Demand Management Investigation Report

Warringah STS

Summary

EnergyAustralia carried out an investigation of demand management (DM) options in the Warringah sub-transmission substation area in 2007. The aim was to determine if there were cost effective demand management measures that could defer the need for a $25m investment in a new 132/11kV zone substation, while maintaining network performance at the required level through the 2010 winter. This report concludes that cost effective demand management options are available.

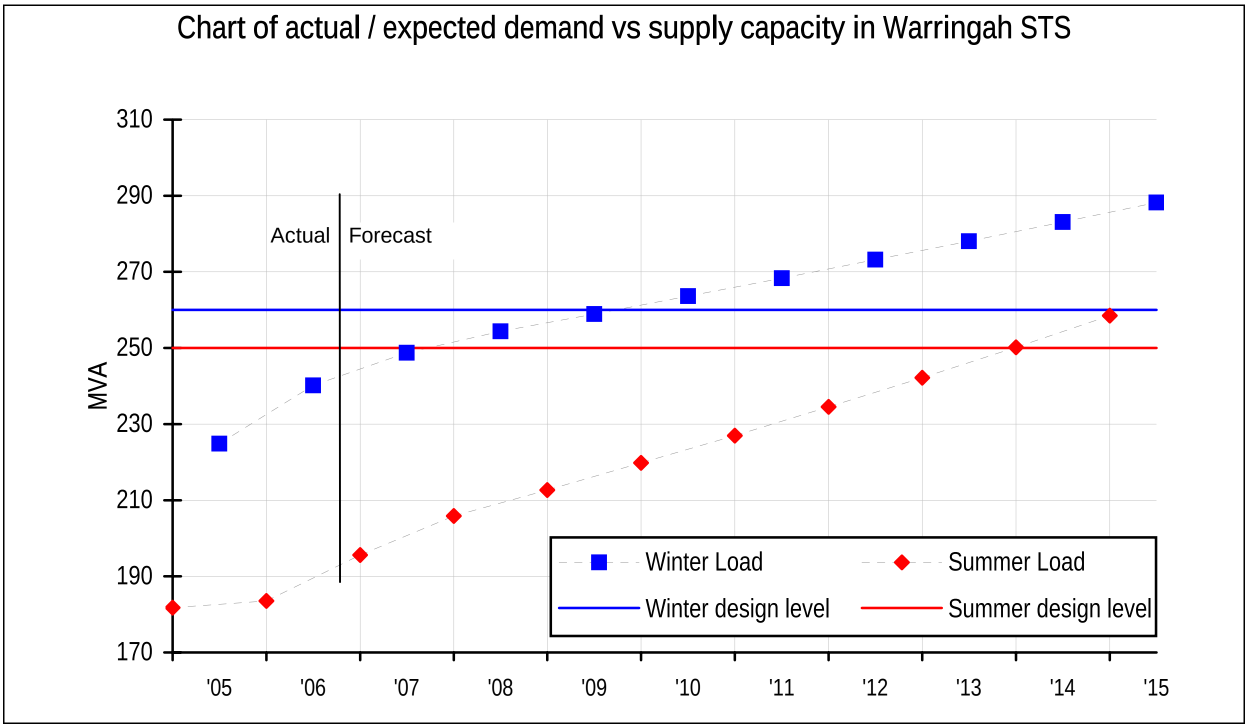
Balgowlah Screening Test Outcomes

A DM screening test completed in April 2006 concluded that to achieve a one year deferral of the proposed Balgowlah zone investment we would need to implement demand reductions totalling 2.7MVA before winter 2009. The savings from this deferral were estimated at $1.8m or $668/kVA.

Since then, revisions to forecast demands and the applicable design planning criteria have changed the critical drivers for this investment and the focus is now on Warringah Subtransmission Substation.

