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500kV Upgrade: Preliminary Regulatory Test Analysis

A Report for TransGrid

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Executive Summary

TransGrid has identified that continuing increases in summer peak demand, coupled with a tightening of the supply-demand balance for generation in NSW, are expected to result in network reliability issues in the Newcastle - Sydney - Wollongong area in the near future; by 2008/09 at the earliest.

The pattern of generation investment that occurs in NSW will have a significant impact on the date at which the expected network reliability issues arise. Consequently, the regulatory test assessment considers a number of different generation scenarios.

TransGrid has commissioned NERA to carry out an initial regulatory test analysis. The network augmentation proposed by TransGrid is necessitated solely by the inability to meet minimum network performance requirements, which are determined by considering the implications of an outage of a critical network element. We have therefore applied the reliability limb of the regulatory test in conducting this assessment.

It appears at this stage that in several scenarios, action would need to be taken in 2008/9 to ensure that minimum network performance requirements continue to be met. TransGrid has advised that the currently identified network solutions would only be able to be operational by 2009/10. Consequently, our assessment has been restricted to two combination options, both of which include a non-network component in 2008/9 (either generation or demand management or both) to ensure that minimum network performance requirements are met in that year, followed by TransGrid's proposed network augmentation (the '500kV upgrade'). Under Option 1, the augmentation comes into effect in 2009/10. Option 2 includes a further year of network support to defer the 500kV upgrade until 2010/11.

Since there are currently no firm proponents for specific generation or demand-side management (DSM) options at this stage (and to avoid releasing information relevant to commercial negotiations), we have modelled both options on an indicative basis using a 'generic' non-network alternative.

The table below summarises the results of the financial modelling for the two options.

Table E.1: Comparison of Option Results (present values)

Options	Costs: PV ($M)	Rank
Option 1: 500kV Upgrade in 2009/10	320	2
Option 2: Upgrade deferred to 2010/11	317	1

Our preliminary assessment is that Option 2 minimises the present value of costs (compared with Option 1); consequently, it appears that Option 2 is likely to satisfy the regulatory test.

However, it should be borne in mind that the costs of the generic non-network alternative are at this stage merely indicative, and need not reflect the final proposed contract prices, which

will be used in the final regulatory test assessment. Accordingly, significant emphasis should not be placed on the result at this stage.

Nevertheless, since the results indicate that the present values of the two options are close together, TransGrid cannot at this stage eliminate either option from consideration. This underlines the importance of TransGrid's discussions with potential providers of generation and demand side management, and implies that those discussions should be undertaken with a number of potential providers, with a view to the possible implementation of non-network alternatives in both 2008/09 and 2009/10.

1. Introduction

TransGrid has identified that continuing increases in summer peak demand in NSW, coupled with a tightening of the supply-demand balance for generation in NSW, are expected to result in network reliability in the Newcastle - Sydney - Wollongong area falling short of minimum network performance requirements in the near future; by 2008/09 at the earliest.

TransGrid has identified a range of potential options, comprising network augmentation (the '500kV upgrade') with non-network support (DSM and/or a network support contract with a generator), to enable minimum network performance requirements to continue to be met past this date.

TransGrid has commissioned NERA to carry out an initial regulatory test analysis of these options. This report presents our preliminary assessment, which has been undertaken in accordance with the requirements in clause 5.6.6 of the National Electricity Rules ('NER') and the AER's regulatory test.

This initial regulatory test analysis is being issued together with TransGrid's Application Notice as part of the required consultation process set out under clause 5.6.6 of the NER. In particular, the non-network options considered in this analysis are indicative only at this stage, with no firm proponents. It is envisaged that the analysis presented in this report (including the detailed identification of options) will be refined following consultation and further commercial discussions between TransGrid and potential providers of non-network solutions. As a result, significant emphasis should not be placed on the results of the present value analysis at this stage.

1.1. Structure of the Report

The remainder of this report is set out as follows:

Section 2 sets out the requirements under the Rules and the regulatory test for intra-regional network augmentation of the type proposed by TransGrid.

Section 3 provides a discussion of the anticipated inability of the existing network to meet minimum network performance requirements.

Section 4 discusses the role of market development scenarios under the regulatory test, and sets out the market development scenarios adopted for the analysis.

Section 5 outlines alternative options for addressing the inability to meet minimum network performance requirements in the Newcastle - Sydney - Wollongong area.

Section 6 details the assumptions underlying the regulatory test analysis, including the discount rate, asset lives and relevant costs. Section 6 also outlines the sensitivity tests undertaken to ensure the robustness of the modelling results.

Section 7 presents the results of NERA's preliminary regulatory test analysis for each option under each market scenario, including the sensitivity analysis conducted.

Section 8 discusses the main conclusions drawn from the results.

Appendix A presents the detailed results of the preliminary regulatory test analysis.

2. National Electricity Rules Requirements

2.1. Rules Requirements for Intra-regional Network Augmentation

The NER establishes the framework for the planning and development of transmission networks within a region.[1] It establishes requirements for the planning process Transmission Network Service Providers (TNSPs) must conduct to identify the need for network augmentations and the annual planning report they must produce to communicate that need to market participants (NER Clause 5.6.2A).

The 500kV upgrade proposed by TransGrid is a new large transmission network asset.[2] Where a TNSP wishes to establish a new large transmission network asset, the NER requires the TNSP to assess alternatives (including generation and DSM measures) before conducting any network augmentation.[3] Clause 5.6.6 (b) (3) of the NER requires TNSPs to apply the principles in the regulatory test to obtain a ranking over the network augmentation and all reasonable alternatives.

2.2. The Regulatory Test

The regulatory test is a form of cost-benefit analysis for assessing alternative investment options. The test comprises two distinct limbs:

- the 'reliability limb', which is intended for use in assessing network investments undertaken to meet minimum network performance requirements, and is set out in clause (1)(a) of the test; and
- the 'market benefits limb', for use in assessing other network investments, set out in clause (1)(b).

2.2.1. The reliability limb of the regulatory test

The reliability limb of the regulatory test is set out in clause (1)(a), as follows:[4]

(1) *"An option satisfies the* regulatory test *if:*

(a) *in the event the option is necessitated solely by the inability to meet the minimum network performance requirements set out in schedule 5.1 of the Code or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction - the option minimises the present value of* costs*, compared with a number of* alternative options *in a majority of* reasonable scenarios*;*

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1 NER Chapter 5.6.

2 A new large transmission network asset is defined as any network asset involving capital expenditure of more than $10 million.

3 NER 5.6.6 (b)(1)(iii)

4 Extract from Version 2 of the regulatory test, as revised by the ACCC in its 2004 review of the test.

As indicated in this quotation, the reliability limb of the regulatory test can be applied to a proposed augmentation in the event that it is necessitated solely by the inability to meet minimum network performance requirements. The 500kV upgrade proposed by TransGrid is necessitated solely by the inability to meet minimum network performance requirements, as described in Section 3. We have therefore applied the reliability limb of the regulatory test in conducting this assessment.

2.2.2. The 2004 revision of the regulatory test

In its 2004 review of the regulatory test,[5] the ACCC introduced significant changes to the 'reliability limb' of the regulatory test, which modify the way in which this limb of the regulatory test is applied.

The revised version of the test makes a more explicit distinction between the two limbs by restricting the consideration under the reliability limb (ie, 1(a)) to the 'present value' of costs (instead of the previous reference to 'net present value'); and sets out a non-exhaustive list of applicable costs (in clause 2). Specifically, clause 2 states that:

> "Costs *means the total cost of an option (or an* alternative option*) to all those who produce, distribute, or consume electricity in the National Electricity Market.*
>
> *In determining the* costs*, the analysis may include, but need not be limited to, the following:*
>
> *(a) costs incurred in constructing or providing the option;*
>
> *(b) operating or maintenance costs over the operating life of the option;*
>
> *(c) the cost of complying with existing or anticipated laws, regulations and administrative determinations, such as those dealing with health and safety, land management and environment pollution and the abatement of pollution (including greenhouse gas abatement). An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost.*
>
> *(d) other costs that are determined to be relevant to the case concerned."*

Clause 8 of the regulatory test provides that only direct costs that can be measured in terms of financial transactions in the market may be included.

The revised wording of the regulatory test has implications for the form of the analysis. In particular, the costs to be taken into account are now limited largely to the costs that are directly incurred in constructing, operating and maintaining each option, as well as environmental costs and subsidies. Avoided costs (ie, benefits) arising from the impact of the option on the wider electricity market are not included in the analysis.

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[5] On 11 August 2004, the Australian Competition and Consumer Commission (the 'ACCC') released "Version 2" of the regulatory test along with its report, *Decision: Review of the regulatory test for Network Augmentations*.

In the course of preparing this report and previous work for TransGrid, NERA has discussed the interpretation of the reliability limb with staff from the AER (and previously the ACCC's electricity group). AER staff have confirmed that the analysis should now be restricted to direct costs (with the exception of environmental subsidies), and should not include avoided costs.

2.2.3. Assessing non-network options

The regulatory test requires that all options assessed under the reliability limb must have a proponent.[6] At this stage, no firm proponents have come forward for either generation or DSM options to address the anticipated inability to meet minimum network performance requirements. TransGrid has, however, highlighted the emerging inability to meet minimum network performance requirements in its September 2005 Needs Statement.[7] TransGrid has received indications of interest from potential proponents of three generation options as a result (discussed further in Section 5).[8] In addition, TransGrid also issued an RFP for non-network options in March 2006 and has appointed CRA to undertake discussions with potential DSM proponents to gauge the feasibility of undertaking DSM to defer the need for network augmentation. Discussions between CRA and potential DSM proponents are currently on-going.[9]

Given the potential for proponents of non-network options to emerge prior to TransGrid's final regulatory test decision, we believe it is appropriate to consider non-network options in this initial regulatory test application on an indicative basis, despite the lack of a firm proponent at this stage. We believe this approach will assist the consultation process and TransGrid's discussions with potential non-network proponents.

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6 Regulatory test clause 3(a)(i)(A)

7 TransGrid, Sept 2005, *Emerging Major Transmission Network Limitations in Supplying the Newcastle-Sydney-Wollongong Load Area, Needs Statement*

8 TransGrid, March 2006, *Request for Proposal, Provision of Non-Network Alternatives for the Newcastle-Sydney-Wollongong Load Area*

9 CRA International, May 2006, Preliminary Status Report: *Assessment of Non-Network Solutions for the 500 kV Project*

3. Anticipated Inability to Meet Minimum Network Performance Requirements

This section outlines the minimum network performance requirements that the transmission network supplying the Newcastle-Sydney-Wollongong area is required to meet. More technical detail can be found in TransGrid's Application Notice.

The 'reliability limb' of the regulatory test may be applied:

> ' in the event the option is necessitated solely by the inability to meet the minimum network performance requirements set out in schedule 5.1 of the NER or in relevant legislation, regulations or any statutory instrument of a participating jurisdiction' (regulatory test (1)(a))

The transmission network supplying the Newcastle-Sydney-Wollongong area faces two main limitations:

1. Overloading on one of the 330kV transmission lines between the Hunter Valley power stations (Liddell and Bayswater) and the Newcastle area, following an outage of the other line; and

2. Inadequate voltage levels in the Sydney area 330kV system, together with an inability to adequately control these voltages following an outage of one of a number of critical 330kV circuits supplying the Sydney area.

