Ernst & Young

Review of the Assessment Criterion for New Interconnectors and Network Augmentation

Final Report
to
Australian Competition and Consumer Commission

March 1999

Executive Summary

Background and Scope

The subject of this report is the decision criterion, expressed in the National Electricity Code, used to establish the regulated status of transmission augmentations. The report was commissioned by the ACCC, as part of a combined review of the decision criterion and its own regulated asset valuation methodology. That review included public consultation.

The review is concerned with the relationship between regulated transmission revenue and the process by which new transmission investment is approved. Although linked, these two elements of transmission regulation are dealt with in separate chapters of the Code.

Need for Change

The current Code (in chapter 5) contains ambiguous and potentially inappropriate directions for deciding whether or not a transmission augmentation may be deemed a regulated asset (and thereby contribute to its owner's regulated revenue). Wording in the current Code refers to benefits to Customers - where these are defined essentially to be energy "retailers". As referred to above, the ACCC is currently developing its regulatory valuation guidelines.

This Report

In this report, we propose an evaluation framework (chapter 3), then assess a wide range of options and issues against this framework. The majority of this report covers the design of the benefits test (chapter 4) and the valuation of regulated assets (chapter 5). In chapters 6 and 7 we note some implementation issues, including particularly the roles and responsibilities and note linkages between this review and others which are in progress.

In the context of this review, this is a final report setting out our conclusions and recommendations on the relevant issues. It follows very closely the format of our draft report (published at the end of November 1998), and incorporates feedback obtained during a public forum and from written submissions during December 1998 and January 1999.

Recommendations

Augmentation Test

We propose the following.

- The chapter 5 transmission augmentation criterion should be based on net benefits accruing to generators and customers (both wholesale and retail).

- The relevant benefits to measure are those that can also be captured by non-regulated alternatives: for example, savings in costs associated with energy and ancillary services, and improvements in reliability, priced at a level consistent with spot market mechanisms. Only those "external" benefits and costs which are the subject of current or reasonably-anticipated government laws and regulations, and therefore required to be factored into investment decisions - such as Environmental Protection Authority requirements - should be included within the analysis.

- The test should require an augmentation to maximise benefits. This should mean that the proposed augmentation delivers more anticipated benefits than any identifiable alternative across a range of (although not necessarily all) forecast scenarios.

Asset Valuation

We propose the following.

- For the purposes of this report, asset valuation and re-valuation (ie optimisation) by the ACCC should be seen as a mechanism for sharing, between the TNSP and market participants, the risk that the market benefits identified by the augmentation test do not eventuate.
- The fact that the test has been passed does not necessarily mean that the TNSP should be insulated from any further benefits-related risk, although this is one possible outcome. The appropriate allocation of risk is a matter for the ACCC. However, it is important that the basis for any future re-valuations should be known and clear to the TNSP at the time of the augmentation: this may be through the ACCC's SRI, or agreed bilaterally on a case-specific basis.
- If the ACCC were to adopt the ODV (or another valuation) methodology, its calculations should be consistent with the calculations undertaken in the augmentation test: for example, the same categories of benefit should be captured for the purposes of calculating Economic Value and the same type of modelling should be used.
- Care should be taken in applying ODV to ensure that the TNSP is not impacted simply due to a mismatch between the timing of benefits and the depreciation schedule adopted to determine allowable revenue. We have suggested a number of approaches to ensure consistency between the augmentation test, ODV and revenue setting.

Recommended Guidelines for the Augmentation Test

The guidelines which follow are intended to provide assistance to those drafting Code or other regulatory changes. They have not been subject to legal review and Ernst & Young accepts no responsibility in the event that these guidelines are incorporated into any legally binding document.

The decision to permit regulated transmission augmentation should satisfy the following principles and conditions:

1. The analysis supporting a decision to permit regulated transmission augmentation should broadly mimic an economic investment analysis on behalf of a hypothetical person comprising all electricity producers and consumers and network providers in the NEM.

2. To pass the test, the proposed augmentation should maximise the net present value of total benefits to electricity consumers and producers and network providers (or total economic surpluses in the NEM) based on the proposed augmentation cost and reasonable forecasts of:

   - electricity demand
   - the value of energy to electricity consumers
   - the capital and operating costs of supplying energy and ancillary services to meet the forecast demand, consistent with the relevant reliability standards
   - the capital and operating costs of other network augmentations consistent with the forecast demand and generation scenarios

3. All the costs identified above should include the relevant costs of compliance with existing (or realistically anticipated) laws, such as those relating to health and safety, land management, environmental pollution abatement, etc. The costs of intangibles over and above those required for compliance with existing or anticipated laws should not be included.

4. Similarly, any intangible benefits, which cannot reasonably be quantified in terms of cash flows to an electricity producer or consumer should not be included.

5. The present value of net benefits should be calculated using a discount rate appropriate for commercial investment analysis in the electricity sector.

6. The analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres and various potential generator investments and realistic operating regimes. These market expansion plans should include:

   - already committed projects,

- anticipated projects, which are at an advanced stage of planning (and which are likely to have expected commissioning dates within the next 5 years approximately),
- modelled projects, which may comprise generic generation and other investments (based on projected fuel and technology availability), and likely to be commissioned (in response to growing demand or as substitutes for existing generation plant) in addition to committed and anticipated projects.

7. Notwithstanding paragraphs 1 and 2 above, two types of market expansion plans should be explicitly considered: least-cost expansion and market-driven expansion. Least-cost expansion models the investments and behaviour of a hypothetical person comprising all consumers and producers in the NEM, while market-driven expansion models the dynamic response of producers and consumers to price and quality of service. If the NEM were a perfectly efficient market, these two expansion models would be similar. However, to the extent that market imperfections exist and can be modelled, the market-driven expansion may be different to a least-cost expansion.

8. The proposed augmentation need not record the greatest net benefit (total economic surplus) over all expansion scenarios, but should be reasonably considered to have the greatest overall net benefit, after taking account of credible scenarios. In other words, the word “maximise” in paragraph 2 above need not have a strict interpretation.

9. Scenarios in which the proposed augmentation is commissioned later than proposed should be explicitly assessed. The test should seek to confirm that the proposed augmentation maximises net benefit with respect to its timing as well as with respect to alternative expansion scenarios.

10. The proposed augmentation should not unreasonably pre-empt or distort potential unregulated investments (either generation, network, or demand-side investments) which have yet to be identified. To this effect, a proposed transmission augmentation should not be granted regulated status significantly in advance of its latest possible commitment date (ie the date at which the project must be committed in order to just meet the optimal commissioning date).

1. Background, Scope and Process

Ernst & Young has been engaged by the Australian Competition and Consumer Commission (ACCC) to review the assessment criteria for transmission augmentations and the associated assets' value for the purposes of determining the owners' regulated revenue. This report has been prepared as part of that engagement, and its purpose is to summarise and discuss the views of stakeholders on these issues, and to make specific recommendations on each of them.

This section sets out the background to the review; it describes the ACCC's public consultation process on the issues, and the sorts of outcomes which might be consequent upon the consultation process.

