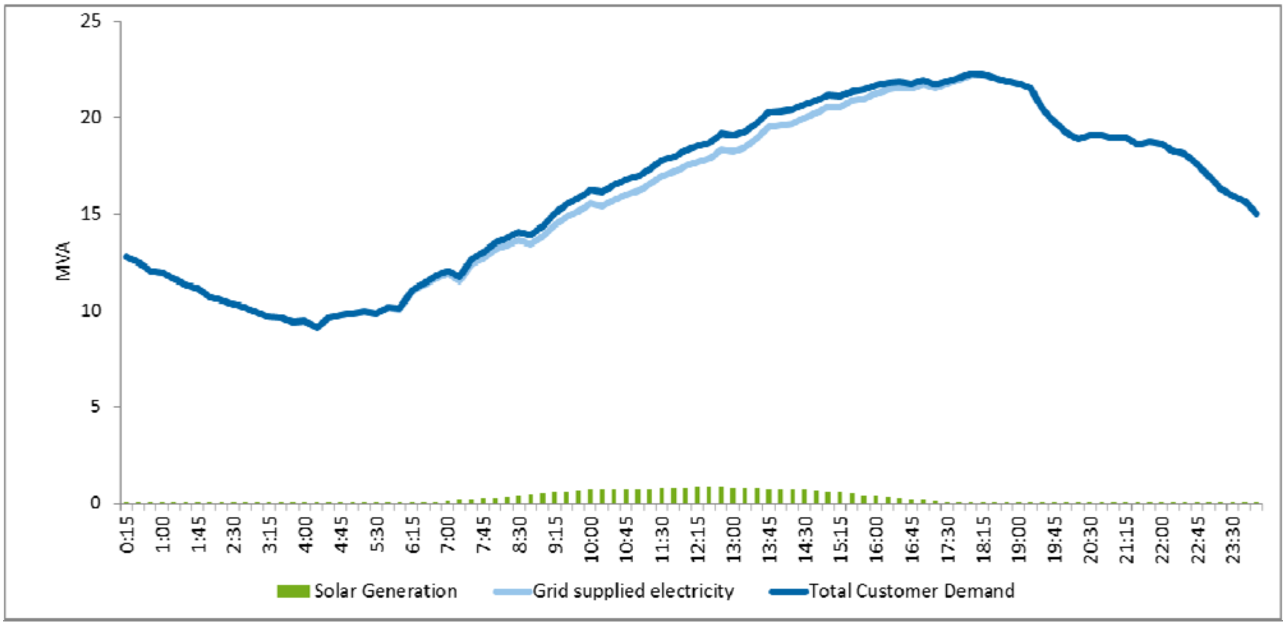


2.2 Pattern of use

Summer peak electricity demand at Enfield zone substation occurs on hotter days driven predominantly by air conditioning usage. Over the past 7 years, and where peak annual demand occurs in summer, the time of peak has occurred as early as 5pm and as late as 9pm AEDT. As noted above, the most recent summer maximum demand occurred at 6:15pm AEDT.