Currently both of these limitations can be managed by altering the dispatch pattern of generation in the NEM. However, with the growing NSW demand for electricity and the increasing dependence on existing generation sources (which reduces the scope to redispatch generation to manage network limitations) it is expected that these limitations will become a critical reliability issue in the near future; possibly as soon as the summer of 2008/09.[10]

Schedule 5.1 of the Rules requires that:

> S5.1.2.1: ***Network Service Providers*** must plan, design, maintain and operate their ***transmission networks*** and ***distribution networks*** to allow the transfer of power from ***generation units*** to ***Customers*** with all ***facilities*** or equipment associated with the ***power system*** in service [..]

We interpret the reference to 'transfer of power' to mean 'the transfer of all reasonably forecast maximum power'. That is, the minimum standard set out in Schedule 5.1 is for the full transfer of all reasonably forecast customers' power demands, with all network elements in place (in the absence of an alternative standard being set out in a customer's connection agreement).

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[10] The exact date that these limitations will become critical is uncertain, because it depends on future maximum demand levels and the future pattern of generation investment in NSW. This uncertainty is taken into account in the regulatory test analysis through the use of alternative market development scenarios – see section 4.

Under both Chapter 4 of the NER and the National Electricity Law, NEMMCO has responsibility to maintain power system security, in line with the principles set out in Clause 4.2.6 of the NER.[11] The first of these system security principles is:

> 4.2.6(a) To the extent practicable, the *power system* should be operated such that it is and will remain in a *secure operating state*.

The definition of 'secure operating state' is set out in the NER as follows:

> 4.2.4(a) The *power system* is defined to be in a *secure operating state* if [..]:
>
> (1) The *power system* is in a *satisfactory operating state*; and
>
> (2) the power system will return to a *satisfactory operating state* following the occurrence of a *single credible contingency event* in accordance with the *power system security and reliability standards.*[12]

We interpret 4.2.4(a)(2) above to mean that the system must immediately return to a satisfactory operating state, following the occurrence of a single credible contingency event.[13]

Clause 4.2.3(c) of the NER defines 'single credible contingency event' as follows:

> A '*single credible contingency event*' means an individual *credible contingency event* for which a *Registered Participant* adversely affected by the event would reasonably expect, under normal conditions, the design or operation of the relevant part of the *power system* would adequately cater, so as to avoid significant disruption to *power system security*. [Emphasis added]

Under clause 4.2.3(b), a 'credible contingency event' means a contingency event which NEMMCO considers has a reasonable possibility of occurring in the surrounding circumstances and includes:

> the unexpected *disconnection* of one major item of *transmission plant* (ie, *transmission line*, *transformer* or *reactive plant*) other than as a result of a three phase electrical fault anywhere on the *power system.* (4.2.3(b)(2))

The limitations on the transmission network supplying the Newcastle-Sydney-Wollongong area mean that in the relatively near future (ie, sometime from 2008/9) the actual occurrence of a single credible contingency event would result in the power system failing to be in a satisfactory operating state on days of expected high demand.[14] As a result, even in the

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[11] See NER 4.1.1(b).

[12] The '*power system security and reliability standards'* are defined in the glossary as being standards approved by the Reliability Panel on the advice of NEMMCO. We understand from discussions with the Reliability Panel that none of the standards currently in place contain additional guidance on returning the power system to a satisfactory operating state.

[13] Under NER 4.2.6(a), following a contingency event NEMMCO must take all reasonable actions to ensure that the system returns to a *secure* operating state as soon as possible, and, in any event, within thirty minutes.

[14] Where high demand is defined as being above the 10% POE level, as set out in section 4.

absence of a credible contingency, the system will not be in a *secure* operating state from that date, since to be in a secure operating state the system must be able to continue to be in a satisfactory operating state following a credible contingency. Under clause 4.2.6(a), NEMMCO would therefore be required to shed load on days when demand was expected to be high, in order to maintain the system in a secure operating state.[15] Such load shedding would occur as a pre-emptive measure, in the absence of the single credible contingency event actually having occurred, since (under 4.2.4(a)) the system needs to be able to return to a satisfactory operating state following a single credible contingency.[16]

As a result, NEMMCO's system security obligations mean that there could be load shedding in the Newcastle-Sydney-Wollongong region in the relatively near future, even with all of the transmission system elements in place.

As noted above, there is an obligation on TransGrid under Schedule 5.1.2.1 to plan, design and operate its network to allow the transfer of (all reasonably forecast) power with all facilities or equipment in service. Unless it takes action, TransGrid will no longer meet this obligation in the near future, as a consequence of the interaction of network planning with NEMMCO's power system security obligations.

The implication of the above is that in this case TransGrid needs to determine the limitations of its network by considering the implications of an outage of a critical element. This approach is equivalent to that used when providing for an (n-1) reliability standard, although the underlying requirement is different. This is consistent with the approach taken in TransGrid's Network Asset Management Plan. It also meets jurisdictional expectations, as described in TransGrid's Electricity Network Performance Report:

> 'In addition to meeting requirements imposed by the [NER], environmental legislation and other statutory instruments, TransGrid is expected by the NSW jurisdiction to plan and develop its transmission network on an "n-1" basis. That is, unless specifically agreed otherwise by TransGrid and the affected distribution network owner or major directly connected end-use customer, there will be no inadvertent loss of load (other than load which is interruptible or dispatchable) following an outage of a single circuit (a line or a cable) or transformer, during periods of forecast high load.'[17]

In addition, the NSW distributors are required as a Ministerially imposed condition of their licences to plan their networks so that all supply points with load above a certain level can continue to be supplied (after one minute at most) following a critical contingency on their

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[15] We have confirmed in discussions with NEMMCO that clause 4.2.6(a) would require them to pre-emptively shed load, before a single credible contingency occurred, where the occurrence of a single credible contingency event would result in the system no longer being in a satisfactory operating state. Indeed, NEMMCO has previously pre-emptively shed load in the NEM for this reason. The exception would be where NEMMCO was able to enter into contingency arrangements which could be triggered after the occurrence of a credible contingency event in order to return the system to a satisfactory operating state. The technical feasibility of entering into such contingency arrangements will depend on the precise nature of the contingency event.

[16] The provisions in relation to power system security in the NER recognise that the consequences of the power system failing to be in a satisfactory operating state following the actual occurrence of a credible contingency event would be greater than consequences of targeted load-shedding in anticipation of a credible contingency event.

[17] TransGrid, *2004-2005 Electricity Network Performance Report*, Doc. No. D2005/10700, October 2005, p.8.

network.[18] Consequently, the distributors expect TransGrid to incorporate"n-1" reliability levels into its own planning standards and processes so that the single contingency reliability requirement specified in their distribution licences can be delivered.

The planning approach used by TransGrid in relation to the forecast network limitations described above is consistent with the licence requirement on the NSW distributors.

In summary, it is expected that the current network will cease to meet minimum network performance requirements in the relatively near future; possibly by the summer of 2008/09.

[18] This licence condition is imposed as a result of a directive by the NSW Department of Energy, Utilities and Sustainability (DEUS). We understand that the relevant load limits are 15MVA for rural areas and 5MVA for most urban areas, applied to sub-transmission lines and zone substations.

4. Market Development Scenarios

This section discusses the market development scenarios NERA has adopted in applying the regulatory test to the 500kV upgrade.

4.1. The Role of Scenarios in the Regulatory Test

Under the 'reliability limb' of the regulatory test, an option satisfies the regulatory test if:

> '[...] the option minimises the present value of *costs*, compared with a number of *alternative options* in a majority of reasonable *scenarios.*' (regulatory test (1)(a))

'Reasonable scenarios' are defined under item (4) of the regulatory test as meaning scenarios incorporating:

a) 'reasonable forecasts of:
   - Electricity demand [..]
   - [..][19]

b) Scenarios defined as market development scenarios; and

c) Sensitivity testing'.

The rationale for assessing the costs of alternative options across a number of reasonable scenarios is to test the robustness of the results. In particular, where the assessment relies on forecasts or on key assumptions in relation to uncertain variables, the outcome should be tested against variations in these forecasts or assumptions.[20]

In addition, the assumed future pattern of investments in the NEM (both generation and transmission) has the potential to affect both the required timing of an option and the precise nature and costs associated with that option. A particular option may also itself have an impact on future NEM development. Given that the future development of the NEM is uncertain, the requirement for reasonable scenarios to also cover alternative 'market development scenarios' is intended to test the robustness of the regulatory test assessment to differences in assumed NEM development patterns.

Under the reliability limb, the regulatory test analysis is limited to the direct costs associated with each option and does not include avoided costs.[21] As a result, market development scenarios are relevant under the reliability limb of the regulatory test only where they impact the *timing* of the option required to meet the minimum network performance requirements, or the precise *nature* and *direct costs* of that option. Market development scenarios are not

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[19] The other factors listed under regulatory test item 4(a)(ii)-(v) are not relevant to the assessment of options under the reliability limb, since they relate to the forecasts of avoided costs, and so these factors have been omitted here for brevity.

[20] Variations in key assumptions are captured by the requirement for reasonable scenarios to encompass sensitivity testing ((4)(c)). Sensitivity testing is discussed in detail in section 6.

[21] See discussion in section 2.2.

relevant in terms of the impact of the option on the wider market (eg, deferral of generation investment elsewhere in the NEM), since benefits associated with avoided costs are no longer taken into account under the revised reliability limb of the regulatory test.

As a result, the role of market development scenarios is considerably more limited than it is under the 'market benefit' limb of the regulatory test.

4.2. Summary of Scenarios

The market development scenarios considered in this analysis therefore focus on:

- Different demand scenarios, which impact the time at which the existing network is no longer expected to meet minimum network performance requirements; and
- Different patterns of generation investment that may occur in the NEM insofar as these impact the time at which the existing network is no longer expected to meet minimum network performance requirements.

We have considered nine market development scenarios as part of our regulatory test assessment. These are summarised in Table 4.1 below, and explained in further detail in the remainder of this section.

Table 4.1: Summary of Scenarios

Shows Date at which the Network is Not Expected to Meet Minimum Network Performance Standards under each Scenario

		GENERATION DEVELOPMENT SCENARIOS		
		EARLIER	**CENTRAL**	**LATER**
Demand Forecasts	**High**	**Scenario H1:** 2007/08 [22]	**Scenario H2:** 2008/09	**Scenario H3**: 2009/10
	Medium	**Scenario M1:** 2008/09	**Scenario M2:** 2009/10	**Scenario M3:** 2010/11
	Low	**Scenario L1:** 2009/10	**Scenario L2:** 2010/11	**Scenario L3:** 2011/12

The nine market development scenarios set out in the table above have been constructed by combining alternative potential demand forecasts (high, medium and low load growth) with alternative potential patterns of new generation investment. These different scenarios impact

[22] This scenario is not considered realistic: see discussion in Section 5.2.

the time at which the existing network is expected to no longer meet minimum network performance requirements (as shown in the table).

The various generation investment scenarios have been grouped into three categories, based on one criterion: whether the pattern of generation investment brings forward (this scenario is labelled 'earlier') or pushes back ('later') the date that the system is expected to become unable to meet minimum network performance requirements, compared with our central scenario.[23] We have focused on this aspect because it summarises the impact of the pattern of generation investment on the required timing of the options being considered; this is the sole relevance of the generation scenarios under the reliability limb of the regulatory test.[24]

4.3. Demand Scenarios

Under item 4(a)(i) of the regulatory test, the analysis needs to consider reasonable forecasts of electricity demand (modified where appropriate to take into account demand-side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity).

We have considered the following three load growth scenarios:

- Medium demand (Scenarios M1 – M3 in Table 4.1)
- Low demand (Scenarios L1 – L3)
- High demand (Scenarios H1 – H3).