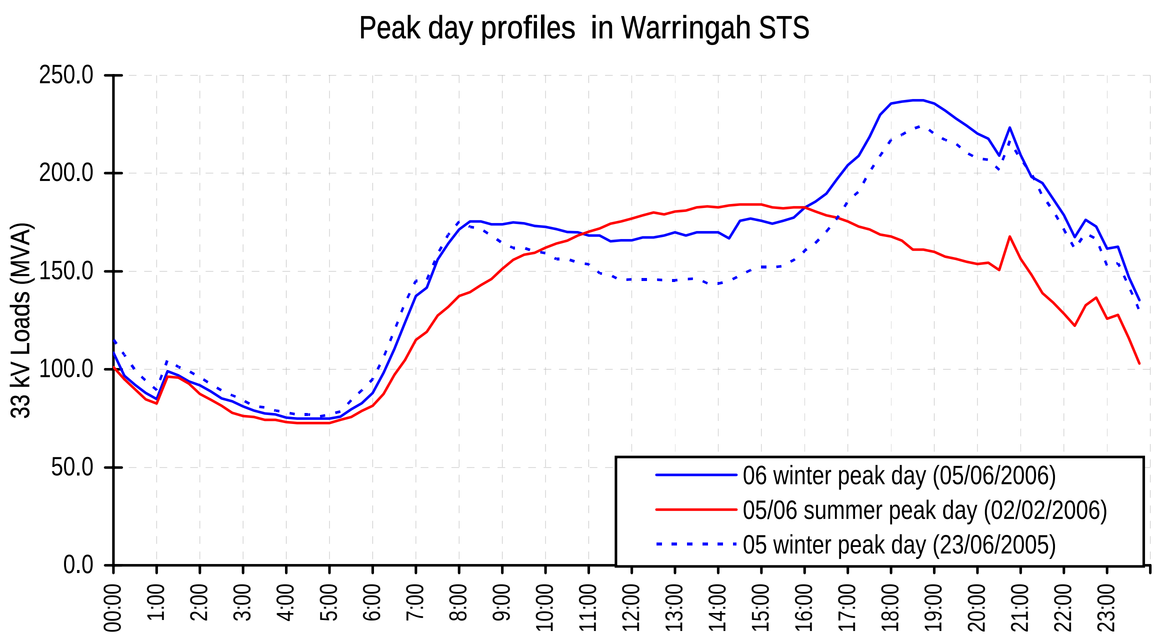
Warringah STS Demand and Capacity Forecasts

Based on the revised criteria and the forecast based on actual 2006 winter peak demand, neither Balgowlah nor Harbord zone substation require action until winter 2018. However, Warringah STS will be of concern in winter 2010.



Warringah STS Winter Peak Day Load Profiles

The following charts show the winter and summer peak load profiles at Warringah sub-transmission substation.



The load profiles suggest that residential loads dominate the winter evening peak demand. Any DM solution would need to be effective during weekday winter evenings between 5:30pm and 8:00pm. The load profiles of the top 10 days for winter in Appendix A show that the load profiles are quite consistent.

The peak daily load profiles illustrate that some off-peak hot water load is generally switched on at about 8:30pm. Because the off-peak hot water switching is scheduled and managed by a ripple control system, these electric loads can be re-scheduled by shifting the selected customers to different control channels or rescheduling switch-on time. EnergyAustralia will assess and make these changes if necessary. This investigation is focussed on the 5:30 to 8:00pm peak.

Revised DM Requirement

Under the revised circumstances, a 3.6MVA demand reduction in winter evening load would be required in winter 2010 to defer the supply side option for one year. The avoided distribution costs ($NPV) would be $2,520,000 ($700/kVA).

The age and condition of some of the equipment at Balgowlah zone substation means that it will need to be replaced at the end of 2010 in any case. Because of this, it is very unlikely that the project could be deferred for more than one year.

Demand Management Investigation

The overall investigation approach was to identify potential DM options, assess the likely size of the demand reduction and rank them based on their cost ($/kVA) to EA. The most cost-effective options might result in a feasible project. We identified major customers based on their average daily usage, visited the potential sites and collected information about their usage of energy and possible DM options. We also reviewed existing investigation reports from the Demand Management and Planning

Project in the Warringah STS area. Using all this information, we prepared a list of potential DM options for further investigation.

For each of the options we assessed the likely size of demand reduction that would result at the time of network peak at the zone substation. We also estimated the cost of implementing DM options to EnergyAustralia. Based on these estimates, we ranked the options and compared them to the potential savings from deferring the proposed supply side investment.

Identified DM options

- Power factor correction
- Relocatable generators
- Electric hot water conversion
- Commercial lighting upgrades and fixed dimming unit
- Customers' standby diesel generators
- Compact Fluorescent Lamp (CFL) and fuel switching program
- Potential load shifting and embedded generation at Sydney Sewerage Treatment Plant in North Head
- Potential for network support agreements with existing embedded generators

DM Options Analysis

a) Power factor correction

Where customer's loads exhibit poor power factor, peak demands on the network are higher than they would otherwise be. Based on actual electrical demand data from 2006, we identified that seven customers had poor power factor. The estimated potential demand reduction, effective and subtransmission level is about 100kVA in winter. This is low because the load profiles of the businesses suggest smaller impacts in winter evenings. From our experience, the estimated cost of facilitating the program is about $20,000 or $200/kVA.

b) Relocatable generators

EnergyAustralia has used relocatable generators to provide reliable temporary load reductions in other areas. We identified several potentially suitable locations for installation of up to four 1MVA generators. The estimated cost to EnergyAustralia would be approximately $1m or $250/kVA.

c) Electrical hot water conversion

Residential hot water loads, if not controlled under off peak tariffs, make a significant contribution to winter evening peaks. Load profile data suggest that each electric water heater contributes an average of 0.7kVA to the winter evening peak. Converting these installations to gas would remove this load.