1.1. Background

1.1.1. ACCC's role in transmission revenue regulation

The ACCC will assume responsibility for regulating transmission revenue in the National Electricity Market, on a progressive basis, with effect from 1 July 1999. As envisaged in the National Electricity Code (hereafter referred to as "the Code"), the ACCC is developing a Statement of Regulatory Intent (SRI), that is a set of guidelines, outlining how it will exercise its powers to regulate transmission revenues.

In May 1998, the ACCC published an issues paper which canvassed a range of options indicating how it intends to exercise its regulatory discretion regarding maximum allowable revenue for transmission network service providers (TNSPs). That paper indicated a (preliminary) preference for an accrual building block approach, which relies heavily on asset valuation. Further, that paper indicated a preference for the Optimised Deprival Valuation (ODV) methodology[1].

The ACCC's regulatory roles and the SRI relate to chapter 6, part B of the Code. There are, however, clear links between the transmission revenue regulatory aspects of the Code and other parts of the Code, particularly the chapter 5 elements relating to network planning and augmentation.

Chapter 5 of the Code establishes several avenues for planning and undertaking network investments, including regulated and unregulated options. Regulated assets earn a regulated return in accordance with chapter 6 of the Code, while unregulated assets earn a return through transactions in the market.

Chapter 5 describes a number of decision processes and criteria, under which transmission augmentations may become part of a TNSP's regulated asset base. In essence, an augmentation may receive approval to enter the regulated asset base (before it is built) if it passes a "public benefits test"[2]. In the case of augmentations which may affect transmission between regions, this test must be administered by the National Electricity Market Management Company (NEMMCO).

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[1] The ODV methodology is described in section 5.1
[2] The precise form of the test and the definition of public benefit are the subject of this review

Although an asset may have been approved as a regulated asset under chapter 5, it must enter a TNSP's regulated revenue base at a value determined in accordance with the valuation methodology adopted by the ACCC. The Code acknowledges the potential for inconsistency between the ACCC's valuation methodology (applied under chapter 6) and the "public benefits test" applied under chapter 5. To address this concern, it requires the ACCC to have regard to the need to value assets created under NEMMCO's determination (under chapter 5) in a manner consistent with that determination[3].

Accordingly, the ACCC wishes to ensure that the decision criterion, explicit or implicit in the asset valuation methodology it adopts (whether ODV or another approach), will be consistent with the decision criterion employed to create new regulated assets under chapter 5.

1.1.2. SANI

In June 1998, NEMMCO published its review of a proposed inter-connector between South Australia and New South Wales, known as "SANI". Although the National Electricity Market (NEM) had not commenced at the time, NEMMCO was asked to perform an assessment of the SANI proposal, and to follow a Code-compliant process. The objective was to ensure that the project was justified under the Code, and provide confidence that it would enter the relevant regulated asset base. In some respects, NEMMCO's review can be regarded as a "test run" for the Code's chapter 5 provisions.

As part of its review, NEMMCO considered the decision criterion for determining whether a proposal for an inter-regional augmentation may be deemed a regulated asset. NEMMCO noted that the Code contained some ambiguities in this regard, in some clauses referring to public benefit and in others to *Customer* benefit (where the italics confer the status of a defined term in the Code). NEMMCO also noted several issues, of principle and procedure, associated with identifying and measuring certain costs and benefits. Ultimately NEMMCO found that SANI was not justified, according to its legal and economic interpretations of the test, as set out in the current Code.

Additionally, in its review of SANI, NEMMCO found the *Customer* benefits test to be highly volatile, which might make it difficult for any proposal for inter-regional augmentation to satisfy the criterion. This conclusion has raised general concern that new investment - at least that seeking regulated status - is effectively blocked, with significant implications for the continued efficiency and reliability of the national grid.

This concern is highlighted by its lodgement on NEMMCO's Issues Register by the NSW Government. The issue was given a "critical" status and was due to be resolved before market start.

At the same time, and in spite of NEMMCO's conclusion, others expressed a different concern - that over-investment in regulated assets could result from a test which is biased towards that form of investment.

[3] Refer to Code clause 6.2.3 (d) (4) (ii)

No matter which concern has greatest validity, a review of the current decision criterion is certainly warranted. The review is intended to assist resolution of the issue registered by the NSW Government, and if necessary to clarify the decision criterion so that future applications (for regulated transmission assets) may proceed more efficiently and with greater certainty for all stakeholders. While Code changes are a matter for the National Electricity Code Administrator (NECA), the ACCC is looking to develop its valuation methodologies (in relation to the SRI) in order to facilitate a timely and consistent overall solution

1.2. Scope of this Review

In response to the background issues described above, the ACCC initiated a review (including public consultation) focussing on the augmentation decision criterion, from the perspectives of both chapter 5 and chapter 6 of the Code. The ACCC engaged Ernst & Young to assist with the review.

This section outlines the scope of that review, and the consultation process.

In essence, the scope of the review is to assess the appropriateness of the decision criterion, as currently expressed in chapter 5 of the Code, and if necessary to recommend an alternative criterion. In addition, the review will recommend an approach to the valuation of transmission assets, which may ultimately be expressed in the ACCC's SRI, to ensure consistency with the chapter 5 decision criterion.

This review is not intended to be a comprehensive review of chapter 5 of the Code, nor is it intended to provide a complete description of the ACCC's valuation methodology. Specifically, related details such as who should perform the chapter 5 test, and what process they should follow, are not included in the scope.

Nevertheless, we acknowledge that these issues may be relevant to this review and accordingly we have made some comment on them in section 6 of this report. Also, we are aware of parallel work-streams considering other related issues - for example, the definition of transmission services and transmission pricing details, the status of unregulated inter-connectors, and "top-end" market issues concerning reliability and the price cap. The relevance of those issues to this review is discussed briefly in section 7.

1.3. Consultation Process

This section outlines the process which the ACCC has initiated in relation to this review.

The review began in October 1998 when the ACCC posted draft terms of reference for a consultant to assist with the review. The ACCC requested submissions on the issues and invited proposals.

Ernst & Young were engaged at the end of October, and proceeded to:

- review NEMMCO's recent determination on the SANI proposal, and all relevant background papers, in regard to the decision criteria and decision methodology used,

- review written submissions to the ACCC's terms of reference for this review, and to its issues paper (in regard to its SRI), relevant to transmission augmentation and asset valuation,
- meet with and discuss the relevant issues with selected stakeholders (including the ACCC, NECA, state jurisdictions, NEMMCO, TNSPs, and selected generators, retailers and electricity consumers).

The information gathered during this phase of the review provided the input for a draft report, which was published at the end of November 1998. Following publication of the draft report, the ACCC called for written submissions on the issues, and conducted a public forum on 7th December 1998 in Canberra. Fourteen written submissions were received.

Ernst & Young has considered the written submissions together with views expressed at the public forum, in the preparation of this report to the ACCC. The majority of submissions were generally very supportive of the draft report, both in terms of its coverage of the issues, and of its recommendations. Accordingly, this report does not differ substantially - in terms of format or content - from the draft.