In all cases the demand forecasts are based on summer maximum demand (MW) at 10% POE, as set out in NEMMCO's 2005 Statement of Opportunities (SOO) and reproduced in Table 4.2. The forecasts take into account expected economic growth and the impact of existing and forecast future demand management initiatives.

Table 4.2: NSW Summer Maximum Demand Projections (MW), 10% POE

	Low	Medium	High
2005/6	14,030	14,080	14,140
2006/7	14,360	14,420	14,480
2007/8	14,780	14,900	14,980
2008/9	15,110	15,310	15,440
2009/10	15,440	15,750	15,990
2010/11	15,800	16,250	16,640
2011/12	16,100	16,700	17,720
2012/13	16,370	17,110	17,840
2013/14	16,680	17,560	18,470
2014/15	17,060	18,130	19,200

[23] Note that the central scenario has not been attached any greater weight in the regulatory test analysis, and that the terminology has been adopted for ease of exposition only.

[24] Differences in the expected pattern of NEM generation investment do not impact the cost or nature of the options themselves.

The different demand scenarios (taken together with the assumed pattern of future generation investment) affect the time at which the current network is expected to no longer meet minimum network performance requirements. This is reflected in the regulatory test analysis. The different demand scenarios do not affect the nature (or cost) of the network option which needs to be built or the non-network option components.

4.4. Generation Development Scenarios

We have considered the future pattern of NEM generation development, insofar as it is expected to impact the direct cost and/or timing and nature of the options considered. Generation developments differ in their impact on the timing of the inability of the network to meet minimum network performance requirements, depending on the capacity of the generation and its location, and also on whether there are other generators in the vicinity.

4.4.1. Generation developments identified in the 2005 SOO Update

As discussed in section 4.2 above, we have grouped potential future patterns of generation investment into three groups, depending on the impact of each pattern of generation on the timing of the need for TransGrid to implement an option (whether network or non-network).

Before we discuss these groupings of generation development, it is useful to summarise the potential generation investments which NEMMCO has identified in the most recently available Statement of Opportunities Update January 2006 (SOO Update).[25] Our various generation development scenarios reflect combinations of the potential investments identified in the SOO Update.

There are no currently committed generation projects in NSW included in the SOO Update.

The SOO Update identifies a number of 'proposed scheduled generation projects', and indicates which of the criteria listed in item 12 of the regulatory test have been met (or are in the process of being met) for each. All of the projects included in the SOO Update fall within the regulatory test definition of 'anticipated projects'. However, NEMMCO makes a distinction between 'advanced proposals' and 'publicly announced proposals', where the former have satisfied a greater number of the listed criteria.

NEMMCO has classified the following as 'advanced proposals' in NSW:[26]

- TRUEnergy: 400MW CCGT at Tallawarra, with a commissioning date of early 2008. This project has all of the five criteria above either already in place or in progress.
- Wambo Power Ventures: 600MW OCGT at Wagga Wagga, with a commissioning date of summer 2007/8. This project has four of the five criteria above either already in place or in progress.

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[25] NEMMCO, *2005 Statement of Opportunities Update*, January 2006

[26] NEMMCO, *2005 SOO Update*, p. 4.

NEMMCO has changed the category of the TRUEnergy Tallawarra proposal from 'publicly announced' (in the previous SOO) to 'advanced proposal' in the 2005 SOO.[27] The NSW Premier also recently announced that the proposal was expected to proceed. [28]

The 2005 SOO Update also identifies a number of what NEMMCO classifies as 'publicly announced' generation proposals:

- Delta Electricity: 600MW OCGT at Munmorah, with estimated commissioning dates of 2009 (for units 1 and 2, 300MW) and 2010 (for units 3 and 4, the remaining 300MW);[29]
- Delta Electricity: 400MW CCGT at Nowra, with an estimated commissioning date of 2010.[30]
- Delta Electricity: 400MW CCGT at Marulan 2010/11;
- Macquarie Generation: 500MW OCGT at Tomago (no commissioning date given);
- Delta Electricity: Mt Piper Upgrade (no commissioning date given) - based on upgrades of other similar units, TransGrid expects this to be less than 100 MW;
- Wambo Power Ventures: 114MW CCGT at Cobar 2008/9; and
- Wambo Power Ventures: 120MW CCGT at Bega 2008/9.

In the majority of cases, these proposals also meet the regulatory test criteria for inclusion as 'anticipated' projects, since they satisfy at least one of the criteria listed in item 12 of the regulatory test. However, these proposals have completed (or have in progress) fewer of the criteria, and therefore their development is less certain than the 'advanced proposals'.

NEMMCO notes that there is expected to be a shortfall of generation capacity in NSW of around 370MW in 2008/9.[31] In the event that the proposed Tallawarra investment does not proceed in 2008/9, it is therefore likely that a new peaking generator would nevertheless enter the market by 2008/9, as a result of spot prices moving high enough to make a generator commercially viable by that date. The most likely outcome is that one of the other proposed investments listed above would be brought forward. Indeed, the NSW Premier's office has indicated that if TRUEnergy does not proceed with its Tallawarra investment "in a timely manner", then both stages of Delta Electricity's proposed development at Munmorah could be brought forward.[32] Alternatively, a completely new generation project may be developed

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27 NEMMCO, *2005 SOO Update*, p. 4.

28 The Honourable Morris Iemma MP, *Economic and Financial Statement*, 23 February 2006, p. 19. The commissioning date reported is late 2008 (rather than early 2008 as per the 2005 SOO Update).

29 Delta's proposed 600MW power station at Munmorah was also recently announced as 'proceeding' by the NSW Premier . The Honourable Morris Iemma MP, *Economic and Financial Statement*, 23 February 2006, p. 19.

30 The 2005 SOO Update notes that this commissioning date is dependent on demand growth.

31 The SOO estimates the reserve deficit in NSW to be 372MW in 2008/9. This assessment does not take into account any of the proposed generation projects listed in the SOO. NEMMCO, *SOO Executive Briefing*, October 2005, p.5.

32 Premier of NSW, News Release, 7 December 2005, *Two New Power Stations for NSW*

by that date (ie, a 'modelled project', in terms of the regulatory test terminology) to ensure that the supply/demand balance in NSW is met in that year.[33]

In the following section we consider the impact of each of the above generation investment proposals on the timing of the identified inability to meet minimum network performance requirements, and therefore the timing of the options considered under the regulatory test.

4.4.2. Impact of generation developments on timing of options considered under the regulatory test

Generation developments differ in their impact on the timing of the inability of the network to meet minimum network performance requirements, depending on their capacity and location, and also on whether there are other generators in the vicinity.

The network is nearing the limit of its ability to reliably supply the Newcastle - Sydney - Wollongong area. TransGrid has advised that while new generation developments in parts of NSW outside this area, such as Wagga Wagga, Bega, Mt Piper and Marulan,[34] can assist in meeting the general need for additional supply in NSW, they do not address the network constraints in the Newcastle - Sydney - Wollongong area (without network upgrades).

TransGrid's modelling indicates that additional generation capacity ***within*** the Newcastle - Sydney - Wollongong area of around 350MW would be needed each year from 2008-09 to address the identified network limitations, and to delay the need for network augmentation or other (non-network) action by TransGrid.[35] Even ***within*** the Newcastle - Sydney - Wollongong area, however, the effectiveness of generation will vary depending on its exact location.

We consider it reasonable to assume that, once a generator is built, it would then be operating at the expected time of system constraint, ie, at peak times. A tight supply-demand balance is expected in the NSW region of the NEM over the next few years,[36] which will result in a strong price incentive for generators to operate at peak times.[37]

The following generation developments are proposed for within the Newcastle - Sydney - Wollongong area:

- TRUEnergy 400MW OCGT at Tallawarra;

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[33] It is reasonable to assume that a new peaking generator will enter in 2008/9, either as a result of spot prices in NSW reaching levels high enough to make such a generator commercially viable (given the expected supply deficit), or under NEMMCO's Reserve Trader powers.

[34] A generator at Marulan would need to be combined with substantial network augmentation in order to address the minimum network performance requirements.

[35] Approximately 350 MW would be needed for summer 2008/09, 700 MW for summer 2009/10 and 1,100 MW for summer 2010/11.

[36] As set out in NEMMCO's 2005 SOO.

[37] The regional reference node for NSW is located in the Sydney area, at Sydney West. Therefore whenever the network becomes constrained at one of the points we are considering (eg, between Newcastle and Sydney) then the price at the regional reference node will be high, so the NSW spot price will be high.

- One of Delta's proposed 300 MW OCGT developments at Munmorah;[38]
- Macquarie Generation's proposed 500 MW OCGT at Tomago;[39] and
- Delta's proposed 400 MW CCGT at Nowra.

Under the medium demand scenario, TransGrid advises that if two or more of these generators in combination were to proceed,[40] it would postpone the need for TransGrid to take action by a year until 2009/10.[41] If only one of these generators were to proceed, the need for TransGrid to take action would not be postponed, because none of the generators is proposed for the most effective location (the Sydney basin).

Combinations of such generators may therefore delay the need for TransGrid to take action for a year or more. However, where excessive generation capacity becomes located in the same area of the network, this imposes a constraint on the extent of such a delay in action. For example, TransGrid has advised that due to the short circuit rating limitations of switchyards in the Hunter Valley, new gas turbine generators would be able to be connected at Tomago or Munmorah only to a limit of about 300 MW. Additional installed generation capacity above this limit at these points would not be able to be online without network augmentation to overcome fault level constraints.

In the following section we discuss the grouping of the above generation investments into the three generation scenarios we have considered in our analysis.

4.4.3. Three generation development scenarios

As discussed in section 4.2 and set out in Table 4.1, we have defined three broad generation development scenarios, based on whether the pattern of generation investment brings forward or pushes back the date that the system is expected to become unable to meet minimum network performance requirements, compared to a central generation development scenario.

4.4.3.1. Central generation scenario[42]

Considering the medium demand scenario, in the absence of any further generation development in NSW TransGrid would need to take action by 2008/9 in order to ensure that the network continues to meet minimum network performance requirements.

Any pattern of generation investment which resulted in sufficient additional generation capacity in the Newcastle - Sydney - Wollongong area in 2008/9 to meet the identified 350MW requirement, without exceeding the short circuit rating limitations discussed above,

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[38] See discussion of short circuit rating limitations below.

[39] Without a network upgrade, there is an effective limit of 300 MW of additional generation plant online in the Central Coast/Newcastle area, due to the short circuit rating limitations of switchyards in the Hunter Valley. See discussion of short circuit rating limitations below.

[40] As discussed above, it appears likely that at least one of these generation developments will occur by 2009; it is less likely that two will occur, but this possibility cannot be ruled out.

[41] Provided the combination did not cause short circuit rating limitations of switchyards in the Hunter Valley to be exceeded. See discussion of short circuit rating limitations below.

[42] We have named this scenario 'central' for convenience of exposition only.

would push back the date that the system is expected to become unable to meet minimum network performance requirements to 2009/10. TransGrid has advised that a combination of two out of the four generation proposals listed in section 4.4.2 would assist in achieving this, provided the combination did not cause short circuit rating limitations of switchyards in the Hunter Valley to be exceeded.

Under the central generation development scenario, therefore, we assume that generation developments of sufficient capacity occur within the Newcastle - Sydney - Wollongong area in 2008/09; and another generator locates either outside of the constrained area in 2009/10 or within the same area but in a location that *does* exceed short circuit rating limitations.

When combined with various demand scenarios and transmission developments, the central generation scenario produces the following market development scenarios (which are set out in Table 4.1): M2, L2, and H2.