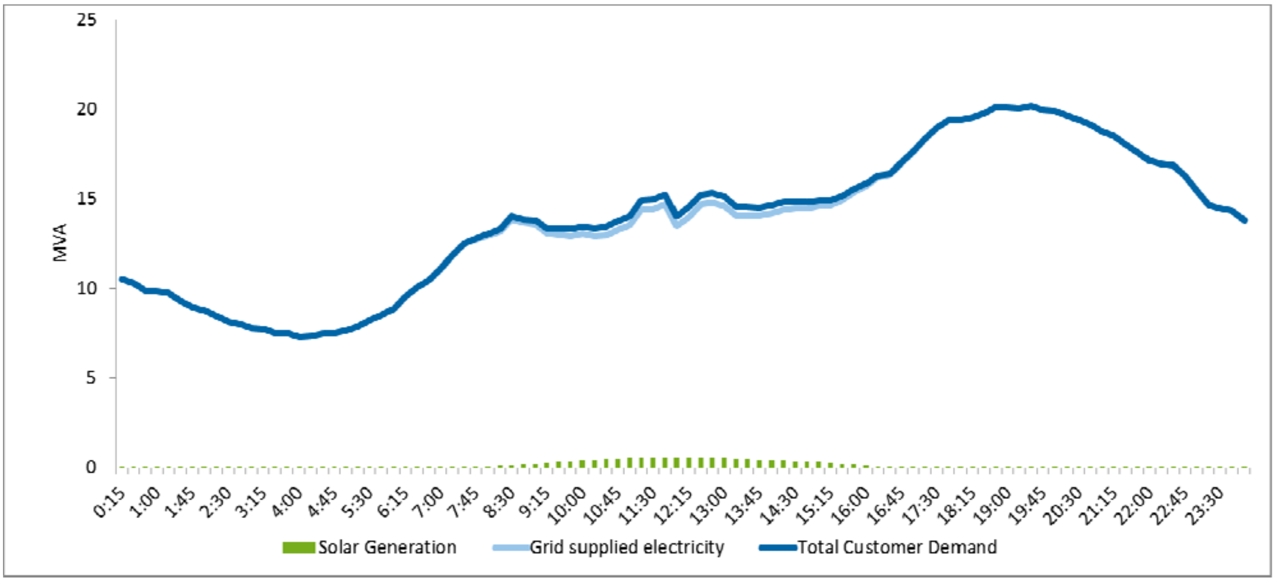
There is a total capacity of about 1.2 MW of solar PV connected to the zone substation, composed of about 1.0 MW of solar power on residential premises and 0.2 MW of solar on non-residential premises. At the peak time of 6:15pm on 10 February 2017, these PV systems supplied about 0.06 MW of the customer load. Figure 2 below shows the load trace for the 10 February 2017 peak demand day including the contribution from customer installed solar power systems.

Figure 2 – Summer maximum demand profile at Enfield zone substation (10 February 2017)



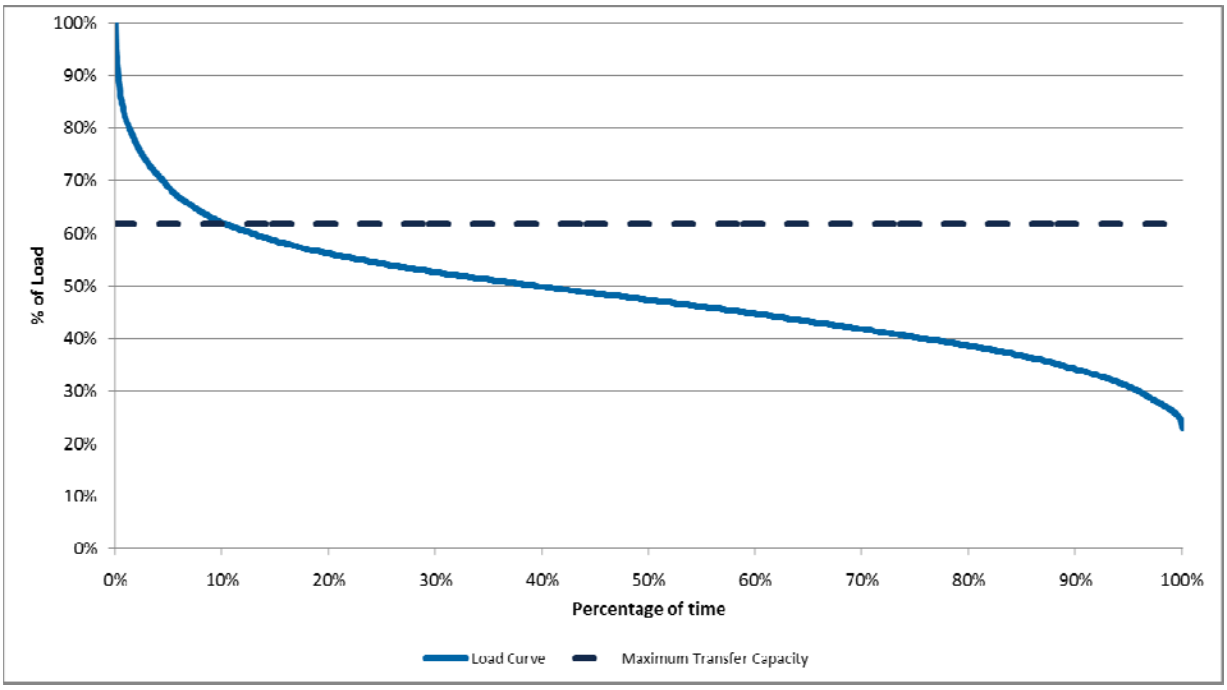
Winter peak electricity demand at Enfield zone substation occurs on colder evenings driven predominantly by heating applicances. Over the past 7 years, the time of winter peak has typically occurred between 6:30 pm and 7:30pm AEST. Figure 3 below shows the load trace for the 26 June 2016 peak demand day including the contribution from customer installed solar power systems.