However, some respondents made several specific criticisms and drew attention to concerns which were not adequately addressed in the draft report. In response to those concerns we have endeavoured to clarify, refine, and extend the discussion contained in the relevant sections of the draft report. We have not included a summary of the written submissions, nor have we attempted to respond to each one individually.

This being the final report, we have also included a section (as Appendix 3) which summarises (in one place) our recommendations for the transmission augmentation decision criterion and associated guidelines.

As noted in the draft report, the review process is intended to highlight specific deficiencies (or not, as the case may be) with the current Code, and to recommend appropriate alternative expressions (if necessary) for the chapter 5 decision criterion. Subsequent to the ACCC initiating this review, in December 1998 NEMMCO submitted a code change proposal to NECA, relating to the Code's chapter 5 augmentation decision criterion. It may be expected that this report will contribute to that code change process.

In addition, it may be expected that the ACCC will draw on relevant recommendations provided in this report when it prepares its SRI.

2. Current Augmentation Processes

This section summarises the transmission augmentation processes as they are currently provided for in the Code. It also outlines the current Code provisions for regulated asset valuation and allowable revenue, and transmission pricing.

2.1. Investment Decision Processes

Chapter 5 of the Code establishes four avenues for planning and undertaking network augmentation[4], namely:

1. as a response to a new or modified connection (eg a growing load);

2. following a network's annual review of planning within a region;

3. by NEMMCO and the inter-regional planning committee (IRPC), which must undertake an annual review of the transmission networks and determine whether an augmentation is justified (including any augmentation proposals voluntarily submitted for review by an NSP) and allow the costs to be included in the revenue cap; and

4. by the IRPC and NEMMCO which *must* assess all new inter-connectors for the purposes of maintaining the service standards of existing code participants and which *can* also assess the economic justification of a new inter-connector and allow the costs to be included in the regulated revenue cap.

In effect, therefore, chapter 5 of the Code establishes mechanisms to allow for investment in both regulated and unregulated transmission assets. Regulated assets earn a regulated return in accordance with Chapter 6 of the Code, while unregulated assets earn a return through transactions in the market.

We note that chapter 5 of the Code comprises separate clauses covering development of networks within a region, the role of the IRPC in transmission planning concerning power transfer within and between networks, and applications to establish new interconnectors. However, it is not clear where the distinction lies (if any) between intra-regional and inter-regional augmentations.

Clause 5.6.2 provides for a TNSP to undertake augmentations (and also generation investments as substitutes for network augmentation) after consultation with affected *Code Participants* and after conducting a *Customer* benefit test.

However clause 5.6.5 provides for the IRPC to co-ordinate planning across all transmission systems, to conduct *Customer* benefits tests, and to make recommendations to NEMMCO in regard to augmentations and practicable alternatives to network augmentation. NEMMCO must then decide if an augmentation recommended by the

[4] Note that network *augmentation* is any investment which increases service levels, as distinct from asset replacement and refurbishment, which maintains existing service levels.

IRPC is justified (using a *Customer* benefits test). This clause does not provide for NEMMCO to authorise alternatives to network augmentation, such as a generator.

It is not clear where the boundary lies between the responsibilities of a TNSP under clause 5.6.2 and those of the IRPC and NEMMCO under 5.6.5. We believe that the intention is that clause 5.6.2 should cover network augmentations which do not materially affect power transfer (or cost allocation) between regions.

Clause 5.6.6 provides for NEMMCO and the IRPC to review applications to establish an *interconnector* (which is defined as a transmission line which connects the transmission networks in adjacent regions). NEMMCO may determine that the interconnector is justified (using a *Customer* benefit test) if the applicant were seeking regulated status.

It is not clear (to us) whether the term *interconnector* is intended to mean a specific asset which crosses a region boundary, or any asset which can affect power transfer between regions. If the latter, there would appear to be some overlap between clauses 5.6.5 and 5.6.6.

Notwithstanding these uncertainties, the following table summarises what we believe to be the various augmentation processes provided in chapter 5 of the Code. It highlights the roles of augmentation proponents, the IRPC, NEMMCO, TNSPs, and the ACCC (under chapter 6).

Transmission Investment Types and Current Decision Process

	Type of Investment	Proposed by:	Analysed by:	Decided by:	Decision Rule	Regulated asset valuer:
a	Replacement and refurbishment of existing assets[5]	TNSP	TNSP	TNSP	Unspecified	ACCC
b	Regulated Intra-regional augmentation[6]	TNSP[7]	TNSP (with public consultation)	TNSP (with agreement from affected parties)[8]	*Customer* benefit	ACCC
c	Regulated Inter-regional augmentation[9]	Developer or TNSP or IRPC[10]	Proponent, IRPC, NEMMCO (with public consultation)	NEMMCO (reviewable by *Tribunal*)[11]	*Customer* benefit	ACCC
d	Unregulated Inter-regional augmentation	Developer	Proponent[12]	Proponent (NEMMCO decides if augmentation meets technical standards)[13]	Unspecified	N/A

[5] Chapter 5 explicitly provides for augmentation or extension, but not the refurbishment and replacement of transmission assets
[6] An intra-regional augmentation is not well-defined in the Code, but we interpret it as any augmentation which is deemed to have little or no effect on transmission between regions. The Code appears to make no provision for unregulated intra-regional network assets.
[7] A TNSP need not also be the network asset owner (such as is the case in Victoria).
[8] As per clause 5.6.2 (j) and (l)
[9] An inter-regional augmentation is any augmentation which affects power transfers between regions.
[10] Clause 5.6.5 of the Code provides for the IRPC to identify, and for NEMMCO to decide, that an augmentation is justified and necessary even if no TNSP or other party has proposed to build it. If a TNSP identified by NEMMCO declines to build it, liaison with the relevant regulator and mediation must take place to resolve the dispute.
[11] Clause 5.6.5 (p). The *Tribunal* is the National Electricity Tribunal established under Part 3 of the National Electricity (South Australia) Act 1996 of South Australia.
[12] An inter-connector may be unregulated because the developer did not apply for regulated status, or because regulated status was declined by NEMMCO.
[13] As per clause 5.6.6 (e)

2.2. Inclusion in Regulated Asset Base

The ACCC's issues paper (in relation to its SRI) proposes that a TNSP's maximum allowable revenue (MAR) will be agreed at the start of each regulatory period. The paper proposes that the MAR be reviewed at the beginning of each regulatory period, which will be every five years. If the MAR were based on asset valuations (as per the ODV methodology), this would imply five-yearly asset re-valuation.

Although, in order to provide tariff and revenue stability, forecast capital expenditure (for the following five years) can and should be included in the MAR, this capex forecast need not pre-empt the Chapter 5 process. Specifically, including a proposed augmentation in the capex forecast does not imply that the augmentation should or will go ahead (and vice versa). Adjustments to claw back revenue for forecast capex not actually undertaken (or to recover revenue for capex undertaken but not forecast) can be made at the end of the regulatory period and carried forward into the MAR for the next period.

However, whether or not the ACCC allowed forecast capital expenditure to be included in the MAR, its inclusion at the beginning of subsequent regulatory periods may be subject to it passing a "deprival value" test. Again, the Code requires that this value be derived in a manner consistent with NEMMCO's determination, but it does not exclude the possibility of a different value.