4.4.3.2. Early generation scenario

We have also defined an 'early' generation development scenario, where TransGrid needs to take action in 2008/09 under medium forecast demand levels.

In the early scenario, in 2008/09:

- *either* insufficient generation development occurs within the Newcastle - Sydney - Wollongong area to meet minimum network performance requirements; *or*
- generation developments of sufficient capacity occur within the Newcastle - Sydney - Wollongong area, but cause short circuit rating limitations to be exceeded.

An example of the early scenario is that in 2008/09, generation development occurs at Munmorah to the full 600 MW capacity or at Tomago to 500MW capacity (and no other generation developments occur in NSW). Under these scenarios, dispatch of either of these generators above 300MW would risk exceeding the short circuit rating limitations discussed above, and would thus require an upgrade of the network.

The early generation scenario is reflected in Scenarios M1, L1 and H1.

4.4.3.3. Late generation scenario

The third possibility is that generation which eases the constraint occurs in 2008/09 and 2009/10.

In this 'later' scenario, TransGrid needs to take action in 2010/11. This date is likely in most circumstances to be the latest date to which TransGrid could defer the need to take action. TransGrid's modelling indicates that most of the likely generation development patterns would require action to meet minimum network performance requirements by 2010/11, even where all new generation investment is located in areas which ease the anticipated constraint.

An example of the later scenario is that one 300 MW generation development occurs at Munmorah and a 400 MW generator locates at Nowra in 2008/09; and a 400 MW generator locates at Tallawarra in 2009/10.

The late generation scenario is reflected in Scenarios M3, L3 and H3.

4.4.4. Interaction between generation and demand scenarios

The above discussion of the impact on option timings of the generation scenarios is based on the medium load growth scenario.

TransGrid has advised that the low load growth scenario can be assumed to provide a 1 year deferral of all generation developments in the NEM, relative to the medium growth scenario. The high load growth scenario results in a 1 year advancement of all generation developments.

It follows that the two demand scenarios impact in a similar way on the date that the system is expected to become unable to meet minimum network performance requirements and action by TransGrid is required. That is, the high demand scenario brings that date forward by one year, and the low demand scenario pushes it back by one year, for each of the three assumed generation patterns, when compared to the medium demand forecast. The resulting impacts on option dates are shown in Table 4.1 in section 4.2.

4.5. Transmission Developments

Future transmission developments in the NEM are relevant for the regulatory test analysis under the reliability limb only where they are expected to impact the nature, timing or cost of the options being assessed.

We note that any of the options currently proposed to address the identified inability to meet minimum network performance requirements would not be expected to result in these standards continuing to be met for the entire ten year period of the analysis.

TransGrid currently expects that there will be a need to build a new 500kV transmission line sometime within the next ten years, in order to support the development of the next baseload generator in NSW and to ensure that minimum network performance requirements in the Newcastle-Sydney-Wollongong area continue to be met once this generator is operational. At this stage there are two broadly defined alternatives for this development:

- a new 500kV transmission line into the Newcastle / Central Coast area from the Hunter Valley ('Bayswater – Eraring'[43]); and
- a new 500kV transmission line into Sydney from Bannaby ('Bannaby - Kemps Creek'[44]).

The timing of the expected future augmentation, and whether the required augmentation is a transmission line between the Hunter Valley and Newcastle, or between Bannaby and Sydney, will depend on the timing and location of the next baseload generator in NSW. If a

[43] The Bayswater - Eraring development could comprise a double circuit 500kV line, two 500kV switchbays at each of Bayswater and Eraring, a new 500/330 kV substation at Richmond Vale (west of Newcastle), short sections of 330 kV line from Richmond Vale to the existing Newcastle 330 kV network and a third 500/330 kV transformer at Kemps Creek (in Sydney).

[44] The Bannaby - Kemps Creek development could comprise the double circuit 500kV line, two 500kV switchbays at each of Bannaby and Kemps Creek and a third 500/330 kV transformer at Kemps Creek.

baseload generator is located in the north of the State, then the required augmentation would be Bayswater-Eraring. If, however, the baseload generator is located in the south of the State, then the required augmentation would be Bannaby-Kemps Creek. Currently the location of the next baseload generator in NSW is highly uncertain.[45]

Importantly, the option which is undertaken in order to address the currently identified inability to meet minimum network performance requirements in the near term will have no impact on either the timing or the nature of the later required transmission augmentation. The timing of the later development and its cost will therefore be the same, whichever of the options being considered in this regulatory test assessment goes ahead. As such, the future transmission augmentation has a common impact on all options.[46]

The cost of the additional network development has not been included as part of the cost of the options being assessed under this application of the regulatory test. The future developments are considered to be part of the background market development scenario, rather than part of the options being assessed.[47] The later transmission augmentation will be assessed by TransGrid in accordance with the regulatory test, once it is anticipated with greater certainty.

In relation to other anticipated transmission developments, we understand that any change to the capacity of QNI or the addition of a further Queensland-NSW interconnector would not affect the expected inability to meet minimum network performance requirements, and so would not impact the costs or timing of the options. As a result we have not had to make any assumptions regarding the likely timing of such an upgrade in conducting the regulatory test analysis.

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[45] No such generation projects have been included as proposed generation developments in the 2005 SOO Update.

[46] This impact is considered in section 7.

[47] This approach has been discussed and confirmed with the AER.

5. Identifying Alternative Options

This section outlines alternative options for addressing the anticipated inability to meet minimum network performance requirements in the Newcastle - Sydney - Wollongong area.

Under the NER, TransGrid is required to assess a range of options to address the inability to meet anticipated network limitations. These options include, but need not be limited to, DSM options, generation options and market network service provider options, in addition to (regulated) network augmentation options. Further, combination options may be defined, which incorporate network and non-network developments as components of one overall option. For example, an option may comprise a network augmentation combined with a DSM program.

Table 5.1 summarises the options considered in this initial regulatory test analysis.

Table 5.1: Summary of Options

Option 1	08/09: network support (generation and/or DSM) 09/10: 500kV upgrade
Option 2	08/09: network support (generation and/or DSM) 09/10: network support (generation and/or DSM) 10/11: 500kV upgrade

The options considered at this draft stage both comprise a combination of a network augmentation and a non-network measure, that is, a generation network support contract or DSM or both. Generator network support contracts and DSM, either alone or combined, are not expected to be sufficient to address the inability to meet minimum network performance requirements. However, network augmentation will take several years to complete and network support contracts or DSM programs are likely to be required in the interim. Non-network programs may also defer the need for augmentation.

It should be stressed that at this stage the non-network component of the options is indicative only. It is anticipated that the final regulatory test analysis will consider specific options which include DSM and/or generation network support components, together with network augmentation. Discussions with potential proponents of such options are expected to be on-going following the release of TransGrid's Application Notice.

5.1. Option Components

5.1.1. Network

5.1.1.1. 500kV Upgrade

TransGrid has developed a proposed network augmentation in response to the emerging inability to meet minimum network performance requirements, which involves conversion of the existing transmission lines from Bayswater to Mt Piper and Mt Piper to Bannaby from 330kV to 500kV operation. This is referred to throughout this paper as the '500kV upgrade'.

The 500kV upgrade consists of the following main works:

- construction of a new 500 kV switchyard at Bayswater and transfer of the connection of two generating units (3&4) to the 500 kV switchyard;
- conversion of the 500 kV switchyard at Wollar from operation at 330kV to operation at 500kV;
- construction of a new 500 kV switchyard at Mt Piper;
- development of a 500 / 330 kV substation at Bannaby;
- uprating of the lines and terminal equipment for the Marulan – Dapto No. 8 330 kV line and Marulan – Avon No. 16 330 kV line;
- 500/330 kV transformers at each site; and
- uprating of 330 kV switchgear in the Wallerawang 330 kV switchyard.

The 500kV upgrade is depicted in Figure 5.1 over the page. Figure 5.1A depicts the NSW transmission network in its current state, with the transmission lines between Bayswater and Marulan operating at 330kV. Figure 5.1B depicts the network after the upgrade, including:

- the upgraded Bayswater, Wollar and Mt Piper 330kV / 500kV sub-stations;
- the new 330kV / 500kV Bannaby sub-station;
- the lines between Bayswater and Bannaby operating at 500kV; and
- the uprated 330kV lines between Marulan and Dapto/Avon.

Figure 5.1: The 500kV upgrade

Figure 5.1A: NSW network currently

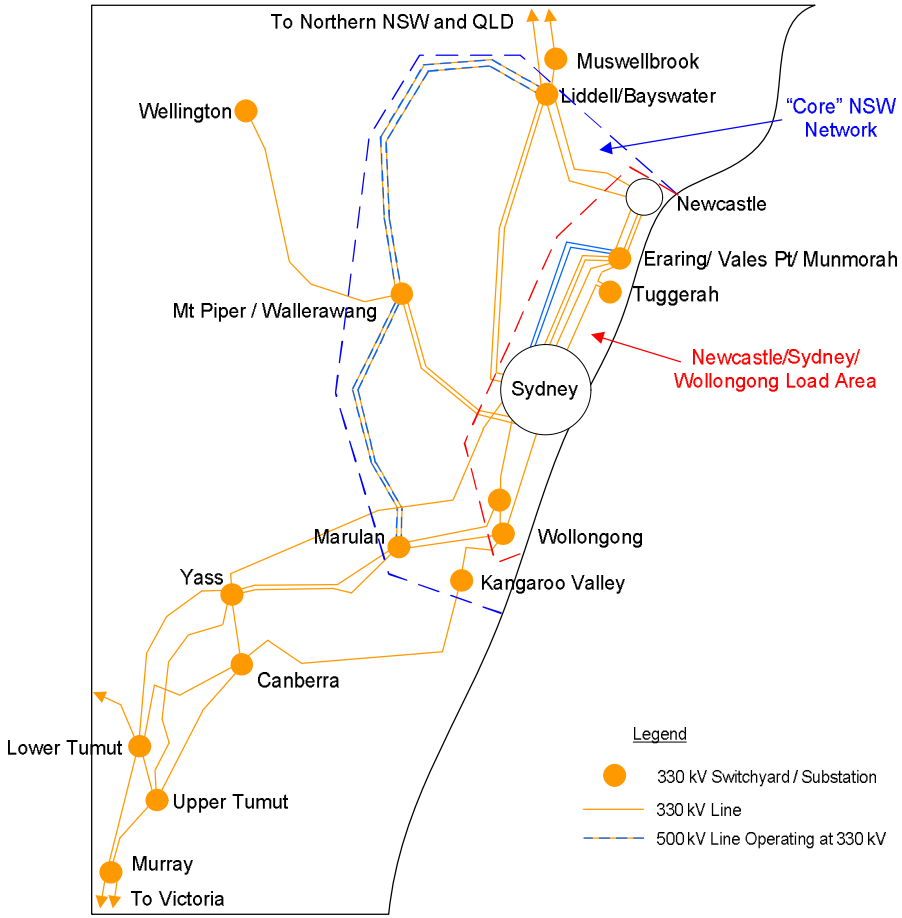
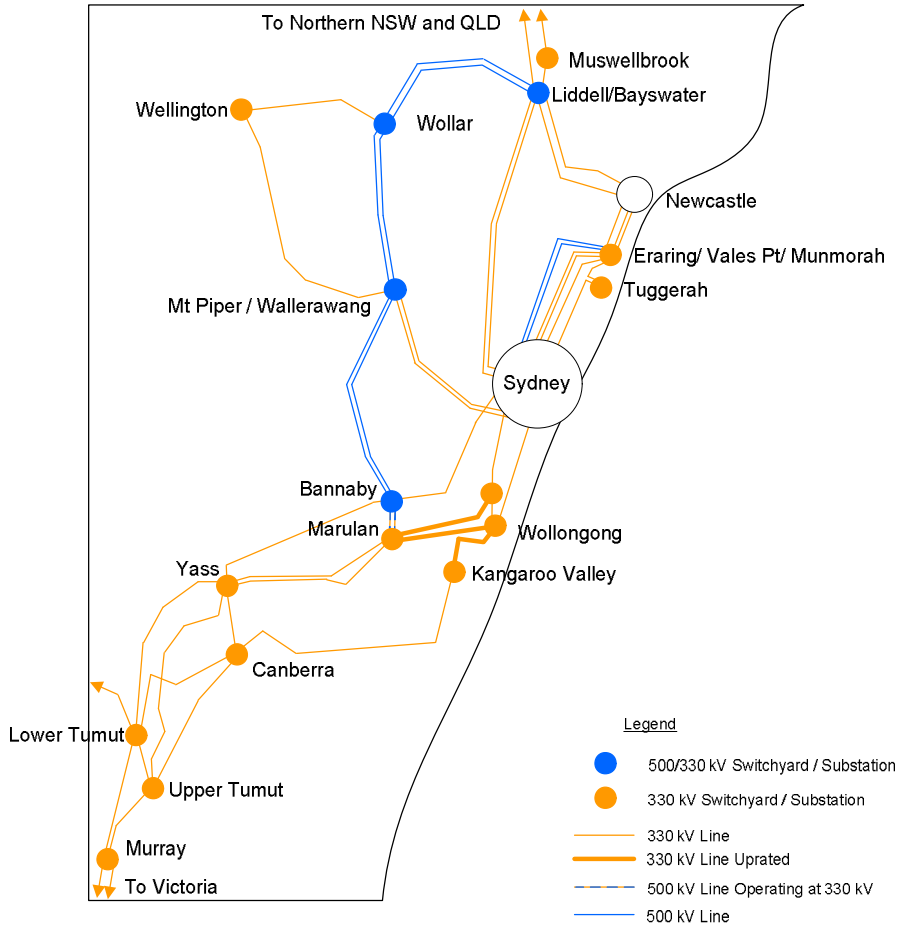