There are approximately 71,000 residences in the area. About 41,000 of these have gas connected and 27,000 – 28,000 of these have gas hot water. We estimate 26,000 customers use off-peak electric hot water and the remaining 17,000 have continuously supplied electric hot water. A survey suggested that about half the customers with off-peak electric hot water in this area also have gas connected. This means that very few of the customers using continuous electric water heating have a gas connection. Marketing experience suggests that it would be very difficult to convince customers with no gas connection to convert to gas water heating, even with a very generous offer.

Modelling of likely take up of several offers suggested a potential demand reduction of 200kVA , which would cost about $124,000 or $620/kVA.

d) Commercial lighting upgrade and fixed dimming units for lighting

From the survey, we identified some commercial customers who have the potential to upgrade their existing light fittings or install voltage reduction units (dimming devices) on their lighting systems. The proposed lighting upgrade option is to change the existing light fittings with an efficient lighting system consisting of a single triphosophor lamp, a reflector and electronic ballast. The impact on winter evening peak demand from these commercial lighting projects is very limited because these lighting loads are not strongly coincident with the peak demand times we are targeting. The estimated total demand reduction would be about 195kVA. The net cost to EnergyAustralia is estimated to be $189,500 or $972/kVA.

e) Customers standby diesel generator

One respondent to our Consultation Paper suggested they could reduce peak load in Balgowlah area by using a customer's 500kVA standby diesel generator. The proposal did not provide any indication of cost.

We undertook further investigation of the site and found that the standby generator is currently configured as a standard standby arrangement with no synchronising capability. Based on the customer's expressed reliability requirements, a SCTT connection would need to be installed. The demand reduction would be limited to the customer's own load - about 280kVA in winter evenings. The estimated cost to EnergyAustralia to establish and use this capability would be approximately $175,000. This includes customer's main switchboard modifications, monitoring, dispatch equipment, project management, contracting and one year's operational cost. This translates to an average cost of about $632/kVA.

It would also be possible to use the full diesel generator capacity of 500kVA if the generator were able to be synchronised and run in parallel with export to the grid. This arrangement would provide an additional 220kVA demand reduction. However, the additional cost for full parallel connection to EnergyAustralia would be at least $120,000.

f) CFL and fuel switching program

We received a submission that proposes to promote the use of compact fluorescent lamps (CFLs) and converting cooking and heating appliances from electrical to gas in residences.

Based on our own assessment of customers' loads in the area, available information about residential dwellings and further discussions with the proponent, we estimated that an expectation of 1.2MVA demand reduction would be realistic in the Balgowlah area. We assessed the net cost for such a project as $1,782k.

g) Load shifting and embedded generation at Sydney Water treatment plant in North Head

The Demand management and Planning Project identified the potential for significant pumping loads to be shifted from the winter evening peak period. The potential peak demand reduction could be 3 - 4MVA for about two hours. We estimated that cost to EnergyAustralia would be $250,000 or $60 - 85 per kVA. In addition, there are two proposed generation projects – a 1.4MW biogas generator and a 2MW hydro mini-turbine. If a suitable network support agreement could be negotiated, these might be able to contribute to the necessary demand reductions. There are no clear precedents for the cost for such an arrangement. The projects are already committed and the cost to ensure they are managed in such a way to maximise the probability of providing reliable network support are not significant. We estimated a cost of $50/kVA for the purpose of analysis.

h) Belrose Landfill Gas generator

A 1MW landfill gas generator belonging to Energy Developments Ltd has been in operation at Belrose for some years. While this generator has generally exhibited predictable performance during network peak periods, no contractual arrangements are in place to ensure this remains the case in winter 2010. On this basis, network load forecasts assume the generator is not running during peak periods.

A suitable network support agreement could be negotiated which would enable this generator to be relied upon to provide network support. There are no clear precedents for the cost for such an arrangement. The project has been in place for some time and the cost to ensure it is managed in such a way to maximise the probability of providing reliable network support should not be significant.