Figure 3 – Winter maximum demand profile at Enfield zone substation (27 Jun 2016)



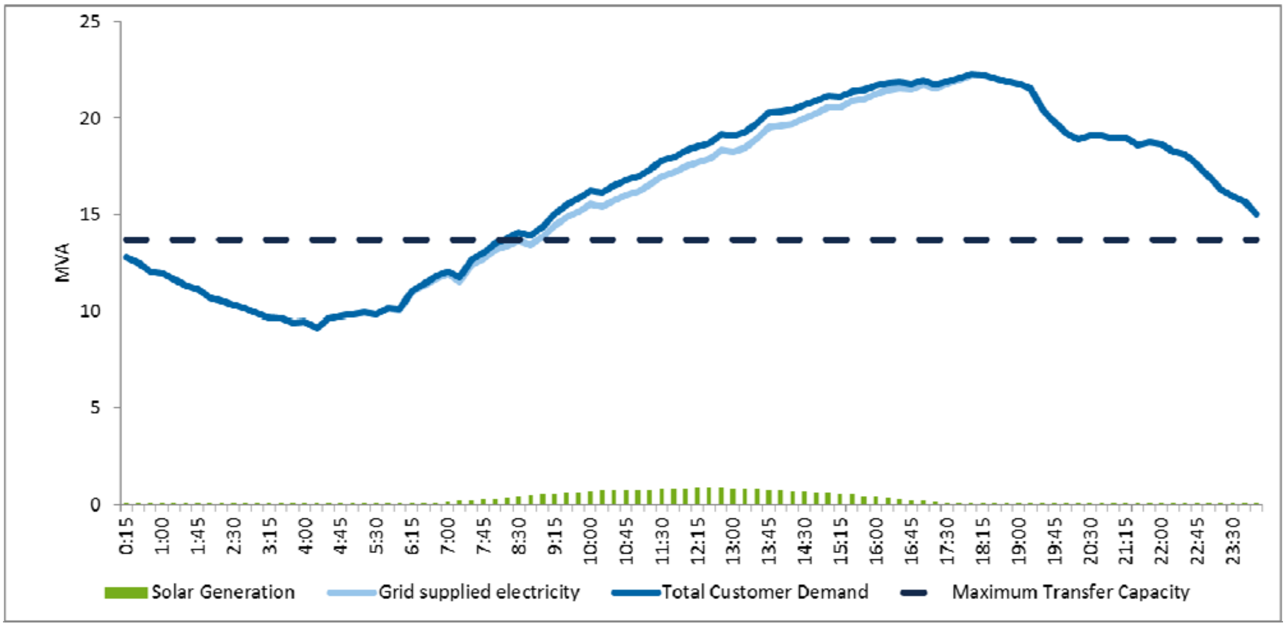
The Enfield zone substation has a current load transfer capacity of 13.7 MVA or about 62% of the most recent actual maximum summer demand and 68% of most recent maximum winter demand. Based upon the data period from May 2016 to April 2017, electricity demand for Enfield Zone Substation exceeds the transfer capacity for about 130 days and 850 hours per year (10% of total hours) with 350 hours in summer and 500 hours in winter. Over this period, there is a total of about 1,700 MWh of unmet load in the case of a loss of network supply from Enfield zone substation. The load duration curve for the period from May 2016 to April 2017, noting the transfer capacity, is shown below in Figure 4.