Figure 5.1B: NSW network after 500kV upgrade



The 500kV upgrade does not enable TransGrid to provide any non-prescribed services.

As discussed in TransGrid's Application Notice, it is currently expected that the majority of the construction for the proposed 500kV network upgrade could be completed before summer 2009/10. However it is unlikely that the final stage could be completed until April 2010. This final stage consists of transferring the final generation unit at the Bayswater substation (Unit 3) from the existing 330kV system to the new 500kV system. Before this final stage is complete, the 500kV upgrade will be partially effective (approximately 75% of the final reliability improvement to the Newcastle - Sydney - Wollongong area). If construction proceeded on the timescale under discussion, it is expected that the upgrade would be sufficient to meet maximum forecast demand levels as set out in the 2005 SOO by summer 09/10.

5.1.1.2. 500kV Upgrade Excluding Units 3 and 4

TransGrid has identified an alternative potential network option, a variation on the 500kV upgrade, which differs from the primary network option in that it excludes transferring the generator transformers at Bayswater Units 3 and 4. This option ("500kV upgrade excluding Bayswater Units 3 and 4"), which could be completed by summer 2009/10, would be effective to some extent in meeting demand in the Newcastle - Sydney - Wollongong area, as it would provide roughly half the additional reliability improvement of the full 500kV upgrade.

However, this alternative network option will not be effective in all circumstances. If excessive generation capacity were to be located in the Hunter Valley / Central Coast area, short circuit rating limitations would be exceeded at a number of 330kV substations. In such a scenario the full 500kV upgrade would overcome this problem and thereby enable minimum network performance requirements to be met; however, the 500kV upgrade excluding Bayswater Units 3 and 4 would not. Thus the extent to which the latter option would be effective will depend on the pattern of generation development, particularly in the Hunter Valley / Central Coast area.

5.1.1.3. Additional Network Options

TransGrid is also investigating other alternative network augmentations (including an option involving the uprating of lines in the south of NSW), which could also meet the expected future constraints in the network, or at least provide some deferral of other options.

These augmentations are either not practicable, or do not fully address the minimum network performance requirements. Consequently, no other network augmentations have been included at this draft stage of the regulatory test application. One or more other alternative network augmentations may however be included in the final regulatory test analysis.

5.1.2. Non-network alternatives

Under the NER, TNSPs are required to consider non-network alternatives to augmenting the network, including both generation and DSM. At this stage, no firm proponents have come forward for either generation or DSM options to address the anticipated inability to meet minimum network performance requirements. However, as discussed above in section 2.2, given the interest expressed to date and the potential for proponents of non-network options

to emerge prior to TransGrid's final regulatory test decision, we believe it is appropriate to consider non-network options in this initial regulatory test application on an indicative basis, despite the lack of a firm proponent at this stage.

5.1.2.1. Generation

If located in appropriate areas, generation support could allow minimum network standards to continue to be met and could further defer the need for network augmentation. Network support from a generator could be obtained via a contract between a TNSP and a generator. Cogeneration at major industrial facilities could provide an alternative form of generation network support.

TransGrid highlighted the emerging inability to meet minimum network performance requirements in its September 2005 Needs Statement.[48] In response to the Needs Statement, TransGrid has received indications of interest from potential proponents of three generation investment proposals, namely:

- TRUEnergy's proposed 400MW OCGT at Tallawarra;
- Delta Electricity's proposed two 300 MW OCGT investments at Munmorah; and
- Delta Electricity's proposed 400MW CCGT at Nowra.

As discussed in Section 4.4, generation developments which result in additional generation capacity within the Newcastle - Sydney - Wollongong area in 2008/9, without exceeding short circuit rating limitations, may assist in pushing back the date that the system is expected to become unable to meet minimum network performance requirements.

As discussed in that section, although there are several proposed generation investments included in the SOO Update which may potentially be built by 2008/9, none of these plants are currently committed, and so TransGrid necessarily faces some uncertainty as to whether there will be additional generation located in the constrained area in 2008/9 to allow minimum network standards to be met in that year without TransGrid needing to take action. Entering into a network support contract with a generator would be one means of removing that uncertainty.

Entering into a network support agreement with either TRUEnergy for its Tallawarra development or Delta Electricity for its Nowra development or its initial 300MW Munmorah development would assist in allowing minimum network performance requirements to continue to be met until at least 2009/10.[49] Although the capacity of the proposed generators at Tallawarra and Nowra exceeds 350MW, neither of these generators would be likely to meet the required capacity on its own, because it would not be in the most effective location for meeting this requirement (ie, the Sydney basin). Consequently, the generation development under consideration is likely to need to be complemented with DSM (the required quantity of which would depend on the location of the generator).

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[48] TransGrid, Sept 2005, *Emerging Major Transmission Network Limitations in Supplying the Newcastle-Sydney-Wollongong Load Area, Needs Statement*

[49] To be fully effective the Nowra development would also require TransGrid to carry out some line uprating, the cost of which would form part of the costs of any option incorporating the Nowra generator.

5.1.2.2. DSM

DSM programs could allow minimum network standards to be met and could further defer the need for network augmentation by reducing peak demand levels in the areas which are expected to become constrained. DSM potentially encompasses various initiatives, including firm and non-firm load reduction agreements with large industrial electricity users and also with medium and small customers.

DSM programs could also include two types of small generators:

- standby generators within customer facilities (which are generally small, always below 5MW and usually 1MW or less); and
- smaller embedded generation (which exist to sell power).

We distinguish these small generation activities from the CCGT and OCGT investments considered in the previous section, since, given their relatively small capacities, they would need to be considered as part of a larger package. Accordingly, it is convenient to treat them as part of the non-network solution range considered under the DSM heading.

For an option incorporating DSM measures to proceed, TransGrid would need to either contract with end-users directly, or enter into a network support contract with a third-party provider or 'aggregator'. A DSM aggregator could contract with TransGrid to provide an agreed level of demand-side reduction from peak demand levels, through its own agreements with various electricity users.

TransGrid has advised that a demand reduction in the Newcastle - Sydney - Wollongong area of approximately 350MW (depending on location) by 2008/9 would push back the date that the system is expected to become unable to meet minimum network performance requirements by a year, until at least 2009/10.

TransGrid issued an RFP for non-network options in March 2006.[50] It has appointed a consultant (CRA) to consider the potential for DSM and embedded generation options and manage the RFP process. CRA have advised that contact has been made with the following types of potential providers of non-network solutions:[51]

- all electricity distribution companies whose service territories overlap the project area;
- electricity retailers with a significant number of large customers in the project area;
- demand response aggregators;
- companies that build own and operate embedded generation; and
- a select number of large end-use customers.

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[50] TransGrid, March 2006, *Request for Proposal, Provision of Non-Network Alternatives for the Newcastle-Sydney-Wollongong Load Area*

[51] CRA International, May 2006, Preliminary Status Report: *Assessment of Non-Network Solutions for the 500 kV Project*

CRA have advised that there is significant interest on the part of potential providers of non-network solutions, that achieving 350MW of load reduction or generation injection is possible, and that it also appears possible that significant further reduction (again in areas that would address the constraint) could be obtained in a subsequent year. Discussions with proponents remain on-going.

Further details regarding the technical requirements for DSM options are available as an appendix to TransGrid's draft application notice.

5.1.2.3. Combinations of non-network alternatives

As discussed in the previous sections, there are two broad categories of non-network alternatives capable of postponing the date that the system is expected to become unable to meet minimum network performance requirements:

- generation; and
- DSM.

In both cases, the required capacity is around 350MW (depending on location).[52]

An additional possibility is that TransGrid could implement a combination of these non-network alternatives. For example, it could contract for the provision of 300MW in network support from a generator, and enter a separate contract for around 50MW of DSM. Such a combination may be sufficient to push back the date that the system is expected to become unable to meet minimum network performance requirements to at least 2009/10.

5.1.2.4. A generic non-network alternative

On the basis of the progress noted above, it is expected that a firm proponent will emerge for one or more non-network alternatives by the final stage of the regulatory test application. Consequently, in the final regulatory test analysis we intend to cost specific non-network components of options on the basis of the price proposed in the contract with the proponent(s).[53] The final analysis may include options that have generation non-network components, options that have DSM components, and options that have both generation and DSM (if potential proponents emerge for both generation and DSM).

At this stage, there is no firm information on which to base an assessment of specific generation or DSM options. We consider that it is appropriate to consider a generic non-network alternative, and to estimate the costs for such an option on the basis of underlying capital costs. This is partly because robust cost information for either a specific generation option or a DSM option is not yet available. It is also because commercial negotiations between TransGrid and potential proponents of non-network alternatives are expected to be on-going following the release of TransGrid's Application Notice, and the use of specific cost

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[52] Although the capacity of the proposed generators at Tallawarra and Nowra exceeds 350MW, neither of these generators would be likely to meet the required capacity on its own, because it would not be in the most effective location for meeting this requirement (ie, the Sydney basin).

[53] See discussion in section 6.3.2.

information at this stage in the process may have a material impact on the outcome of those negotiations. However, it should be borne in mind that the costs of generic non-network alternatives are at this stage merely indicative, and need not reflect the final proposed contract prices, which will be used in the final regulatory test assessment.

Given that general information on the potential costs of generation investments is publicly available, but information on the costs of potential DSM activity appropriate for addressing the constraint is still being developed, we consider that it would not be informative to attempt an estimate of DSM activity separately. Rather, we have estimated the costs of a generic non-network option component based upon assumptions about the cost of a generation network support contract (discussed further in Section 6.3.2).