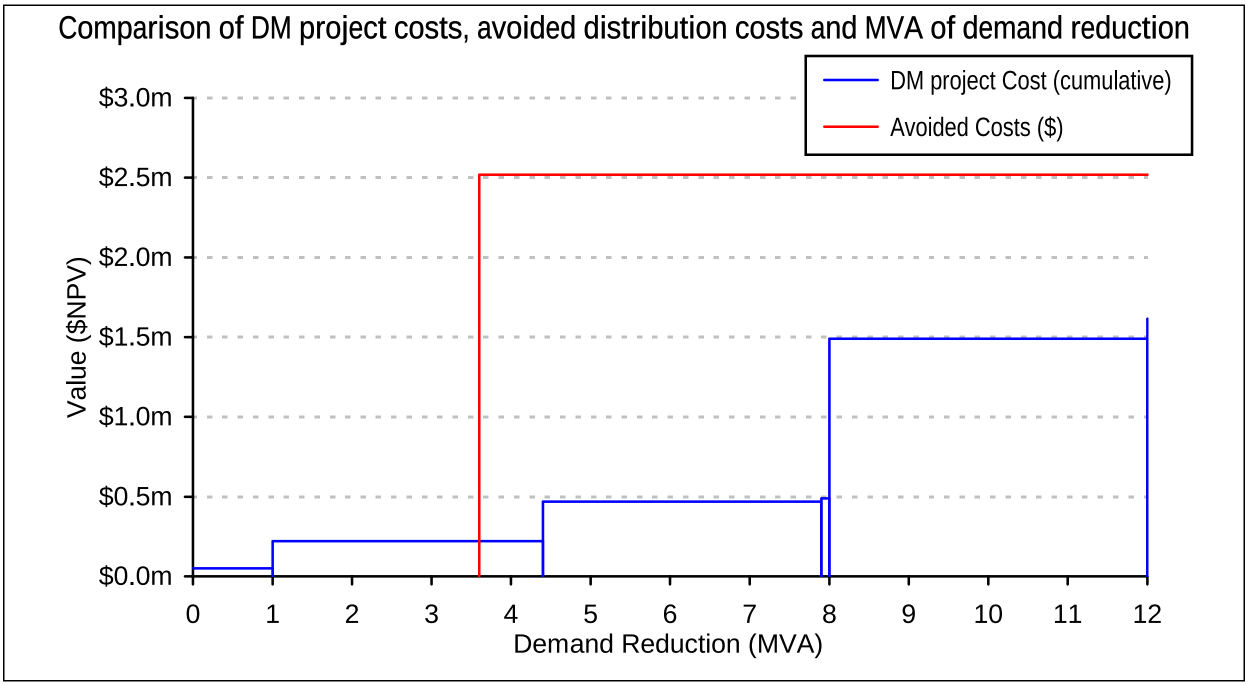
We estimated a cost of $50/kVA for the purpose of analysis.

Summary of DM Project Cost and Load Reduction

Based on our investigation, we have estimated the DM project cost and potential load reduction. The following table summary results of the studies. We ranked the options according to the cost to EA ($ per kVA).

DM Options for winter	Peak Load Reduction	Total cost to EA ($NPV)	Cost to EA ($/kVA)	No. of Customers Involved	Time for Implementation
Belrose Landfill Gas Generator	1MVA	$100,000	$50	1	1 year
Sydney Water embedded generators	Up to 3.4MVA	$340,000	$50	1	1 - 2 years
Sewerage pump load shifting	3 - 4MVA	$250,000	$60 - 85	1	1 – 1.5 years
Power factor correction	0.1MVA	$20,000	$200	7	0.5 - 1 year
Relocatable generators	4MVA	$1,000,000	$250	1	1 – 1.5 years
Electrical hot water conversion	0.2MVA	$124,000	$620	700	1 – 2 years
Customer standby generator (SCTT)	0.28MVA	$175,000	$625	1	1 – 2 years
Commercial lighting upgrade and fixed dimming unit for lighting	0.19MVA	$189,500	$972	8	1 – 2 years
CFLs & fuel switching program	1.2MVA	$1,782,000	$1,485	12,000	1 – 2 years

The chart below compares the cost and demand reduction impact of the identified options to the value of avoided distribution costs and DM requirements. Stacking the options from lowest relative cost to highest shows that sufficient demand reduction has been identified to achieve a one year deferral.



Feasible Options

On the basis of this analysis, we found that there are several feasible options that could achieve sufficient cost-effective demand reductions to achieve a one year deferral. A more detailed review of each of these was undertaken.

- **Load shifting at Wastewater Treatment Plant, North Head**

The North Head Treatment Plant has significant pumping loads associated with lifting wastewater to ground level for treatment from the underground sewage system. Discussions with Sydney Water identified that it would be technically feasible to manage the pumping loads to ensure that the load was reduced at specified times. This would be achieved by operating one less pump during the period, giving a load reduction of at least 3.3MW.

Further discussion with operational staff will be required to confirm this potential and determine the best operating regime and the means of notifying when we would require the load to be shifted. Indicatively, Sydney Water suggested they would need 24 hours notice so that they could ensure they could effectively manage the rescheduling.

We would need to develop and appropriate network support contract to ensure reliable operations and provide some reward to Sydney Water. If dispatch communications were required, we would also fund those costs. We do not expect that there would be any significant operational costs for Sydney Water. It may be most practical to modify the operating regime to have reduced load applying on all weekdays during winter 2010, rather that a notice – dispatch process.

We estimated the cost is about $250,000.