Figure 4 – Enfield Zone Substation Load Duration Curve (May 2016 to April 2017)



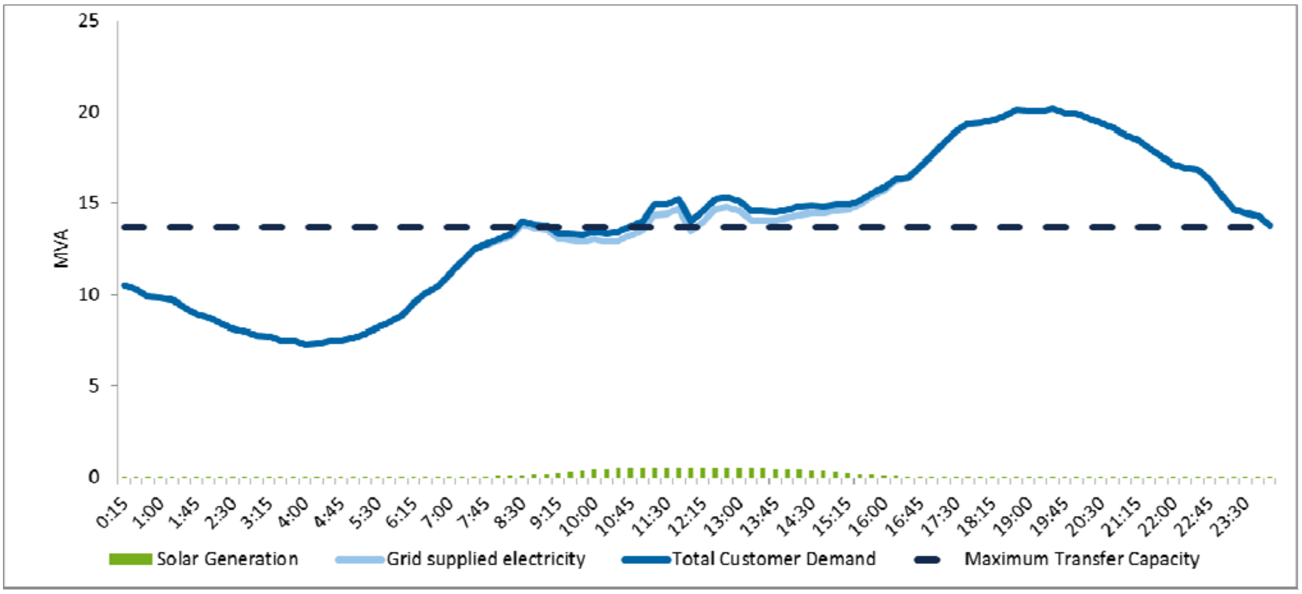
In the event of a network outage, and on a maximum summer peak demand day, after use of the maximum transfer capacity in an emergency switching of the network, there is a shortfall of network supply from 9:00 to Midnight or 15 hours. The maximum shortfall in network supply on 10 February 2017 would have been 8.5 MW at peak. See Figure 5 below.

Figure 5 – Summer maximum demand profile at Enfield zone substation with maximum load transfer



Similarly for a winter peak demand day, the shortfall in network supply would be for a total of 13 hours in the period from about 8:30am to Midnight. The maximum shortfall in network supply on 27 June 2016 would have been 6.5 MW at time of peak demand. See Figure 6 below.

Figure 6 – Winter maximum demand profile at Enfield zone substation with maximum load transfer



2.3 Customer characteristics

Enfield Zone Substation serves a mixture of residential and non-residential customers. A breakdown of the customer characteristics for the 2016/17 period is as follows:

Table 1 – Customer characteristics

Item	Residential	Small Non-Residential	Large Non-Residential	Total
Number of Customers	6,610	518	48	7,176
% of Customers	92%	7%	1%	
Number of Solar Customers	401	18		419
% of Solar Customers	96%	4%		
Annual Consumption (MWh)	33,741	11,627	34,032	79,400
% of Annual Consumption	42.5%	14.2%	43.3%	
Average Annual Consumption (MWh)	5.1	22	709	

About 60% of residential customers live in detached homes with an average usage of about 6.2 MWh per year. Households living in apartments, townhouses and flats have an average usage of about 3.5 MWh per year.