This generic component is intended to act merely as a place-holder, which could represent either generation or DSM. Consequently, significant emphasis should not be placed on the results of the present value analysis at this stage, which are merely indicative.

5.2. Options Assessed Under the Regulatory Test

5.2.1. Potential Options

The following table sets out a 'long list' of potential options.

Table 5.2: 'Long List' of Options

Option 0	09/10:[54] 500kV upgrade
Option 1	08/09: network support (generation and/or DSM) 09/10: 500kV upgrade
Option 2	08/09: network support (generation and/or DSM) 09/10: network support (generation and/or DSM) 10/11: 500kV upgrade
Option 3	08/09: network support (generation and/or DSM) 10/11: 500kV upgrade
Option 4	08/09: network support (generation and/or DSM) 09/10: 500kV upgrade excluding Bayswater Units 3 and 4

[54] The *majority* of construction for the upgrade could be complete by summer 2009/10. See discussion in section 5.1.1.

This list has been reduced to the 'short list' of options considered in the regulatory test application, for the reasons discussed below.

5.2.2. Options included in the analysis

The following table considers the performance of each of the options identified above in each of the market development scenarios set out as set out in Table 4.1, in section 4. In the table, a tick indicates that the option would ensure minimum network performance requirements were met (in all years) in that scenario and a cross indicates that the option would not ensure that minimum network performance requirements were met.

Table 5.3: Performance of options in various scenarios

	Scenario								
Option	**H1**	**H2**	**H3**	**M1**	**M2**	**M3**	**L1**	**L2**	**L3**
0	**û**	**û**	**ü**	**û**	**ü**	**ü**	**ü**	**ü**	**ü**
1	**û**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**
2	**û**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**	**ü**
3	**û**	**û**	**û**	**û**	**û**	**ü**	**û**	**ü**	**ü**
4	**û**	?	?	?	?	?	?	?	?

Several implications are apparent from this table. First, in Scenario H1, none of the options ensure that minimum network performance requirements are met. In Scenario H1, TransGrid would be required to take action in 2007/08, and none of the options we have defined allow for this. We consider, however, that Scenario H1 is unrealistic. In view of poor economic growth in NSW recently,[55] it is unlikely that load will grow sufficiently quickly from current levels to reach the "high" load forecast under H1 in 2007/8. It is our view, then, that the options considered by TransGrid need not ensure minimum network performance requirements are met under Scenario H1.

Second, Option 0 (the 'network-only' option, in which TransGrid carries out the 500kV upgrade by 2009/10) does not ensure that minimum network performance requirements are met in Scenarios M1 and H2 (as well as H1). In both these scenarios, TransGrid would be required to take action in 2008/09. However, the proposed 500kV network upgrade cannot be completed by summer 2008/09, and under Option 0 does not come into operation until 2009/10.

[55] NSW grew by only 0.7 per cent seasonally adjusted in October-December 2005. It had the country's worst annual growth rate, of 2 per cent. *Australian Financial Review*, 2 March 2006, "NSW at the back of the pack".

It is considered that Scenarios M1 and H2 are potentially realistic scenarios. Scenario M1 reflects a medium load growth scenario and the earlier generation scenario, which incorporates patterns of generation which could potentially occur (such as the bringing forward of all 600MW of the Munmorah plant to 2008/9 without any additional generation investment in NSW). Scenario H2 does not necessarily involve high levels of demand until 2008/09 (which we consider more plausible than 2007/08). The occurrence of M1 or H2 appears sufficiently likely for TransGrid to need to plan for the network to continue to meet minimum performance circumstances if these scenarios do eventuate.

The regulatory test makes it clear that as a general requirement under the reliability limb, all options under consideration must address the anticipated inability to meet minimum network performance requirements.[56] We interpret this requirement to mean that all options under consideration must be capable of ensuring minimum network performance requirements are met in all reasonably plausible scenarios. Since Option 0 does not ensure that network performance requirements are met in Scenarios M1 and H2, it will not be considered further.

Option 3 ensures that minimum network performance requirements are met in only a limited number of scenarios. Under Option 3, TransGrid would not take any action to ensure minimum network performance requirements are met in summer 2009/10; Option 3 is therefore ineffective in any scenarios that require action at that time. For this reason, we have chosen not to evaluate Option 3 as a separate option. Nevertheless, Option 3 remains relevant to the analysis, because of its relationship to Option 2.

In some demand / generation development scenarios (Scenarios L2, M3 and L3), the network continues to meet minimum network performance requirements until at least 2010/11. If it becomes apparent at an early stage (say, by mid 2007) that load is growing at a significantly lower rate than expected, and/or that a particularly favourable pattern of generation is emerging, then it would be appropriate for TransGrid to review its investment plans. The most efficient course of action at that stage might be to further defer the 500kV upgrade. Alternatively, TransGrid might find it efficient to decide against proceeding with a non-network alternative (assuming contractual arrangements had not yet been finalised). We have modelled the latter course of action as Option 3.

Since Option 2 and Option 3 incorporate identical action on TransGrid's part in the initial stages, it is possible for TransGrid to choose Option 2 in 2006, and then subsequently switch to Option 3 once new information arrives in, say, mid 2007. This ability exists if TransGrid chooses Option 2, but not if it chooses Option 1.[57] This ability to switch means that the potential cost savings associated with Option 3 should be taken into account to some extent in the regulatory test assessment of Option 2.

The table indicates that the effect of Option 4, the impact of the 500kV upgrade excluding Bayswater Units 3 and 4 is uncertain in most scenarios. As discussed earlier in this section, Option 4 would not be effective in overcoming short circuit rating limitation issues caused by excessive generation capacity locating in certain areas of the network. The uncertainty arises

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[56] Regulatory test clause 3(a)(i)(B)

[57] This difference arises because the lead time for a network upgrade is approximately three years, while the lead time for an OCGT is only two years.

because such problems may or may not be responsible for the inability to meet minimum network performance requirements.[58]

Since Option 4 may not enable the network to meet minimum network performance requirements in some plausible scenarios, it will not be considered further.

The two remaining options are combination options, which include a non-network component in 2008/9 (either a network support contract with a generator or DSM or both) to ensure that minimum network performance requirements are met in that year, followed by network augmentation. Under Option 1, the 500kV upgrade comes into operation in 2009/10. Option 2 includes a further year of network support to defer the upgrade until 2010/11.[59]

Table 5.4: Summary of Options

Option 1	08/09: network support (generation and/or DSM) 09/10: 500kV upgrade
Option 2	08/09: network support (generation and/or DSM) 09/10: network support (generation and/or DSM) 10/11: 500kV upgrade

[58] In the early generation scenario, for example, the inability to meet minimum network performance requirements is triggered *either* when insufficient generation development occurs in 2008/9 within the Newcastle - Sydney - Wollongong area; *or* when generation developments of sufficient capacity occur within the Newcastle - Sydney - Wollongong area, but cause short circuit rating limitations to be exceeded.

[59] To be precise, Option 2 allows the bulk of the 500kV upgrade to be deferred until 2010/11, with the exception of the works at the Bayswater substation, which must be carried out to a specific timetable determined by the requirements of the Bayswater generation units' outage schedule. This issue is discussed further in Section 6.

6. Assumptions Underlying the Analysis

The regulatory test specifies the use of present value analysis as the basis for comparing investment options. Present value analysis allows the comparison of different streams of cash flows by converting all costs and revenues into present day dollar values. We consider the 'present day' to be 1 January 2006 for the purposes of our analysis.

The results of the modelling analysis depend on several key elements, including:

- timing issues, such as the assessed timeframe, terminal values, assumed asset lives and the timing of cash flows within each year (discussed in section 6.1);
- the discount rate used (discussed in section 6.2); and
- the cost assumptions (discussed in section 6.3).

Because of the potential impact that changes in these underlying assumptions may have on the modelling results, sensitivity tests have been carried out to assess whether reasonable changes would alter the rankings of options (summarised in section 6.4).

6.1. Timing

6.1.1. Timeframe of the assessment

There is no set time period over which the assessment should be conducted. Several studies, including the SNI interconnector study, have adopted a ten-year horizon.[60] This is consistent with the network-planning horizon for transmission networks required under the NER.[61] Other regulatory test applications have used longer timeframes (for example, Powerlink uses a 15 year period).[62]

In this assessment, we have used a ten-year horizon. By the end of ten years, the cash flows attributable to the project are expected to have stabilised or be growing at a constant rate, allowing for the use of terminal values.

6.1.2. Terminal values

Terminal values have been used to estimate the value of the cash flows after year ten of the analysis, over the remaining expected life of the assets. These values are calculated as annuities starting in the 11th year and continuing until the end of the asset life.

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60 ROAM Consulting, October 2001, *Description of Methodology for Final Report to NEMMCO and the IRPC, Economic Evaluation of the Proposed SNI Interconnector*, p.5.

61 Op cit, 5.6.2 (d).

62 See, for example, Powerlink Queensland, June 2005, *Application Notice: Proposed New Large Network Asset – Ipswich Area Reinforcement*, p.26.

6.1.3. Asset lives

Asset lives impact the present value by affecting the terminal values, as discussed above. Asset lives for the network augmentation have been provided by TransGrid. These are consistent with TransGrid's accounting requirements.

Table 6.1
Asset Lives

Asset	Assumed Life (Years)
Network Assets	
Substations	30
Lines	45

The actual asset lives are unlikely to be shorter than assumed here; however, sensitivity tests have been carried out to assess the impact of longer lives, 45 years (for substations) and 60 years (for lines).

6.1.4. The timing of cash flows within years

A cash payment late in a year will have different present value implications than an equal cash payment earlier in the year. There is any number of possible combinations and permutations for the expected timing of cash flows. For consistency we have based our assessment on the following timing assumptions:

- capital expenditure for the network augmentation is based on monthly estimates provided by TransGrid;
- other cash flows are assumed to be evenly distributed throughout the year in question, thus they are assumed to occur (on average) in the middle of the year.

6.2. Discount Rate

To compare the cash flows of options with differing time profiles, it is necessary to use a discount rate to convert future cash payments and receipts into present value terms. The choice of discount rate will significantly affect the estimated present value and may impact the ranking of alternatives.

The regulatory test requires that the modelling be conducted using a commercial discount rate appropriate for the analysis of a private enterprise investment in the electricity sector, and that the rate used be appropriate to the cash flows being discounted.[63] We have adopted a (real pre-tax) discount rate of 9 per cent in the base case for the cost analysis. This is consistent with both Powerlink's November 2005 regulatory test assessment for North and

[63] Regulatory test, Clause 10.

Far North Queensland[64] and DirectLink's application of the regulatory test in 2005.[65] Both assessments used a 9 per cent discount rate. The AER in November 2005 considered that this discount rate was 'reasonable'.[66]

The regulatory test requires that sensitivity analysis using alternative discount rates be carried out, and that the lower boundary should be the regulated cost of capital.[67] TransGrid's real pre-tax regulated cost of capital is 6.78 per cent.[68] Accordingly, in this study we apply (real pre-tax) discount rates of 6.78 per cent and 12 percent for the purposes of sensitivity analysis.

6.3. Cost Assumptions

The costs to be taken into account in applying the reliability limb of the test are limited to the following:

- capital costs;
- operating and maintenance costs;
- directly incurred fuel costs (for generation options); and
- environmental costs and subsidies.