- **Embedded generation at Sydney Water, North Head**

Sydney Water informed us that their 1.4MW biogas cogeneration facility would be installed in this Christmas (2007). It is unclear how this is likely to be operated. The project is primarily driven by their desire to produce renewable energy to reduce their carbon emissions, so it would be expected to run as often as gas was available. The design embodies a small amount of storage which would enable some flexibility in operation, and Sydney Water believed it would be practical to operate it in such a way to ensure a reduction in net load during specified winter evening peak periods.

Again they suggested 24 hours notice would be necessary to ensure sufficient biogas was available during the critical period. The project is almost complete and requires no additional funding.

In addition, Sydney Water expect to install a mini-hydro generation facility that would generated energy from the falling water at the outfall side of the treatment works. Their current program suggests this will be commissioned in 2008. This may also be available for demand reduction in winter evening peak times. Again, this project is primarily driven by the desire to produce renewable energy, but operations would be strongly dependent on outfall flows. It is unclear whether there would be inherent storage capacity that would make the operation of this generator sufficiently manageable to ensure operation during winter evening peak times.

We have assessed this option as a lower probability than the biogas project, but similar requirements would need implemented to establish communications, operating protocols or appropriate operating and maintenance regimes. On this basis we have assessed this option as being able to deliver a 1MVA reduction reliably.

We estimated the cost is about $80,000 to contract the 1.4MW biogas generator and another $60,000 for the mini hydro generator, provided it can be demonstrated to be sufficiently reliable.

- **Customer power factor correction**

Our analysis of metering data showed just seven target sites for PFC in the area. Based on our review of the load profiles of the customers and the resulting probability of coincidence, this should result in a reduction of peak demand at the zone of 100kVA. This is low because the customers have predominantly commercial load profiles and their peak demands do not correlate well with the winter evening period. Total cost of EA to undertake such a program is estimated at $20,000, including all project management, customer contact and direct costs.

- **Belrose landfill gas generator**

We have confirmed that our forecasts do not assume that this generator will be running during the peak period. While historical records show that it has usually done so, sometimes at less than full output, we have no certainty over its continued operation or its future operating pattern.

Initial discussions with the owners of the generator show they would be willing to discuss network support options and that they expect to be operating through the 2010 winter.

There would be little in the way of additional cost for this adjustment to operations and we understand it would be technically feasible to ensure all maintenance was completed prior to the winter season and to operate the facility to ensure maximum likelihood of it being operational during the winter peak period. While we have not discussed likely cost, we believe it would be possible to negotiate a contract at a cost of $50,000

- **Relocatable generators**

EnergyAustralia has used leased diesel generators in other areas as a successful DM option. In the even that other less expensive options could not be delivered, this would provide a reliable project that would be under our control and could be delivered at a well-defined cost.

Identification of a suitable site is a critical element of this option. However, the area is large and there are several likely locations where we believe we could locate such a project.

Based on our experiences from similar project, we found that this option is technically feasible and commercially viable. Estimated cost, based on our current contracts for generator leasing and experience with previous projects is $1,000,000 for a 4MVA installation.