2.4 System limitations and restoration timeframes

Enfield zone substation is supplied by three 33 kV gas pressure cables (feeders 639, 640 and 641) that originate from Canterbury sub-transmission station. Among these feeders, feeder 640 has been identified as having the highest leakage rate and second worst availability of all gas pressured cables in Ausgrid's network, while feeder 641 has the tenth highest leakage rate in Ausgrid's network and the worst availability. Feeder 639 is also among the lower performing feeders in Ausgrid's network.

Consequently, concurrent feeder failures can lead to involuntary load sheeding. In February 2011 for example:

- feeder 640 failed while feeder 639 was out for service due to a gas leak;
- before feeder 639 could be returned to service, feeder 641 also failed; and
- the consequence of these coincident failures meant that a significant number of customers experienced involuntary load shedding over a period of four days, which peaked on 2 February when approximately 17,400 customers had their supply interrupted.

Ausgrid considers that the time required for restoration after a cable failure or switchboard of the type in the Enfield substation can vary between 10.5 and 24.5 days depending on the type of failure and the asset that failed. Detailed restoration assumptions are set out in Appendix D of the DPAR. Ausgrid notes that the February 2011 outage lasted for four days.

As part of restoring supply after an outage, the Enfield zone substation has load transfer capabilities that can mitigate the severity of involuntary load shedding. In particular, the Enfield zone substation has a 11 kV interconnection with Burwood, Campsie, Potts Hill, Greenacre Park, and Dulwich Hill.

In the event of a total loss of supply to Enfield zone substation, approximately 62 per cent of the load can be recovered within days via the 11 kV load transfer capacity of the existing network.

3 Proposed preferred option is to establish a new Strathfield South zone substation

Two credible options that have been assessed by Ausgrid in the DPAR to address future reliability concerns are summarised in the table below.[1]

Table 2 – Summary of the credible options considered

Network option description	Key components	Capacity	Estimated capital cost, $2017/18
Option 1 – Build a new Strathfield South substation to replace the existing Enfield substation	Enfield 132/11kV replaced with Strathfield South 132/11 kV	65 MVA	$28 million
Option 2 – Refurbish the existing Enfield substation	Switchgear and feeder replacement at the existing Enfield substation	50 MVA	$43 million

Option 1 is found to be the preferred option, which satisfies the RIT-D. It involves decommissioning the Enfield zone substation and replacing it with a new Strathfield South zone substation. Ausgrid is the proponent for Option 1.

In addition, Option 1 offers the following benefits:

- it has a significantly lower costs than Option 2 (eg, it involves $28 million of capital cost compared to $43 million);
- it provides greater network capacity than Option 2 (ie, 65 MVA compared to 50 MVA);
- it avoids upstream investment at the Canterbury sub-transmission substation, otherwise required; and
- it addresses condition issues at Enfield zone substation and also facilitates addressing future asset condition and capacity issues identified at Campsie zone substation.

The scope of Option 1 includes:

- construction of a 132/11kV zone substation on a greenfield site to accommodate two 50MVA power transformers, 132kV and 11kV switchgear and associated control and protection equipment;
- installation of 132kV connections to overhead 132kV feeder 911 that passes in close proximity to the new site;
- transfer of 11kV load from the existing Enfield zone substation to the new site; and
- decommissioning of the existing Enfield zone substation and associated 33kV gas pressure cables.

A new Strathfield South zone substation will be looped into the existing 132 kV overhead feeder 911, which runs near to the proposed site at Dunlop Street. Feeder 911 will be split at an appropriate location, and each end brought into the site via new underground cable sections. This will create one feeder between TransGrid's Sydney South Bulk Supply Point and Strathfield South, and one feeder between Strathfield South and Canterbury Sub-Transmission Substation.