As discussed in section 2.2.2, since the 2004 revision of the regulatory test, avoided costs resulting from any impact of an option on the wider electricity market are not taken into account under the reliability limb of the regulatory test, which is restricted to the present value of costs only. Any impact on USE, deferral of generation investment elsewhere in the NEM or transmission losses will not be taken into account. Further, the direct cost of transmission losses associated with any network option should not be taken into account, since to do so whilst ignoring the benefit expected from any network option in terms of reducing overall losses could cause skewed results. [69] This approach has been confirmed with AER staff.

Our cost assumptions are discussed below under each of the following option components:

- network (discussed in section 6.3.1); and
- non-network (discussed in section 6.3.2).

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64 Powerlink Queensland, September 2005, *Application Notice: Addressing Reliability of Supply Requirements in North and Far North Queensland 2007-2010*, p.35.

65 Directlink Joint Venture, September 2004, *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue to 30 June 2015*, p.32.

66 AER, *Directlink Joint Venture Application for Conversion and Revenue Cap*: Draft Decision, November 2005, p120

67 Regulatory test, Clause 15.

68 ACCC, April 2005, *Final Decision, NSW and ACT Transmission Network Revenue Cap, TransGrid 2004–05 to 2008–09*, p20

69 Since losses are a feature of transmission lines but not of non-network options, to take the direct cost of 'internal' losses into account (but not the impact of losses elsewhere in the NEM) could skew the results in favour of non-network options at the expense of network options, even though a network option might well reduce overall losses in the NEM by a greater degree than a non-network option. Similarly, results could be skewed in favour of a smaller transmission augmentation as opposed to a larger one.

6.3.1. Network

6.3.1.1. Network capital costs

TransGrid provided NERA with an estimated capital cost of $310.8 million in total (undiscounted) for the 500kV upgrade, and the timeframe over which this investment would be made.[70] There is always uncertainty in the quantum of capital costs of a project. For this reason we have undertaken sensitivity tests at ±25 per cent of TransGrid's estimates.

Under Option 1, the 500kV upgrade would proceed according to TransGrid's scheduled timing (summarised in Appendix A). Under Option 2, we assume the deferral by one year of all capital expenditure scheduled for October 2006 or later, on all works for the 500kV upgrade, with the exception of the works at Bayswater (which must be carried out to a timetable determined by the Bayswater generation units' outage schedule).

Part of the 500kV upgrade involves replacing two generator transformers at Bayswater. It has not yet been decided whether TransGrid or Macquarie Generation will pay for and own these transformers. However, we consider that the cost of the transformers should be classified as 'direct costs' and added to the base capital costs noted above, regardless of which party pays for them, since they are an integral part of the option. This conclusion is supported by the wording in Item 2(b) of the regulatory test which refers to 'costs incurred in constructing or providing the option', without distinguishing who the costs are incurred by.

The cost of replacing the two new transformers is estimated at $30m, with a sensitivity of ±25 per cent. NERA understands that the generator transformers at Bayswater were installed in the 1980s, are nearing the end of their 30 year life, and would therefore need to be replaced within a few years (we assume the scheduled replacement date is 2014). The 500kV upgrade will therefore only result in the possible 'bring-forward' of those costs by a small number of years. On the basis of information currently available, the costs resulting from the generator transformers at Bayswater have been estimated (in present value terms) as approximately $7.8 million for Option 1 (representing the costs of bringing the investment forward by five years) and $5.9 million for Option 2 (four years). However, this cost estimate may be revised as the result of submissions from interested parties during the consultation period.

Table 6.2 summarises the capital cost assumptions for the network options.

Table 6.2
Network Capital Expenditure Estimates (millions, $2006)

	Lower Bound	Central	Upper Bound
500kV upgrade	$233.1	$310.8	$388.4
Bayswater transformers	$22.5	$30.0	$37.5

[70] The network cost estimates exclude capitalised interest (or 'interest during construction'). The estimates also exclude the cost of replacing two generator transformers at Bayswater; see discussion in this section.

6.3.1.2. Network operating and maintenance costs

We have assumed annual operating and maintenance costs associated with the network augmentation to be 2 per cent of the capital cost. This is based on TransGrid's estimate and is consistent with the assumptions used in other regulatory test assessments.[71]

Since this is a generic estimate which may not reflect actual costs, we have undertaken sensitivity analysis with operating costs at ±25 per cent of this estimate.

6.3.2. Non-network options

6.3.2.1. Approach to costing non-network options

In discussions with NERA, AER staff have given advice on their preferred method for calculating the cost of a non-network option under the reliability limb of the regulatory test. They advised that where a non-network option is to be procured by contracting with a third party to either provide network support (a generator) or DSM capability, the cost of the option in a regulatory test assessment should be calculated on the basis of the price agreed in the contract, rather than a separate calculation of the likely resource input costs.

Given that there are currently no firm proponent(s) for non-network options, and consequently no firm contract prices, we are unable to cost these options on the basis of the contract price approach. In such a situation, we consider that the cost of the option should be estimated, in order to provide a 'ballpark' indication of the possible cost of the option. This estimate has been assessed using calculations of resource input costs, as a proxy for the contract price. However, the final regulatory test analysis will take into account actual or proposed contract prices arising as the result of further negotiations between TransGrid and non-network providers.

Since more information is generally available in relation to generation costs rather than DSM costs, and given the indicative nature of our analysis at this stage, we have based the costs of the generic option on assumptions about the cost of a generation network support contract. As discussed earlier in this paper, TransGrid has received indications of interest in a network support contract from the proponents of three generation investment proposals.

We have focused in this indicative analysis on the likely fixed cost component of a network support contract, which we have assumed would reflect the capital costs of the associated generator. The extent to which the generator would actually be called on to provide network support is highly uncertain, and likely to be limited (since the need for network support is only likely to occur when demand exceeds the 10% POE level, which is already a high threshold). As a result, it is likely that a network support contract would ensure that the generator's fixed costs in providing the contract are covered via a fixed payment, with a variable payment to cover operating costs (including fuel costs) in the event that the generator is called to provide network support. Given that the current analysis is indicative only, we

[71] For example, Directlink Joint Venture, May 2004, *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2005 – 2014*, p.79.

have not attempted to calculate the likely variable payments, which we assume to be small in magnitude compared to the fixed payment.

We note that a DSM contract would also be likely to feature fixed 'availability' payments, not linked to whether or not a DSM provider was actually called on to provide network support. Such payments would cover any capital costs which the provider incurred, but would also provide the incentive for the provider to participate in the program. NERA understands that fixed availability payments are a common feature of DSM contracts in Australia.

In relation to the actual fixed cost we have assumed for a generator network support contract, we note that all three indications of interest received by TransGrid relate to existing publicly announced and/or advanced proposals, with estimated commissioning dates of 2008, 2009 or 2010. Consequently, it is likely that if TransGrid were to contract with a generator for network support, the associated generator would be one which would have entered the generation market in the near future with or without a network support contract. This implies that the fixed network support payments would not be as large as the full capital costs of the generator. Instead, the contract price would need to be just enough to compensate the proponent for the net additional costs incurred by bringing the investment's commissioning date forward to 2008.

The average length of time which a generator would need to be brought forward in relation to the three indications of interest received to date, based on information in the SOO Update, would be one year. Although the commissioning times (and therefore the extent of bring-forward) for each of these generators is not certain, we consider that an assumed bring forward of one year is a reasonable indication of the likely fixed cost of a generation network support contract, for the current purposes.

Since TransGrid has advised that around 350MW additional generation capacity would be required in 2008-09 within the Newcastle - Sydney - Wollongong area (and 700MW in 2009-10), we have assumed that the generator would be a 350MW OCGT. For the purposes of our indicative non-network option component we have assumed that the investment would need to be brought forward by a year.

6.3.2.2. Non-network option: capital costs

The estimated capital cost for the non-network option has been sourced from a report on generation costs prepared for IPART in 2004 by Intelligent Energy Systems.[72] The assumed capital costs of a 350MW OCGT are $753/kW, for a total cost of $263.6 million.[73]

The investment timeframe for construction is assumed to be two years. The capital costs are assumed to be evenly distributed throughout that timeframe, and thus costs are assumed to occur (on average) in the middle of each year. As discussed above, our analysis is based on the cost of bringing forward a generator investment of this magnitude by one year.

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[72] Intelligent Energy Systems, April 2004, *The Long Run Marginal Cost of Electricity Generation in New South Wales*, A Report to the Independent Pricing and Regulatory Tribunal, pp3-17 and 3-18.

[73] This cost has been indexed for two years using CPI. TransGrid has advised that this indexation results in a realistic $/kW capital cost.

Because of the uncertainty around capital cost estimates, we have undertaken sensitivity tests at ±25 per cent of these estimates, as follows:

Table 6.3
Generation Capital Expenditure Estimates

Option	**Lower Bound**	Central	**Upper Bound**
350 MW OCGT	$197.7 million	**$263.6 million**	$329.4 million

6.3.2.3. Environmental costs and subsidies

Under the reliability limb, the regulatory test is satisfied if the option *"minimises the present value of costs".*[74] While benefits are not generally to be taken into account, environmental taxes and subsidies are an exception. The test states that: *"An environmental subsidy should be treated as part of a project's benefits or as a negative cost."*[75]

We have identified two relevant environmental measures:

- the New South Wales Greenhouse Gas Abatement Scheme (the NSW Scheme), which is designed to control greenhouse gas emissions in the NSW electricity industry and results in an indirect environmental subsidy for low-emission generation and abatement projects; and
- the NSW Environment Protection Agency's load based licensing arrangements, which require generators to pay a fee in proportion to their emissions of NO_x, SO_2 and (specified) particulates.

The NSW Scheme applies to both gas generators and some DSM programs, while load based licensing applies only to generation.

We assume that in the event that TransGrid contracts with a non-network counterparty for network support, that counterparty would take the potential revenues from the NSW Scheme and any costs arising from load based licensing into account in its business case, and in its price negotiations with TransGrid. Consequently, it will not be necessary to model the impact of these environmental measures separately at the final stage of the regulatory test assessment.

At the draft stage, we have chosen to focus on the capital costs of a gas generator (as discussed in Section 6.3.2). The effect of both of these environmental measures on a gas generator is to alter its operating costs; the NSW Scheme lowers those operating costs by providing an ongoing stream of income, while load based licensing increases those costs. Neither measure impacts on the capital costs of a gas generator.[76] Consequently, we have not

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[74] ACCC regulatory test – Version 2, (1) (a)

[75] ACCC regulatory test – Version 2, (2) (c)

[76] The effect of the NSW Scheme on a DSM program is a one-off subsidy, rather than an ongoing stream of income. However, given that we are not modelling DSM option components separately at this stage, we have assumed that this difference is immaterial.

modelled the impact of these environmental measures separately at this draft stage of the regulatory test assessment.

6.4. Sensitivity Tests – Summary

The regulatory test requires sensitivity tests be conducted on key input assumptions.

The rationale behind the sensitivity tests has been outlined in the above sections. The following table summarises the sensitivity tests NERA has considered in its analysis.

Table 6.4
Sensitivity Tests

	Lower Bound	Central (used in "Base" case)	**Upper Bound**
Discount rate	6.78%	**9%**	12%
Capital Expenditure Relative to base assumption	-25%	**-**	+25%
Operating Expenditure Relative to base assumption	-25%	**2% of capex**	+25%
Asset Lives Substations Lines		**30** **45**	45 60

7. Results

7.1. Introduction

This section sets out the results of the preliminary regulatory test analysis.

As discussed in section 5, NERA has evaluated two alternative options for meeting minimum network performance requirements from 2008/9 onwards. Both of these options involve non-network support in 2008/9. Option 1 then involves the 500kV upgrade in 2009/10. Option 2 involves further non-network support in 2009/10, followed by the 500kV upgrade in 2010/11. Both of these options have been assessed under the nine market development scenarios identified in section 4.

