DEMAND MANAGEMENT SCREENING TEST

Kurri / Tomago Load Area

Please note: This screening test has been prepared in May 2004 to demonstrate the outcome if a screening test had been carried out at the end of 2002 based on data available at that time.

Current Supply Arrangements

Kurri and Tomago are 132/33kV subtransmission substations that supply an area generally north and west of Newcastle via a series of 33/11kV zone substations. Because of the interrelated nature of the areas served by these two stations, a strategic decision has been taken to consider solutions to the emerging issues in these areas jointly.

Kurri supplies the majority of the Maitland and Cessnock local government areas including the main centres of Maitland, East Maitland, Cessnock, Pokolbin, Kurri, Branxton and Rutherford. Key issues include residential development around Maitland and growth in tourism and wine processing in the Cessnock area.

Tomago supplies the majority of the Port Stephens local government area, including the main centres of Tarro, Raymond Terrace, Medowie, Williamtown, Tanilba Bay and Nelson Bay. Key issues are substantial residential development at Nelson Bay, Medowie and Raymond Terrace and commercial / light industrial development around Williamtown and Tomago.

Peak demands at Kurri STS are heavily biased toward summer, while demands at Tomago are similar in both summer and winter. At East Maitland, both summer and winter demands are significant, however summer growth rates are substantially higher than winter rates and summer will continue to be the critical period. Tarro is strongly summer peaking.

Constraints on the system are at several levels. The main constraints of relevance in this load area are at Kurri STS, Tomago STS, and at zone substations at East Maitland and Tarro. A minor issue at Maitland Central could also have relevance.

Supply Capacity and Demand Forecast

In the near term, several initiatives have been committed to in order to manage risks. These include load transfers from Branxton and Cessnock to Rothbury and moving Branxton to Singleton 66kV (relieving Kurri STS), reconnecting Kooragang to Waratah STS (relieving Tomago STS). At zone level they include load transfers from East Maitland to Rutherford, and from Tarro to a temporary Thornton zone.

Risk criteria for the 132kV system require strict application of the n-1 planning criteria. At zone substation level, a 1% risk tolerance is considered acceptable (assessed as a value 117% above the cyclic firm rating in these cases). The following tables of summer loading and rating data show the expected loading on these four system elements based on current forecasts (as at April 2002), allowances for committed actions and relevant ratings including risk tolerance where applicable.

Element	Risk Rating	2000/1	2001/2	2002/3	2003/4	2004/5	2005/6	2006/7
Kurri	136	**170**	**161**	**151**	**155**	**160**	**166**	**172**
Tomago	136	**157**	126	119	123	129	135	**142**
East Maitland	32	31.3	**34.0**	**32.8**	**34.2**	**35.8**	**37.2**	**38.8**
Tarro	27	**32.8**	**34.0**	25.2	26.1	27.0	**29.1**	**30.6**
Maitland Central	26	21.0	20.9	23.4	24.1	24.9	25.7	**26.4**

Supply Strategy Option

The proposed investments – A new STS at Beresfield by summer 2004/5 and a new permanent zone substation at Thornton by summer 2005/6 will reduce demands by 43MVA at Kurri in 2004/5, 38MVA at Tomago in 2004/5, 12MVA at East Maitland in 2005/6 and 3.5MVA at Tarro in 2005/6. The following table shows the expected summer loadings assuming these investments proceed. Note the transfer of some load from Maitland Central to East Maitland for 2006/7.

Element	Risk Rating	2000/1	2001/2	2002/3	2003/4	2004/5	2005/6	2006/7
Kurri	136	**170**	**161**	**151**	**155**	117	121	119
Tomago	136	**157**	126	119	123	91	95	99
East Maitland	32	31.3	**34.0**	**32.8**	**34.2**	**35.8**	25.1	31.0
Tarro	27	**32.8**	**34.0**	25.2	26.1	27.0	25.7	26.6
Maitland Central	26	21.0	20.9	23.4	24.1	24.9	25.7	21.5

Key strategy elements, costs and approximate timing of cash flows are listed below:

Measure	**Cost**	**Timing**	**Impact**
Relocate fdr 860	$0.5m	2002	Part of Thornton 33kV route
33kV CBs at Tarro	$0.6m	2002/3	Replacement of aged equipment
New 132/33kV STS at Beresfield	$16.5m	2004	Relieve Kurri & Tomago
33kV feeders	$3.5m	2004/5	Part of Beresfield STS project
New zone substation Thornton	$7m	2005	Relieve ~25MVA from EM & Tarro
Replace 33kV fdr 3152	$0.2m	2005	Enables subsequent upgrade of Tarro rating (not material)
Capacitors at East Maitland	$0.7m	2005	Demand reduction (3MVA)
Capacitors (12MVAr) at Tarro	$0.7m	2006	Demand reduction (3.3MVA)
Replace Tarro switchroom	$2m	2007/8	Increase firm capacity to 29MVA

The key investments to be considered are the Beresfield STS ($16.5m in 2004), associated 33kV feeders ($3.5m in 2004/5) and the Thornton Zone Substation ($7m in 2005). Timing of the two capacitor investments is indicative only and would be required within the current investment horizon only if demand increases above forecast.

In order to achieve a deferral of these investments, a decision would need to be made by early 2003. Otherwise a decision will need to be taken to proceed with the supply options to avoid unacceptable deterioration of supply reliability and potential load shedding.

Required Demand Management Characteristics

A DM solution applied by 2005 would be able to defer the Beresfield STS investment by one year if it reduced demand at Kurri by 24MVA during peak summer times. Based on load profiles of its constituent

zones this peak is most likely to occur during summer afternoon / early evening, suggesting a strong component of residential air conditioning. Some impact on winter demand may also be necessary. Tomago is not constrained until 2007.

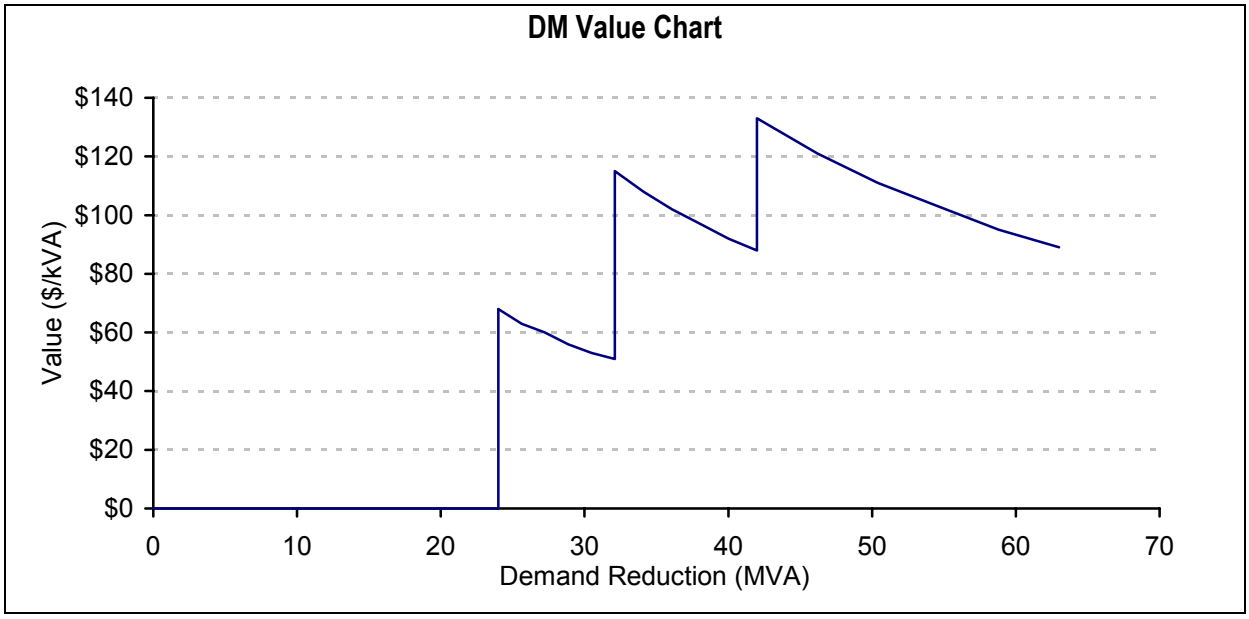
Note that this analysis has not considered any practical issues that might arise from delaying Beresfield STS while not delaying the Thornton zone substation – this is assumed to be possible.