It is anticipated that the sections connecting the two ends of the split feeder 911 with the zone substation will be underground, due to difficulties associated with an overhead connection in terms of complexities in the layout design, building setback changes, clearances and community issues.

[1] Ausgrid also considered decommissioning the existing Enfield zone substation entirely and transferring load to elsewhere in the network. However, the costs associated with this option are considered to be significantly greater than for the above options and this option is not expected to deliver commensurate additional market benefits. The option of decommissioning has therefore not been progressed.

The estimated capital cost of Option 1 is $28 million. Annual operating costs associated with this new capex are estimated to be around $140,000 per annum (assumed to be 0.5 per cent of the capital cost).

Ausgrid estimates that the environmental approval and construction timeline for Option 1 is 30 months, with assumed commissioning during 2020/21. The decommissioning of the existing Enfield zone substation and associated 33 kV feeders is expected to be completed by 2021/22. Ausgrid intends to commence work on delivering Option 1 in 2018 (in particular, we intend to award the design and construction contract in February 2018, have environmental approvals finalised in June 2018 and to commence construction in September 2018).

Overall, this finding confirms the earlier planning assessment exercises undertaken by Ausgrid in 2015 that concluded that a new Strathfield South substation is the most efficient option for replacing the assets at the Enfield zone substation.

4 Assessment of non-network solutions

4.1 Required demand management characteristics

A viable demand management solution must be capable of reducing the load on Enfield zone substation sufficient to retain supply to customers over the 10-24 days required for restoration. This reduction in supply can be permanent or temporary but must offer support in both summer and winter, align with the load profile post emergency load transfer and be cost effective in comparison with the preferred network alternative.

Due to the scale of the shortfall in electricity supply, we consider that a combination of permanent and temporary demand reductions offers the most plausible scenario for a cost effective non-network alternative. Refer to Section 2 for details on the load profile, demand forecast, emergency load transfer capacity and customer characteristics.

A detailed assessment of the load profile for Enfield zone substation over the May 2016 to April 2017 period shows that the shortfall in demand after emergency load transfers have been implemented is significant. Refer to Table 3 below for details on the network support requirements for the years from 2021/22 to 2023/24.

Table 3 – Customer supply shortfall

Year	MW	MWh	Days/year		Hours/year	
			Summer	Winter	Summer	Winter
2021/22	8.0	2,320	51	102	440	670
2022/23	8.5	2,720	60	105	500	750
2023/24	9.0	3,140	69	108	570	840

To be considered a feasible option, any demand management solution must be technically feasible, commercially feasible; and able to be implemented in sufficient time to satisfy the identified need in 2021/22.

4.2 Demand management value

The following table indicates the available funds that can be spent to achieve a 1, 2 or 3 year deferral of Option 1 expressed both as an overall cost and on a $/MWh basis. We have expressed the available funds on an energy basis as the demand management support is principally associated with a shortfall in energy capacity rather than a shortfall in peak demand capacity.

The stated benefits are in addition to an allowance of $75,000 per year to cover any Ausgrid administrative costs. Note that these figures are indicative only and that any credible demand management solution proposed will be evaluated against the preferred network solution in a full RIT-D evaluation.

Table 4 – Funds avaliable for demand management

Deferral benefits	Total avaliable benefit	Peak Load Reduction required (MW each year)	Load Reduction required (MWh each year)	Available $ per MWh
1 year deferral	$0.70m	8.0	2,320	$300
2 year deferral	$1.35m	8.5	2,720	$265
3 year deferal	$1.80m	9.0	3,140	$220

4.3 Demand management options considered

Ausgrid has considered a number of demand management technologies to determine their commercial and technical feasibility to assist with the identified need at the Enfield zone substation. Each of the demand management technologies considered is summarised below.

4.3.1 Customer power factor correction

While this option is technically feasible and offers permanent reductions sufficient to cover the large number of unmet load hours, there are few customers on a kVA demand tariff supplied from Enfield Zone Substation. Of the 7,176 customers connected to Enfield Zone Substation, only 48 are on a kVA demand tariff. Analysis of customer interval data indicates a technical potential of only about 0.8 MVA. Commercial potential is likely to range from 0.2 to 0.4 MVA. At a likely cost of about $25-50 per kVA, this solution is likely to be cost effective, but is estimated to contribute only about 3 to 4% of the requirement.