There are several issues here:

1. Under what circumstances might it be appropriate for regulated assets to be approved under the chapter 5 augmentation test but disallowed (or written-down in value) under the chapter 6 valuation?
2. Should the augmentation test "tie the ACCC's hands" to some extent: for example by requiring it not to re-value any augmentation that has passed the test, or not to revalue within a certain period? Or is the augmentation Test simply an "entry" test, *allowing* the relevant assets to be regulated, but not having any implications for *how* those assets should be regulated?
3. To the extent that the augmentation test does dictate - to some extent - how the assets should be regulated, to what extent should the ACCC be involved in the test? If they are not involved, does this mean that they just have to, effectively, re-apply the test at a later date, and could this undermine the purpose and relevance of the Code test?

These issues are addressed in sections 5 and 6 of this report.

3. An Evaluation Framework

An evaluation framework is needed in order to structure the issues and assess the merits of different proposals and options (relating to network augmentation decision criterion and asset valuation). This section describes the framework we have adopted, and links each element of that framework to sources in the Code, to which we looked for relevant objectives and principles.

Having considered the code objectives and principles for regulation of networks, we have adopted a framework in which to evaluate the relevant issues. The criteria we adopted are:

- Competitive neutrality
- Economic efficiency
- Practicability and simplicity
- Regulatory certainty

These are described below.

3.1. Competitive Neutrality

This criterion follows directly from the code objectives of competition, customer choice, and non-discrimination. It implies that the decision criterion should not favour one group of generators over another, nor should it favour (or disfavour) regulated transmission options over other investment options.

Clause 1.3 (b) states the market objectives as follows:

(1) the *market* should be competitive;

(2) customers should be able to choose which supplier (including generators and retailers) they will trade with;

(3) any person wishing to do so should be able to gain access to the *interconnected transmission* and *distribution network;*

(4) a person wishing to enter the *market* should not be treated more favourably or less favourably than if that person were already participating in the *market*;

(5) a particular energy source or technology should not be treated more favourably or less favourably than another energy source or technology; and

(6) the provisions regulating trading of electricity in the *market* should not treat intrastate trading more favourably or less favourably than interstate trading of electricity.

3.1.1. Generation Competition

We note that the market referred to in the Code is essentially the spot market for electrical energy. In regard to regulated transmission and competition in the market, we have approached the neutrality question from the point of view that regulated transmission does not compete directly with generation, but it does affect (indeed it effects) competition between generators.

Our main concern, therefore, is to ensure that the regulated transmission investment decision criterion does not unfairly favour one group of generators over another. For example, if the decision criterion promoted investment to relieve all transmission constraints, then existing (and new entrant) generators located remotely from load centres could be said to be favoured over potential new entrants close to load centres.

We take "favouring" (or discrimination) to mean any arrangement, not reasonably based on cost, which allows one party to benefit over another. With reference to the example above, regulated transmission could be deemed to favour remote generators if the cost of that transmission together with the cost of remote generators exceeded the cost of generators close to load centres.

In this sense, it is seen that competitive neutrality is an aspect of efficiency, since discrimination will lead to inefficient outcomes. Efficiency is considered in more detail below.

3.1.2. Transmission Competition

There is also a view that transmission services are competitive in the sense that transmission asset ownership is contestable, and that individual transmission investment proposals compete with other distinct proposals. Although the reference to competition in clause 1.3 of the code does not directly mean competition in a market for the provision of transmission services, we believe this view does have relevance.

The list of objectives in clause 6.2.2 of the Code refers to the potential for competition in the provision of transmission services:

> (h) promotion of competition in upstream and downstream markets and promotion of competition in the provision of *network services* where economically feasible;

Also, clause 6.2.3 describes the following regulatory principles:

> (a) Concerns over monopoly pricing in respect of the *transmission network* will, wherever possible and practicable, be addressed through the introduction of competition in the provision of *transmission services*.
>
> (c) The *ACCC* is responsible for determining whether sufficient competition exists to warrant the application of a regulatory approach which is more "light-handed" than *revenue capping*, and if so, the form of that regulation.

In the context of this review, there may be a concern that the decision criterion could discriminate in favour of regulated transmission elements to the disadvantage of unregulated elements or options: in particular non-regulated interconnectors.

We note Boral Energy's concern that existing TNSPs with a large established customer base have a competitive advantage over new entrant TNSPs. As discussed elsewhere in this report, we believe that such competitive neutrality concerns can be handled through the regulators' assessments and allocations of risk through their choice of a commercial discount rate, use of a regulatory WACC and optimisation of asset values.

Nevertheless, defining and testing neutrality between regulated and non-regulated interconnectors is problematic. To make the analogy with neutrality in generation, there would be clear discrimination if a regulated interconnector proceeds and forecloses a proposed non-regulated interconnector which would have been more efficient (eg on a cost-benefit basis). However, since any interconnector proposer can choose the regulated or non-regulated route, a more likely discrimination example would be: there is clear discrimination if the proposer chooses the regulated route when the non-regulated route would have been more efficient. But, what does "efficiency" mean, when the augmentation is the same in each case? Is it that the interconnector can operate more efficiently being non-regulated: for example by having more flexibility in selling its transmission capacity into the market? Or is the non-regulated option more efficient *per se*? Does this mean that, from a cost-benefit point of view, the regulated option should be "*discriminated*" against?

We have taken the view that, since a non-regulated interconnector appears to the market essentially as a generator in one region and a Customer in another region then the neutrality question really reverts to ensuring competitive neutrality between generation options, as discussed above. The more general question - of the theoretical pros and cons between regulation and competition - is beyond the scope of this report, although some of the theoretical considerations are discussed in Appendix 2.

3.2. Economic Efficiency

Economic efficiency does not appear explicitly as an objective for the Code in chapter 1, although it is mentioned by way of background in clause 1.2.1 (d):

> Development of a *national grid* and a national Code of Conduct, overseen by a national regulator such as the *ACCC* (leading to enhanced competition and efficiency within States and Territories as well as between jurisdictions)

Efficiency is given more emphasis in chapter 6, particularly in clause 6.2.2 which sets out objectives for the transmission revenue regulatory regime to be administered by the ACCC. The regime must seek to achieve the following outcomes (not all of which are listed here):

> (a) an efficient and cost-effective regulatory environment;

(d) an environment which fosters an efficient level of investment within the *transmission* sector, and upstream and downstream of the *transmission* sector;

(f) an environment which fosters efficient use of existing infrastructure;

Because the regulated transmission augmentation decision is likely to involve a cost-benefit analysis (of some sort) it is important to review the economic foundations for such analysis. The following sub-sections describe some of the relevant economic issues.

3.2.1. Pareto Improvements and Potential Pareto Improvements

Public policy decisions often involve a trade-off between economic efficiency and equity concerns. To understand this trade-off, economists use the concept of "Pareto Improvements". A decision or project is a Pareto Improvement when some parties are made better off, and none are made worse off. Few would argue that such a decision or project was efficient, but unfortunately there are very few decisions or projects in the real world which guarantee to leave no party worse off. Because of this, the concept of Pareto Improvement is sometimes extended.