The market development scenarios (as set out previously in Table 4.1) do not impact the cost of the options, so the present value results are the same under all scenarios.[77]

As discussed in Section 5, the options considered in this report should be considered as indicative only at this stage. In particular, the costs of the non-network component(s) of the options reflect the costs of an assumed generation option, which may bear no resemblance to actual contractual arrangements agreed between TransGrid and either a generator or a DSM proponent. Given that commercial negotiations are expected to be on-going between TransGrid and potential non-network providers between this Draft Report and the final regulatory test assessment, we consider an approach based on a generic option to be appropriate at this stage.

However, given the generic nature of the non-network component, significant emphasis should not be placed on the results of the present value analysis at the draft stage, which are merely indicative. It is expected that the options evaluated in the final regulatory test analysis will reflect actual non-network options offered by proponents.

7.2. Results Summary

Table 7.1 below summarises the results of the financial modelling for the options under the base case. We have calculated the present value of the costs of both options over a ten-year period, with terminal values to capture residual network opex values.

Table 7.1: Comparison of Option Results (present values)

Options	Costs: PV ($M)	Rank
Option 1: 500kV Upgrade in 2009/10	320	2
Option 2: Upgrade deferred to 2010/11	317	1

[77] However, see the discussion of Option 2's 'strategic advantage' in section 7.2.

Additional detail on the financial modelling, including the timing of the cash flows, is provided in Appendix A.

Our "base-case" modelling indicates that the least cost option is Option 2, which involves TransGrid contracting with non-network providers (including generation and / or DSM providers) in order to meet minimum network performance requirements in 2008/09 and 2009/10, followed by completion of the 500kV upgrade by 2010/11.

Since Option 2 minimises the present value of costs (compared with Option 1) in a majority of reasonable scenarios, our draft result is that Option 2 would satisfy the regulatory test.[78] However, given the generic nature of the non-network component of the options, significant emphasis should not be placed on the result at this stage.

Box 7.1.
Impact of Future Network Development

As discussed in Section 4.5, TransGrid currently expects that there will be a need to build a new 500kV transmission line sometime within the next ten years. At this stage there are two alternatives for this development: Bayswater – Eraring and Bannaby - Kemps Creek.

Importantly, the option which is undertaken in order to address the currently identified inability to meet minimum network performance requirements in 2008/09 will have no impact on either the timing or the nature of the later required transmission development.

As discussed in section 4.5 the cost of the additional network development has not been included as part of the cost of the options being assessed under this application of the regulatory test.

Given the independence of the "second stage" network development, if the costs were to be included in the regulatory test assessment for the current options, they would increase the cost of all options by an identical amount. According to TransGrid's desk-top estimates, this amount would be either $280 million, if the 'second stage' 500kV development option selected is Bayswater – Eraring, or $300 million for Bannaby - Kemps Creek.[79]

As such, there would be no impact on the ranking of the options. For example, the present value of the $300 million Bannaby - Kemps Creek development (assuming the capex is equally spaced over the three years from 2011 to 2013), is approximately $172 million. If we revised the base results reported above to take this value into account, it would result in present values of $492 million for Option 1 and $489 million for Option 2. The relative cost difference between the options, and the rankings, are unchanged.

A further consideration not captured in the present value analysis presented above, is that, as discussed in Section 5, Option 2 has additional strategic advantage because it preserves

[78] See previous discussion on the reliability limb of the regulatory test in section 2.2.

[79] These desk-top" estimates have an accuracy of +-50%.

TransGrid's ability to react to changing circumstances – by switching to Option 3. Option 3 is likely to be the least-cost option; however, since it ensures that minimum network performance requirements are met in only a limited number of scenarios, we have not evaluated it as a separate option.

Nevertheless, the ability to switch to Option 3 provides TransGrid with an additional cost saving in the event that certain scenarios emerge, if it has chosen Option 2 (but not if it has chosen Option 1). We have estimated the potential cost reduction at approximately $17 million (which represents the reduction resulting from a decision not to proceed with an additional non-network alternative in 2009/10).

We have chosen not to incorporate this figure into the present value modelling for Option 2 due to the difficulty of quantifying the likelihood that scenarios emerge in which Option 3 would be possible. However, this potential reduction increases the possibility that Option 2 is the most efficient option.

7.3. Sensitivity Analysis

Sensitivity tests have been undertaken to assess the effect on the present value results of reasonable variations in the underlying assumptions. The sensitivity tests have been outlined in section 6.4.

The impact on the present values of a selection of sensitivity tests are presented in Chart 7.1.

Chart 7.1.

These sensitivity tests have been run "one at a time" to test the impact on the present value results of individual assumptions. The sensitivity analysis indicates that the ranking of the options is robust to most reasonable changes in individual assumptions; however the rankings are reversed, and Option 1 becomes the first ranked option, if it is assumed either that:

- network capital costs are 25% lower than expected; or
- non-network capital costs are 25% higher than expected.

This reflects the high weighting of the network augmentation (and low weighting of the non-network component) in the costs of Option 1 relative to Option 2 (which involves deferring the network for an additional year by spending funds on an additional non-network component).

This potential reversal in the rankings suggests that the accuracy of TransGrid's network capital cost estimates and the cost estimates for the non–network components are likely to be crucial to the decision taken at the final stage of the regulatory test application.

The results of the sensitivity testing are also presented in numerical form in Appendix A.

8. Conclusions

Our draft application of the regulatory test indicates that the least cost option is Option 2, which involves TransGrid contracting with providers of non-network alternatives (including generation and / or DSM) in order to meet minimum network performance requirements in 2008/09 and 2009/10, followed by completion of the 500kV upgrade by 2010/11. The potential for an additional saving resulting from increased flexibility to respond to changing circumstances increases the extent to which Option 2 would be preferred over Option 1.

However, given the generic nature of the non-network component of the options, significant emphasis should not be placed on this draft result. It is expected that the options evaluated in the final regulatory test analysis will reflect contractual terms negotiated with actual proponents for non-network options, and those terms will reflect factors which have not been captured by our indicative modelling. For example, the non-network costs used in our modelling are based on the cost of bringing forward the construction of a 350 MW OCGT; these might be too low if TransGrid were negotiating for the provision of network support by a larger generator, or by a CCGT. If TransGrid contracts with a provider of DSM, on the other hand, the contractual terms will reflect quite different factors, and could be lower than our estimates.

Nevertheless, we can draw some conclusions from the indicative results.

First, the pattern of generation investment that occurs in NSW will have a significant impact on the time at which the existing network will no longer meet minimum network performance requirements. Consequently, in choosing an option, TransGrid must give careful consideration to possible generation developments. We consider that TransGrid must *either* choose an option that ensures the network will meet minimum requirements in all the realistic scenarios we have outlined in this report,[80] *or* come to a view that some of the generation and/or demand scenarios outlined in this report are not realistic. If TransGrid is comfortable with such a view, then its chosen option need not meet minimum network performance requirements in such scenarios.

Second, there is potential value in the short term in non-network alternatives to the 500kV upgrade. Since it appears at this stage that the 'network-only' option, in which TransGrid carries out the 500kV upgrade by 2009/10, would *not* ensure that minimum network performance requirements were met in some scenarios, the feasible options are restricted to combination options which incorporate non-network alternatives (generation or DSM), followed by the 500kV upgrade in either 2009/10 or 2010/11.

Third, it is a distinct possibility that to delay the conversion by an additional year from 2009/10 to 2010/11 will prove to be the most efficient option in the final stage of this regulatory test application. This underlines the importance of TransGrid's ongoing discussions with potential providers of generation and DSM, and implies that those discussions should be undertaken with a number of potential providers, with a view to implementing non-network alternatives in *both* 2008/09 and 2009/10.

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[80] That is, all scenarios except H1, which we do not consider realistic.

Finally, given that the present values of the two options are very close together, TransGrid cannot at this stage eliminate Option 1 from consideration. The identified possibility of a reversal in the option rankings (in the case of lower than expected network capital costs or higher than expected non-network capital costs) reinforces this point.

Appendix A. Present Value Analysis

The tables in this appendix provide further detail on the present value results presented earlier in this report.

Table A.1: Results for base case assumptions

Options	Costs: PV ($M)	Rank
Option 1: 500kV Upgrade in 2009/10	320	2
Option 2: Upgrade deferred to 2010/11	317	1

Table A.2: Present Value summaries

Option 1: Upgrade in 2009/10													
Cashflows/Year Ended June	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Terminal**		**PV**
Network Capital Expenditure	$5,252,619	$37,213,381	$152,061,731	$114,064,041	$2,162,862							*	$253,919,173
Opex	$0	$0	$0	$3,937,111	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$60,698,844		$48,091,312
Total	$5,252,619	$37,213,381	$152,061,731	$118,001,152	$8,377,955	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$60,698,844		$302,010,485
PV (Network)	**$302,010,485**	*											
Non-network component of Option 1	**$18,336,290**												
PV of Option 1	**$320,346,775**												
		** includes additional $7.8 million due to bring-forward of Bayswater transformers by 5 years*											

Option 2: Upgrade deferred to 2010/11													
Cashflows/Year Ended June	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**Terminal**		**PV**
Network Capital Expenditure	$3,931,965	$19,385,697	$74,942,207	$97,070,612	$113,492,033	$1,932,120						**	$237,163,267
Opex	$0	$0	$0	$1,538,675	$3,937,111	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$61,210,496		$44,978,678
Total	$3,931,965	$19,385,697	$74,942,207	$98,609,286	$117,429,144	$8,147,213	$6,215,093	$6,215,093	$6,215,093	$6,215,093	$61,210,496		$282,141,945
PV (Network)	**$282,141,945**	**											
Non-network component of Option 2	**$35,158,574**												
PV of Option 2	**$317,300,519**												
		*** includes additional $5.9 million due to bring-forward of Bayswater transformers by 4 years*											

Table A.3: Sensitivity test results

Panel 1: Description of Scenario

Changing Variable	Base Case	Lower Bound Discount Rate	Upper Bound Discount Rate	Low Capex - Network	High Capex - Network	Low Opex - Network	High Opex - Network	Low Capex - Non-Network	High Capex - Non-Network	Long Asset Lives - Network
	Scenario Name									
WACC	0%	-2.2%	3.0%	0%	0%	0%	0%	0%	0%	0%
Network capital costs	100%	100%	100%	75%	125%	100%	100%	100%	100%	100%
Network operating costs	100%	100%	100%	100%	100%	75%	125%	100%	100%	100%
Generation capital cost	100%	100%	100%	100%	100%	100%	100%	75%	125%	100%
Line lives	45	45	45	45	45	45	45	45	45	60
Substation lives	30	30	30	30	30	30	30	30	30	45

Panel 2: Results of Scenario Testing

	Base Case	Lower Bound Discount Rate	Upper Bound Discount Rate	Low Capex - Network	High Capex - Network	Low Opex - Network	High Opex - Network	Low Capex - Non-Network	High Capex - Non-Network	Long Asset Lives - Network
	Scenario Name									
PV: Cost ($M)										
Option 1: Upgrade in 2009/10	320	345	295	245	396	308	332	316	325	323
Option 2: Upgrade deferred to 2010/11	317	342	292	258	377	306	329	309	326	320
Rankings										
Option 1: Upgrade in 2009/10	2	2	2	**1**	2	2	2	2	**1**	2
Option 2: Upgrade deferred to 2010/11	**1**	**1**	**1**	2	**1**	**1**	**1**	**1**	2	**1**

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