4.3.2 Customer solar power systems

While this option is technically feasible and offers permanent reductions, solar power systems are not estimated to offer a sufficiently cost efficient alternative, nor a material reduction in grid supplied demand during the period when there is a shortfall in grid supply. Assuming modest incentives of about $200-250 per kW could encourage customers to install a greater volume of solar power systems than would otherwise occur, we estimate an average cost of about $1500-2000 per MWh, or about 6 to 8 times the available funds.

This is in large part due to the fact that the periods of solar generation are not coincident with the periods in the day and year when a shortfall might occur. Analysis of interval data for Enfield Zone Substation shows that solar generation is greater than about 25% of maximum panel capacity for only 3% of unmet load hours in winter, 46% of unmet load hours in summer and about 24% of overall unmet load hours. This is principally due to the later evening time of peak in both summer and winter. Note also that an increase in installed solar power systems of 100% in addition to the current projected trend is estimated to contribute only about 10 to 15% of the network support requirement. There is no indication that this is possible.

The combination of solar power with battery storage systems offers the potential to shift this generation to later in the day, but the costs of battery storage systems remain high relative to the available budget and takeup is very low with less 0.1% of customers currently with a battery storage system. Current prices for demand response from existing battery storage systems are about $1 per kWh, or about $1000 per MWh. This cost would be in addition to the incentives necessary to encourage sufficient new solar power systems to meet the demand shortfall requirement.

4.3.3 Customer energy efficiency

While this option is technically feasible and offers permanent reductions, improvements to customer energy efficiency are not estimated to offer a sufficiently cost efficient alternative, nor potentially a sufficiently material reduction in grid supplied demand during the period when there is a shortfall in grid supply. Assuming modest incentives of 10-15% of customer investment cost could encourage customers to install a greater scale of energy efficiency improvements than would otherwise occur, we estimate an average cost of about $1000-2000 per MWh depending upon the level of additionality and coincidence with the demand shortfall. At about 4 to 8 times the available funds, this solution is not likely to offer a cost competitive alternative.

4.3.4 Demand response (curtailment of load)

Customer curtailment of load is a common and effective technique for deferring network investment where the need is for short time periods and few days but has not been shown to be viable for the extensive hours and consecutive days of network support required for the network issue at Enfield zone substation.

Large customer demand response has historically been priced at $75-150 per kVA for 20-60 hours of dispatch per season while residential air conditioner demand response has been shown to be acceptable to small customers at incentive payment levels of about $150 to $250 per kVA for 20-30 hours of dispatch per season (excluding acquisition costs). Considering the costs of acquisition and requirement for support in two seasons each year, we would estimate the average cost for demand response to be about $2000 to $3000 per MWh for large customer demand response and greater than $5000 per MWh for small customer demand response. At a cost many times the available funds, this solution is not likely to offer a cost competitive alternative.

4.3.5 Dispatchable generation

Dispatchable generation is another common and effective technique for deferring network investment where the need is for short time periods and few days but has not been shown to be viable for the extensive hours and consecutive days of network support required for the network issue at Enfield zone substation.

Large customer dispatchable generation has historically been priced at $50-150 per kVA for 20-60 hours of dispatch per season. Considering the costs of acquisition and requirement for support in two seasons each year, we would estimate the average cost for this form of demand response to be well in excess of the available funds. Furthermore, as this solution commonly sources existing standby diesel generators; environmental compliance issues are likely to constrain the number of available operating hours.

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 of commercial scale battery storage solutions are unlikely to result in a material takeup of these systems by large customers. Recent surveys by Ausgrid of medium and large customers on issues related to investments in solar power, battery storage and energy efficiency has shown that these customers expect a return on investment which is not projected to be available for some time.

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 Non-Network Options Report has not been prepared in accordance with rule 5.17.4(c) of the National Electricity Rules.