A "Potential Pareto Improvement" is a decision or project for which the dollar-valued gains of those who benefit (winners) exceed the dollar-valued losses of those who are made worse-off (losers). In theory, winners could compensate losers, with the result that none would be worse off. But even if no such compensation occurs in practice, there is a view that such decisions or projects are also economically efficient.

This gives rise to a decision-principle of maximising net benefit, which generally means identifying and undertaking the project which represents the greatest Potential Pareto Improvement (among a set of options). In general, this is measured as the net increase in the sum of the consumers' surplus and the producers' surplus. When applied to an economic analysis involving diverse range of consumers, maximising net benefit will generally imply a decision or project under which some individual consumers are winners and some are losers.

3.2.2. Aligning Costs and Benefits

In the context of transmission investment decisions affecting the NEM, there are several reasons why some parties might become winners and others losers. However, one reason which deserves special mention is if the costs of a transmission investment fall on some parties, while the benefits flow to others. Regardless of the equity (or other) implications of such a situation, there are also economic concerns with such non-alignment of costs and benefits. Economic concerns arise from the incentives this non-alignment may place on various market decision-makers.

If costs were not borne by the decision-maker who causes the costs, then a higher level of cost could result over time (than would result if costs were borne by the decision maker). This is sometimes called dynamic inefficiency, and in this case would be due to costs being "external" to the decision. It is relevant in the context of this review because some parties could potentially make decisions (in order to receive benefits) knowing that the costs would fall on others.

To take a hypothetical example, if the regulated investment decision criterion were to promote removal of all transmission constraints, and transmission costs were exclusively allocated to consumers, a new entrant generator could choose to locate in a constrained (exporting) region, confident that the constraint would subsequently be removed at no cost to itself. This outcome would be inefficient if the transmission augmentation together with the new entrant generator cost more than alternative supply or demand options (which would be precluded once the decision were made).

This shows that the existence of the augmentation Test - and the agreed design of that Test - will influence efficiency even before the Test is actually applied, because investors will anticipate the future application of the Test and its impact on their business. In effect, the Test design (coupled with the TUoS cost allocation) is providing locational signals: should the efficiency of these signals be a factor in the Test design?

These signals come from the *interaction* between the augmentation Test and the allocation of augmentation costs. In the above example, the inefficiency arises partly because of the Test criterion (which removes *all* transmission constraints), and partly because of the cost allocation (which allocates no cost to generation). Where inefficiency arises from the interaction between the cost-benefit *analysis* and the cost-benefit *allocation*, we believe that the inefficiency is only relevant to the Test design if it is best addressed through modifying the Test design. So, in the above example, the over-building of transmission might be a matter for the Test design, whereas the correct allocation of costs would be a matter for TUoS design.

3.3. Practicability and Simplicity

This criterion reflects the merit of having a decision criterion which is simple to understand and administer. Although we found no references in the Code to support such an objective, we believe it has considerable merit.

A decision criterion which was unnecessarily complex would be likely to suffer from interpretation inconsistencies and would likely add cost at all stages of the decision process - including formal review.

3.4. Regulatory Certainty

Chapter 6 of the Code expresses a desire for reasonable regulatory certainty. Clause 6.2.2 contains the following objective:

> (j) reasonable certainty and consistency over time of the outcomes of regulatory processes, recognising the adaptive capacities of *Code Participants* in the provision and use of *transmission network* assets;

A simple and straight forward decision criterion would probably provide more certainty for those proposing investments and/or applying for regulated status than a complex one. However, even if simplicity were unobtainable, it is desirable that the decision criterion removes as much uncertainty as possible from the decision process. It should be noted that the main impact of any uncertainty is on non-regulated alternatives rather than the regulated augmentation itself. After all, if the proposed augmentation fails the Test, all the proponent has lost is the time and cost in putting the proposal forward, whereas the impact on a local generator (say) of a proposal failing or passing the Test could be substantial. Increased risk will deter investors in generation and other non-regulated alternatives to regulated augmentation.

However, we also believe that the chapter 5 decision test should not unreasonably constrain the ACCC from exercising regulatory discretion. Relevant to this last point, clause 6.2.2 of the Code contains the following objective:

> (k) reasonable and well defined regulatory discretion which permits an acceptable balancing of the interests of *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate), *Transmission Network Users* and the public interest as required of the *ACCC* under the provisions of Part IIIA of the Trade Practices Act.

4. Designing a benefits test

4.1. Whose benefits count ?

The first issue to address in designing an augmentation test is whose benefits (and costs) qualify for inclusion within the overall cost-benefit analysis. In part this relates to clarifying the semantic differences that have arisen between code definitions of customers and generally accepted understanding of consumers.

4.1.1. Customer Benefit

The current Code generally refers to *Customer* benefit in relation to augmentation. The italicisation indicates that the defined Code meaning of "*Customer*" should be used: this meaning is actually a wholesale customer - ie a party who purchases power from the spot market itself. This will generally be a retailer, although it can also be an end consumer purchasing power from the spot market for their own needs.

In our discussions with stakeholders, we have found nobody who believes that limiting the analysis to wholesale customer benefit is appropriate. It is also widely believed that this was not the intention of the Code drafters. It has been suggested that *Customer* initially referred to both wholesale and retail customers and when this definition was changed the implication for the augmentation provisions was not realised.

In the SANI review, NEMMCO chose to use a wider interpretation of "Customer": ie to include both wholesale customers (ie retailers) and retail customers (ie consumers). This definition of "Customer" will be used in this report[14]. Aggregating retailer and consumer benefits together has the advantage that - to a first order approximation - the test does not need to assess the extent to which lower wholesale electricity prices are passed through to consumers as lower retail prices[15].

The prospect of using Customer benefit in the chapter 5 decision criterion (hereafter referred to as "the augmentation Test" or just "the Test") has raised two issues of concern. Firstly, whether the measure is an appropriate one that will lead to economic outcomes and, secondly, whether future Customer benefit can in fact be estimated in any meaningful way (and, therefore, whether such a Test can be practically applied).

The measurement problem is in estimating how much of the overall economic benefits associated with an augmentation will be passed through to Customers in the form of lower wholesale prices[16] or greater reliability. For example, a \$10m augmentation may lead to a \$30m reduction in generation costs, but what if only \$5m of this is passed through to Customers as lower prices, with the remaining \$25m increasing generator

[14] We now have the terms "customer" (meaning a retail customer), "*Customer [italics]*" (meaning a wholesale customer) and "Customer [no italics]" (meaning both wholesale and retail customers) all being used.

[15] It is generally assumed that - once the retail market is fully deregulated - competition will prevent retailers from capturing a significant proportion of the benefits

[16] "wholesale prices" means the price that retailers buy power from generators: this may be spot prices or contract prices and, indeed, will generally be a combination of these

profits? Would this pass the benefits test? And is there an objective process for deciding that benefits passed through will be only $5m, rather than $25m (say)?