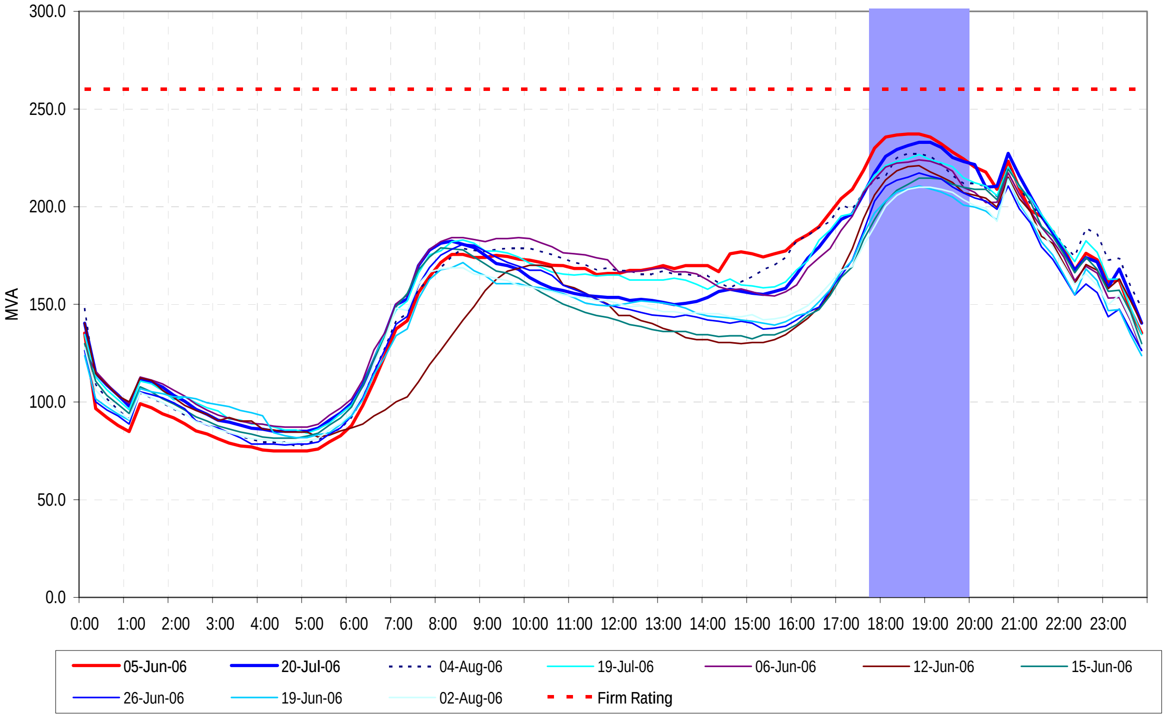
Conclusion

We identified several feasible DM options that could form a cost effective strategy that would defer the need for the investment for one year. Some of these options may not prove to be achievable, but we have several alternative strategy options available, each of which would be cost effective. Each of these options will be developed and a final project proposal comprising the most cost effective combination produced to enable approval to be given in early 2008 for implementation.

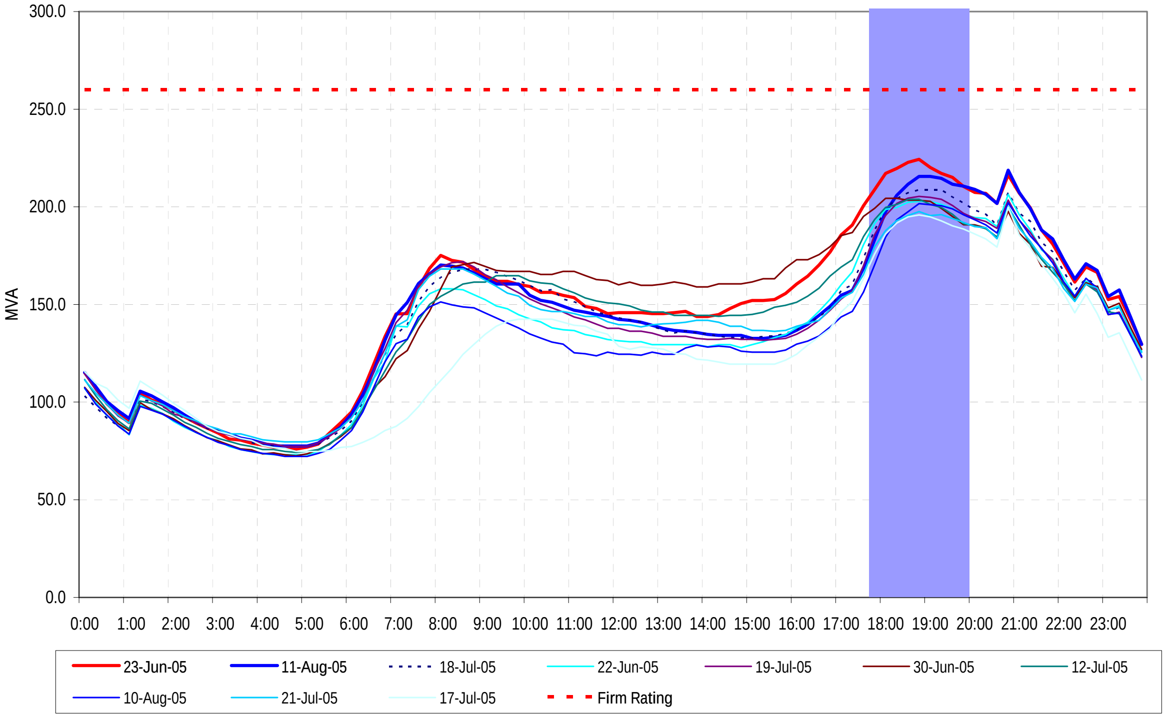
Appendix A: Additional Data

- Warringah STS load profiles of top 10 days in winter 2006 and 2005

Top 10 days load profiles in winter 2006



Top 10 days load profiles in winter 2005



Appendix B: Public Consultation

EnergyAustralia prepared the Balgowlah Demand Management Options Consultation Paper and advertised it in the Sydney Morning Herald and Manly Daily in June 2006. We also sent a notification to interested parties in the EA register. The Options Paper was also available on EA website for any interested parties to submit responses before the 31st August 2006.

The objective of this consultation was to invite responses from industry experts, consultants, manufacturers of energy efficient equipment, parties interested in demand management and any other member of the public who wished to suggest or offer any energy reduction option or alternative for investigation. We assessed all these options.

Results

We received three submissions with general information including a firm proposal.