To defer the investment another year (to 2006) would require an additional 6MVA reduction at Kurri (total 30MVA – again during summer). However this would also mean that the Thornton Permanent zone substation could not be connected, so a 5.2MVA reduction would be required at East Maitland to defer this investment as well (by one year). East Maitland peak demands occur during summer afternoons and winter evenings, with the summer demands more critical. Any DM solution would need to focus mainly on the summer peak, but may need to provide some reductions during winter evenings as well. Since East Maitland would be part of the Kurri demand this would offset the demand management requirement at Kurri. In addition, 2.1MVA of demand reduction (in summer) at Tarro would be required. This would slightly reduce Tomago demand as well.

A three year deferral (and two years for Thornton) would require a total of 36MVA at Kurri, including 7.2MVA from East Maitland / Maitland Central, and a total of 6MVA from Tomago, including 3.6MVA from Tarro. Seasonal and timing characteristics would be similar.

The available load profiles suggest that the strongest demand driver is probably residential air conditioning, which is a difficult segment to address. Significant commercial and industrial loads also exist and might provide more useful opportunities.

Based on the available information, the value of deferral for various levels of demand reduction is represented in the diagram below. Each year's deferral represents between $1.6m and $2m (present value in 2003). This translates to a value of $68/kVA for one year deferral, rising to $115 and $133 for larger demand reductions and greater lengths of deferral.



The required demand management for at least one year's deferral would need to be delivered before summer 2004/05 to maintain acceptable reliability risks.

The required amount of 24MVA represents 15% of the load on the Kurri STS. This is a very large amount of demand reduction. However, the area from which this might be found is large and should offer a range of options. Reductions of this size are very likely to require a relatively large number of options involving a large number of customers. The summer evening bias in the profile presents some difficulty, as most industrial sites and many commercial sites offer few opportunities that are strongly coincident with this time. Little experience with residential DM options is available on which to base estimates of likelihood of success, cost and timing. However, DM measures to address residential loads are generally agreed to take longer to implement and be higher cost due to the large number of transactions required. Overall, it is considered that securing the required amount of demand reduction with the appropriate characteristics would be difficult, but not impossible.

Given the issues at East Maitland, it would also be strongly preferable if a large amount of the DM was located in this area. While this is not a necessary requirement for delaying Beresfield STS only one year, any further deferral would require this to be the case and as noted above any practical issues associated with concurrently constructing Beresfield STS and Thornton Zone have not been considered. The effect of restricting the area from which a significant portion of the DM would need to be drawn would make the acquisition of the required amount more difficult.

The timeframe for certainty is extremely short, as a firm decision to defer the investment would need to be made by early 2003 at the latest to avoid jeopardising the timely delivery of the supply options. This makes residential DM options unlikely and would also make finding sufficient DM from any sources very challenging.

The value for the first stage of deferral is not very high ($68/kVA), and previous investigations seeking DM options at this level have not proven to find significant amounts. The higher values for large amounts (over $100/kVA) are better, but remain challenging – especially as the required amount is also larger.

The absolute volume of DM required is large. The time of day and season characteristics it would need to match restrict the available options. The timeframe in which it would need to be identified and proven is very short. The value available for DM is moderate at best. Based on these factors and our experience with other investigations, it is considered highly unlikely that sufficient effective DM options would be identified in an investigation to enable a cost-effective deferral of any part of this investment strategy. Given these factors, it is considered unreasonable to commit the resources and potentially delay development while a proactive DM investigation is undertaken

Recommendation

Based on this analysis it is considered unreasonable to expect that it would be cost-effective to postpone the expansion by implementing demand management strategies. We recommend that no further specific investigation of demand management options be pursued with respect to the proposed Beresfield STS and Thornton Zone Substation Projects.

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Footnote: The DM value calculations have been re-cast using the revised costs data from the January 2003 Hunter Proposed Capital Works Plan. This resulted in an increased value of DM options for the above scenarios to $94/kVA, $152/kVA and $174/kVA respectively. Although these increased values would increase the amount of DM likely to be available, this impact is not sufficient to overcome the other issues that support the recommendation and it remains robust to this change.