For some parties, it is sufficient that overall benefits can be measured, with the assumption that this will be passed on to Customers through competition in generation[17]. However, NEMMCO - in its SANI determination - felt unable to assume this and therefore found the Customer benefit test very difficult to apply, because of the measurement problem. We agree that this measurement problem is real, for even if it is assumed that competition does eventually drive the benefits through to Customers, the timing of this pass-through is critical to the Test[18] (since this is assumed to measure benefits on an NPV basis). We regard this as a substantial disadvantage to using Customer benefits as the test criterion.

4.1.2. Public Benefit

Public benefit is a wider measurement of net benefit which avoids some of the problems associated with measuring Customer benefit. Because public benefit looks at benefits to **everybody** resulting from an augmentation, the impact on wholesale prices has only a second order impact on net benefit. Primarily, changes in wholesale prices reflect a wealth transfer between sectors in the market: for example between generators and Customers, or between different regions. They do not affect net public benefit, except to the extent that prices are the means by which efficient market outcomes are effected[19].

A public benefit test would capture benefits accruing to generators. It could also measure benefit to parties up and down the value chain: for example fuel suppliers (upstream) and consumers of manufactured goods (downstream). It could also measure those incidentally affected by changes in the electricity market: for example, shareholders, taxpayers and employees in related industries.

As discussed in section 3.1.2, maximising net public benefit is equivalent to choosing the most efficient option (in the sense of a Potential Pareto Improvement). However, casting the benefit net too widely will create new measurement problems. How are indirect benefits identified and estimated, particularly those two or three steps removed from the market? Conventionally, in a central planning environment, planners would undertake "least-cost planning" which would typically consider costs associated with generation and transmission, and the opportunity costs associated with unserved load (whether this load was voluntarily managed or involuntarily disconnected). Limiting the scope in this way - ie to generators and Customers - seems reasonable so long as the transfer prices at the boundary of this scope - input fuel costs and consumer opportunity costs - can be accurately estimated and modelled.

[17] And, furthermore, if this benefit is not going to be passed on, this implies excess generator market power which should be dealt with through another forum

[18] Below we suggest that one way to deal with measurement uncertainties is to look at several scenarios. For example, one scenario could assumed a SRMC-reflective bidding strategy whilst another could apply bidding strategies to achieve LRMC-based spot prices. The problem is that the customer benefit differences between these scenarios will be large and it is entirely unclear the relative weight each should be given in the final decision.

[19] For example, monopolistically high prices may give rise to inefficiently low consumption of electricity.

4.1.3. TUoS Incidence

An alternative approach to casting the benefits net is to look at the sectors that are paying for the augmentation. Costs of augmentation will be recovered through Transmission Use of System (TUoS) Charges levied by the relevant TNSP. Under this approach, benefits will be included in the Test only for those sectors whose TUoS charges will increase as a result of the augmentation.

This approach could be justified from an equity stand-point. Why should somebody be required to pay for an augmentation that they receive no benefit from? However, equity is not a specific NEM objective and we do not consider it to be an appropriate objective for the Test[20].

There are also efficiency considerations, as discussed in section 3.1.2. If somebody knows that they stand to receive benefits from regulated augmentation without paying for that augmentation, this could lead to inefficient investment decisions (eg location of new loads or generators).

Dynamic inefficiency would be minimised if costs and benefits were aligned at the point of every decision made in the market (including transmission investment decisions). However, the possibility that regulated transmission costs and benefits may be difficult to align (through TUoS charges), should not provide a reason to distort future regulated transmission investment decisions.

In other words, defining the Test does not seem to be an appropriate point to address potential inefficiencies, since restricting the benefits to those paying TUoS is likely to introduce further inefficiency.

There is a more general consideration which has been raised with us. Given that TUoS charges are currently being reviewed, is it possible to design an appropriate Test before knowing the outcome of the TUoS review? This issue is considered further in section 7.

Some parties have suggested that the Code currently refers to "Customer benefits" precisely because, under current rules, it is Customers who end up paying TUoS. However, if this were the intention, it would seem likely that the Code would be more explicit in linking the two. Furthermore, the current connection is not as strong as this because, under CRNP only certain Customers will pay for an augmentation (based on geographical location) whereas the benefits of all Customers is captured for the existing benefits Test.

Finally, the assessment of who actually bears the cost of TUoS is complicated by the same pass-through considerations that create difficulties in assessing who benefits. Depending on supply and demand elasticity, a TUoS charge on Customers may be borne to some extent by generators and, equally, a TUoS charge on generators may be passed through to Customers.

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[20] However, the Code does provide that , for intra-regional augmentation, any person who will be impacted by materially increased TUoS has the right to dispute the augmentation proposal. This may give some protection against "inequitable" augmentations.

4.1.4. Conclusions

We have identified two distinct arguments for restricting the Test to assessing Customer benefits only

1. The first view is that net overall benefits will always be passed through to customers anyway (assuming there is sufficient competition) in which case public benefit and customer benefit are largely interchangeable terms. According to this view, references to Customer benefit in the current Code draft are entirely adequate. However, we believe the assumption of adequate competition might sometimes be contentious, and therefore a less ambiguous expression of the Test is required.

2. The second argument is based on the belief that it is Customers who pay TUoS charges. This being the case, it would be inequitable and inefficient for customers to pay for transmission augmentations which did not directly benefit them (as a group). We agree that the Test may potentially interact with the cost allocation to provide inefficient incentives in the market. However, we believe that any equity or efficiency considerations concerning who pays TUoS are better dealt with under the TUoS review (which is in progress), rather than through the Test.

We believe the Test should not focus purely on the direct benefits to customers, but it may be that the term "public benefit" casts the net too widely (especially if costs and benefits outside of the electricity market were considered). We think that a net which captures benefits in the value chain from generators to consumers is the most appropriate solution. This will lead to the most efficient and practical method and meets the important objective of competitive neutrality. We call this a "market benefit" test, where the word "market" essentially means the consumers and producers of electrical energy, and includes the consumption and provision of network services. Section 4.2 defines in greater detail what would be included in the scope of a "market benefit" test.

In terms of the evaluation criteria discussed in section 3, economic efficiency is the primary concern here. What we mean by net benefit to customers and generators is intended to have the same meaning (in the language of economics) as the change in the sum of consumer surplus and producer surplus. The test should not be dependent on how that surplus may ultimately be shared between generators and consumers (and/or with TNSPs and retailers).

4.2. Which types of benefits are included?

If the benefits net covers Customers and generators, what types of benefits accruing to these groups should be included within the cost-benefit analysis? Benefit types likely to be impacted by augmentation are discussed below.

4.2.1. Market Payments

Since the spot market balances[21], spot prices have no overall, direct impact on the total benefits accruing to generators and Customers. Similarly, payments under wholesale

[21] Allowing for the fact that the Settlement surplus is returned to market participants through reduced TUoS charges.

contracts will be between retailer and generator[22], and so will not figure in calculation of total benefits.

This is not to say that wholesale prices are irrelevant to the benefit analysis. Market outcomes will have an important second order effect on benefits, since they will determine how the market operates and therefore how benefits accrue. This issue is discussed in section 4.3.2 below.