No	Company	Proposed Technology	Proposed kVA demand reduction	Assessed net cost ($/ kVA)	Sites or Clients
1	Low Energy Supplies+ Services	Fuel-switching Distribution of compact fluor lamps	2,700kVA	Proposed $660/kVA	12,000 residents
2	Energy Response	Advanced control technique Load shedding	500kVA	N/A	1 commercial site
3	Intelligent Energy Solutions Pty Ltd	Active harmonics filters Power factor correction	N/A	N/A	N/A

Appendix C: Specific Site Investigations

As part of the scoping investigation, we visited and analysed 33 major sites in Warringah area. The purpose of the site survey was to identify any demand management opportunities that could help reduce the peak demand. The list of customers is shown below.

No.	Customers' Name
1	Balgowlah RSL Club
2	Harvey Norman, Balgowlah
3	Coles Myer, Balgowlah
4	Blackmores Ltd
5	Telstra site, Balgowlah
6	Manly Freezers
7	Franklins Ltd, Balgowlah
8	Tabco Pty Ltd
9	Kumar Motors P/L
10	Mykspen Pty Ltd
11	BP Australia, Balgowlah
12	Department of Education & Training
13	Northern Sydney Area Health Service - Dalwood House
14	Freedom Group Ltd
15	Balgowlah Public Heights
16	Sydney Water treatment plant in North Head
17	WARRINGAH AQUATIC CENTRE
18	Optus Earth Station – Belrose
19	Optus Exchange – Belrose
20	TELSTRA site - OXFORD FALLS
21	Warringah Mall
22	Woolworths – Warringah Mall
23	Big W - Warringah Mall
24	David Jones - Warringah Mall
25	Form-rite Plastics
26	Coles Myer Ltd – Brookvale
27	Warringah Rugby League - Manly
28	TAFE – Brookvale
29	RSL VETS Retirement Village
30	Dee Why RSL Club
31	Coles Myer Ltd – Forestville
32	Manly Pacific International
33	Warringah Aquatic Centre

Appendix D: DM Screening Test

DEMAND MANAGEMENT SCREENING TEST

Balgowlah

Current Supply Arrangements

Balgowlah zone substation consists of two 33/11kV transformers. It is currently supplied via a 33kV feeder S01, with backup supply from from feeder S10, both from Warringah Sub Transmission Station. S01 is also the backup feeder to Killarney zone substation.

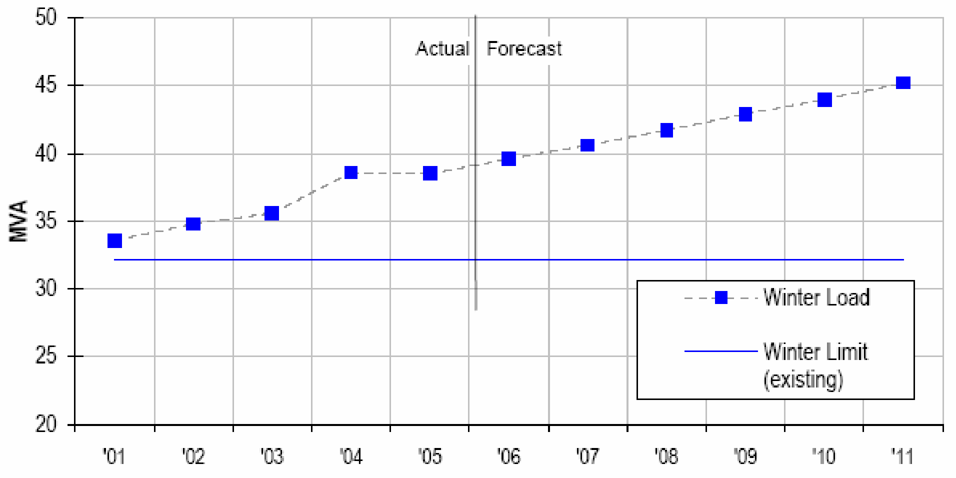
While it can supply up to 40.6MVA, the maximum recommended load on Balgowlah substation is limited by the transformer ratings to 30.8MVA in summer & 32.1MVA in winter. The 33kV feeder S01 supplying Balgowlah zone substation (and providing backup for Killarney zone substation) can supply 47.2MVA in winter and 41.4MVA in summer.

The Balgowlah zone substation supplies Balgowlah, North Balgowlah, Seaforth, Clontarf, Balgowlah Heights, Fairlight and Manly Vale. The Killarney zone substation supplies Forestville and Killarney Heights.

Supply Capacity and Demand Forecast

The Balgowlah zone is primarily residential and the peak load is during winter from 7pm to 9pm. This winter peak is the only season in which Balgowlah zone substation is forecast to be of concern. The forecast peak demand for the Balgowlah zone in winter 2006 is 38.8MVA, which exceeds the acceptable load on the substation. The winter peak demand is forecast to continue to grow, as shown in the chart below.