4.2.2. Generation Costs (Energy)

Impact on generation costs is likely to be a major benefit associated with augmentation. Costs should include both fixed costs (eg capital costs, fixed O&M etc) and variable costs (fuel costs, variable O&M etc).

Given that generation cost reductions will be a major reason for augmentation, these costs need to be fully captured.

4.2.3. Ancillary Services Costs

Reduction in ancillary services costs - particularly spinning reserve - can be a major benefit of augmentation, particularly where two previously unconnected or weakly-connected regions are interconnected. Benefits arise from both a reduction in the total level of reserve that must be carried across the market (ie reserve sharing) and the ability to procure that reserve from a cheaper source. On the other hand, an augmented interconnector may lead to increased spinning reserve costs, if a forced outage of that interconnector is a contingency that needs to be covered by spinning reserve.

Because of the likely significance of ancillary service costs in assessing augmentation benefits, it is vital that these are captured and measured in the benefits analysis.

4.2.4. Transmission Costs

The major transmission cost will be the proposed augmentation itself. However, there may be other augmentation required as a result of the proposal, and these costs also need to be captured. On the other hand, the augmentation may lead to benefits in respect of the deferral or cancellation of other augmentation that would otherwise be required. For example, a new interconnector may serve a growing sub-regional load which would otherwise have required some intra-regional augmentation.

4.2.5. Consumer Costs/Benefits

So long as consumers continue to receive electricity supply in the same way as without the augmentation, the net benefit of the augmentation will simply be the change in wholesale price which - as noted above - exactly offsets an equivalent benefit to generators and can therefore be discounted. However, if a consumer's supply changes, other net benefits will accrue. If a consumer obtains a reduced supply, either voluntarily - as a load management response to higher prices - or involuntarily - due to load disconnection by the market operator - they will lose the benefits previously obtained from that electricity supply and may incur costs associated with the loss of supply.

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[22] Where payments go outside - eg to fuel suppliers - assumptions will need to be made: eg in estimating input fuel costs.

Conventionally, in a least cost planning approach, load management has been modelled by an equivalent level of "pseudo-generation". For example, if a consumer is prepared to reduce demand by 1MW if prices rise above $100/MWh, this can be modelled by including a pseudo-generator of this price and quantity among the generation options. Similarly, disconnected load is modelled by applying a Value of Lost Load (VoLL) to the unserved energy (USE). This is discussed in more detail below.

Therefore, consumer costs and benefits can and should be modelled in the Test (otherwise, the cheapest approach would be simply to not supply electricity!). However, it may be more problematic to estimate what these benefits are.

4.2.6. Security and Reliability

The Code deals with system security and system reliability separately - although they may seem like two aspects of the same thing. A secure system is one in which the impact of contingencies (for example, a generation outage) is manageable and containable. It does not necessarily imply that load is being supplied reliably; a system in which not all load is being supplied can still be secure.

NEMMCO is responsible for managing system security through applying constraints on generation and transmission flows. An augmentation will not by itself improve system security, since NEMMCO will operate to the same security standards with or without the augmentation. However, the cost of maintaining that security may change, for example through relieving the degree of transmission constraints, or decreasing the cost of ancillary services, required to maintain security.

System reliability is a measure of how often load needs to be shed by NEMMCO to preserve system security. The Reliability Panel - which reports to NECA - is responsible for setting reliability standards. We understand that the current standard is that, on a regional average, no more than 0.002% of load is disconnected.

There are two ways of measuring the reliability benefits provided by an augmentation. The first is to measure the cost of USE with and without the interconnector, in which case the appropriate level of VoLL must be chosen. A figure of $5000/MWh is used in the spot market to cap spot prices. This is the maximum benefit that a generator can obtain through the spot market for enhancing supply reliability. However, we have been told by various stakeholders that a VoLL of $5000/MWh is inconsistent with maintaining the reliability standards noted above and that a VoLL of around $25000/MWh (or even higher) would be necessary to provide sufficient market signals at peak to achieve the reliability standard[23].

The second way of measuring reliability benefits is to consider the cost of alternatives required to maintain the same level of reliability; or, more specifically, to look at how much cheaper (or more expensive) it is to maintain reliability at the agreed standard with the augmentation than without the augmentation: in other words, to test the augmentation proposal for *cost-effectiveness* in achieving reliability rather than its *cost-benefit* in

[23] The increase reliability from a higher VoLL level may come from both increased load management at these prices and new or existing peaking plant which may not other wise be viable with a lower VoLL.

reducing USE. However, given that this analysis can be achieved (and probably would be achieved in a modelling sense) through varying the level of VoLL until the reliability standard is achieved, this approach is really no different to the VoLL approach discussed above.[24]

The key issue, therefore, is choosing the appropriate level of VoLL. Should it be consistent with the market VoLL, or the VoLL required to maintain reliability. Given that VoLL (and other mechanisms for achieving reliability) is currently being addressed by a NECA review[25], it is inappropriate to be definitive at this point: this is discussed further in Section 7.3. Until the NECA review is complete, we would make the following recommendations:

- that VoLL should be applied consistently between generation, demand and transmission in all benefits analysis and;
- scenarios using both a market-based VoLL ($5000/MWh) and a reliability-based VoLL (eg $25000) should be assessed and the resulting net benefits should be factored into the ultimate decision on augmentation.

4.2.7. Externalities

A conventional public benefit test would include some or all externalities: ie benefits that are not explicitly costed or priced within the electricity market itself. An example of externalities associated with an augmentation would be the benefits of reduced power station emissions - for example carbon dioxide - due to fuel substitution. Should such external benefits - where they can be properly quantified - be included within the Test?

Submissions were somewhat polarised on this issue. Some argue for inclusion of externalities largely on the grounds that approval of regulated transmission augmentation provides an opportunity for government to correct or ameliorate (albeit indirectly) various forms of electricity market failure. Specifically, if the market fails to adequately address external costs such as those associated with greenhouse gas emissions, then at least transmission augmentation decisions should be made to address them.

A contrary argument is that if government has concerns about externalities, more direct intervention would probably be more effective (eg using a carbon tax to address greenhouse emission concerns). This approach would also ensure that an investment criterion for the electricity industry, and administered by NEMMCO, was not seen to be the mechanism for determining and achieving social outcomes which lie outside of the electricity industry.

To support the inclusion of externalities, some note that the ACCC (which is the transmission regulator) is required to consider the public interest under the Trade

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[24] Some alternatives may give a higher level of reliability than the standard. Under the cost-effectiveness approach they would be given no credit for this, whereas under the VoLL approach they would be credited at VoLL*USE for the difference. However, even with a VoLL of $25000/MWh, reduction of USE below the 0.002% is unlikely to create significant net benefits.

[25] The Review of Capacity Mechanisms

Practices Act (TPA), which specifically includes consideration of intangibles relating to social equity, health and safety, and the environment.

However, we believe it is useful to distinguish two roles performed by the ACCC in relation to the Code. In one role it is the body which authorises the Code under the TPA, which is distinct from its role as transmission regulator pursuant to chapter 6 of the Code. In its first role, the ACCC must consider the public good at a very wide level, including such intangibles as health and safety, and social equity.