Chart of actual / expected demand vs supply capacity at Balgowlah Zone



Feeder S01 (to Balgowlah zone) provides back up to Killarney zone, hence in an emergency feeder S01 would need to provide the total load of both zones. This total load will be 57.2MVA in winter 2006 which is well above the feeder's recommended capacity of 47.2MVA. This total load is also forecast to continue to grow.

Appendix D: DM Screening Test

Balgowlah zone substation has major equipment which is approaching the end of its useful life. All major equipment at the substation is recommended for replacement within the next ten years, and all switch gear within 5 years.

Supply Strategy Option

The default supply system solution includes three parts:

A) Transfer 10MVA of the load in Balgowah to the Harbord zone substation at a cost of $4.5million. A final decision on whether to do this needs to be made as soon as possible, with commissioning proposed for the end of 2006.

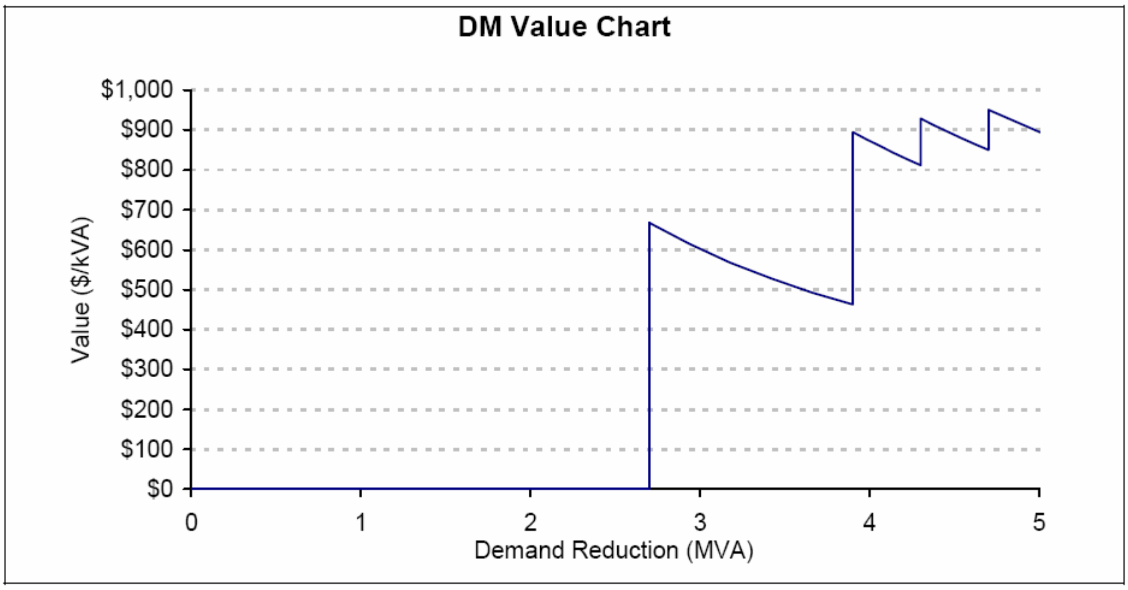
B) Install a new 33kV feeder in parallel to S01 at a cost of approximately $7million. A final decision on whether to do this needs to be made by late 2006, with commissioning proposed for winter 2007.

C) Construct a new 132/11kV zone substation to replace the existing Balgowlah zone substation at a cost of approximately $25million. A final decision on whether to do this must be made by about mid 2007, with commissioning planned by the end of 2009.

Required Demand Management Characteristics

An analysis of a number of different scenarios has shown that at a minimum, a demand reduction of 2.7MVA in Balgowlah before winter 2009 would defer the construction of the new 132/33kV substation by 1 year, making a saving of approximately $1.8million ($668/kVA). A DM investigation would have until mid 2007 to determine whether this much reduction is possible. This scenario would not defer any of the other parts of the supply strategy.

The analysis also showed that larger amounts of demand reduction could defer various parts of the supply options by different numbers of years. The values of some of these scenarios are shown in the graph below:



Appendix D: DM Screening Test

Recommendation

Based on this analysis it is considered reasonable to expect that it may be cost-effective to postpone the proposed new substation and possibly the new feeder by implementing demand management strategies. None of the scenarios analysed showed that it would be reasonable to expect that it may be cost-effective to postpone the 10MVA load transfers.

A demand management investigation will be undertaken involving a desktop investigation of existing residential demand management programs, and a public consultation. The investigation will focus on deferring the zone substation and the new feeder (parts B and C), and not on deferring the 10MVA load transfers (part A).

We have also identified a requirement to address load growth on certain 11kV feeders in Balgowlah zone. Any demand management solutions for the 11kV feeder loads may also contribute to reducing critical loading at Balgowlah zone and these investigations will be conducted jointly.