In its second role, as transmission regulator, the need to satisfy the objective of competitive neutrality (which is explicit in the Code) leads one to conclude that intangibles such as social equity should not be considered (as relevant aspects of public benefit). Neither should they be considered by TNSPs and NEMMCO in their roles under Chapter 5 of the Code.

From the point of view of competitive neutrality, costs and benefits should be credited to an augmentation where similar costs and benefits would accrue to alternatives such as local generation. For example, benefits from fuel substitution could come from an augmentation allowing remote generation to displace local generation; they could equally come from local "cleaner" generation displacing the existing local generation. However, to the extent that current and/or future environmental benefits are not priced into the market, they would not enter the "cleaner" generator's investment decision-making.

Note that our definition of externalities is strict. The regulatory test should include those environmental and health and safety considerations which are already the subject of government laws and regulations. Also, some environmental considerations are already "internalised" through the process of gaining planning approval for augmentations and generation[26] and these will automatically be included by the proponent as part of the development cost.

Similarly, if there were some likelihood that factors which are currently regarded as externalities might become "internalised" in the future, then they should also be incorporated into the sensitivity analysis. For example, if it were widely believed that carbon taxes or greenhouse emissions trading mechanisms might be introduced within 10 years, then scenarios which reflected these features might be developed (as part of a sensitivity analysis) and could well influence the final outcome.

It is possible that, where there are external benefits, parties would be prepared to pay for these outside the NEM mechanisms. For example, government might conceivably provide some funding towards an interconnector for the environmental or job creation benefits it would provide, or a telecom provider might pay to use the interconnector for winding optic fibre along. In these cases, the external revenue could be discounted from the cost which is applied in the Test. For example, a $500m interconnector that attracted $100m of external revenues could apply to be tested against a capex cost of $400m.

[26] Developers are required to prepare an Environmental Impact Statement which assesses the environmental costs and benefits and measures for mitigating them.

We note that there are possible regulatory concerns here[27] but these should be addressed through the ACCC's valuation process rather than through the Test.

Some have commented [London Economics] that the funding of external benefits is irrelevant to an assessment of public benefit, claiming it is sufficient to quantify the external benefits without identifying if or how they might be funded. However, in our view, a transmission investment should not be deemed regulated merely on the grounds that it provides (say) telecommunications benefits, without the investment cost being shared with the consumers of those other services. The regulatory test should not be a mechanism whereby electricity consumers are expected to subsidise telecommunication services, government employment programmes, or other benefits external to the NEM. This further reinforces our view that the test should properly be described as a "market benefit" test, as distinct from "public benefit".

4.2.8 Competition Benefits

Some submissions point out that transmission facilitates competition between generation, and claim that the benefits of greater competition should therefore be counted in the cost-benefit analysis of a proposed augmentation. In other words, transmission augmentation can and should be used as an instrument to ameliorate abuses of monopoly power in the generation market.

From an economic point of view, the presence of generator market power or monopoly pricing implies levels of consumption lower than would be economically optimal (based on the economic cost of supply). The amount of inefficiency may be called dead-weight loss.

Under an analysis which counted consumer and producer surplus, a transmission augmentation could pass the test if it served to increase competition to the extent that the reduction in dead-weight loss exceeded the augmentation cost (on an NPV basis). (On the other hand, if only consumer surplus were counted in the analysis, a transmission augmentation would pass the test more easily because the loss of generator monopoly profit would be ignored.)

There are of course difficulties associated with identifying monopoly pricing and measuring dead-weight losses (just as there are with measuring other economic costs). Even if these costs could be measured with confidence, the question must be asked - is transmission augmentation the best way to minimise dead-weight losses associated with abuse of market power?

The NEM was established on the basis of disaggregating the generators to create a contestable market, where entry by new generators places a cap on the ability of incumbent generators from taking advantage of a tight supply/demand situation. To the extent that the existing market structure may be unable to constrain the abuse of any monopoly power, there are other avenues for the control of monopoly power - through market reform, or more directly through action by the ACCC under the TPA. If however,

[27] The ACCC would need to confirm that all external revenues were declared accurately so that the "net cost" of the augmentation was at the appropriate level.

the ACCC were to find insufficient evidence of market power abuse, it is unlikely that a regulated transmission augmentation would be justifiable on that basis (alone) either.

It is possible that an assessment of increased competition might help to tip the balance of a proposal which had other tangible (but barely sufficient) economic benefits. However, it is unlikely that the beneficial effects of increased competition due to transmission augmentation could be sufficiently well quantified for the augmentation to proceed on this basis alone.

4.2.9. Conclusions

The benefits that are included in the tests should be directly associated with generation costs and consumers' costs associated with not receiving supply - where this supply changes with or without the augmentation. System security is a standard that is applied with or without augmentation and so does not figure as a direct benefit. However, there may be benefits associated with providing system security at a lower cost: this might be through a change in dispatch constraints or by the augmentation providing ancillary services at a cheaper price than would otherwise be available. Reliability benefits can be explicitly measured through the use of a VoLL for unserved energy. The appropriate level of VoLL to use is unclear at present and is dependent on the outcome of the Capacity Review.

Any types of costs and benefits which cannot be captured by augmentation alternatives, such as local generation, should not be counted in the analysis.

4.3. How are benefits measured?

4.3.1. Cost-based Modelling

Benefits from an augmentation will be measured by estimating the change in costs and benefits accruing to generators and Customers in the categories described in the above section. A Net Present Value (NPV) of the net benefits over the life of the augmentation asset will be calculated by applying a discount rate[28] to the benefit stream.

Conventionally, net benefit would be measured by comparing the differences in total costs with and without the augmentation. However, it would be mistaken to treat the "without" case as a "do nothing" option. A competitive market will never stand still and, with or without the augmentation, market participants will constantly be reacting to changes in the market such as load growth, plant ageing, new technology and new fuel sources. Therefore, the net benefit has to be measured by forecasting how the energy market will develop with and without the augmentation and looking at the difference in overall costs and benefits between the "with" and "without" scenarios.

4.3.2. Expansion Scenarios

The most difficult - and contentious - part of developing future market scenarios will be in making "expansion" assumptions: ie the building of new generating or transmission

[28] Discussed in section 4.3.4

plant in response to market signals. Short-run modelling of the market is more straightforward, based on merit-order dispatch of generation against likely dispatch constraints.

Expansion scenarios should include three types of new projects: committed projects; anticipated projects; and modelled projects. These are described below.

Committed projects are those which are already underway at the time of the Test, and likely to be commissioned within the next few years. These should be straightforward to identify in principle, although there may need to be some guidelines which describe what evidence is required before the project can be treated as committed.

Anticipated projects are those where project planning is at an advanced stage, but there is still a possibility that the project may not go ahead. They are likely to be commissioned between 2 and 5 years out. It will necessarily be a subjective assessment by the scenario developers as to whether to include such a project. On the one hand it would be inappropriate to approve an augmentation when a cheaper alternative looks realistic. On the other hand, augmentation should not be able to be blocked by putting up "paper projects" which look cheaper but have no realistic prospect of being developed. Again, appropriate guidelines would provide for some objectivity in identifying anticipated projects.

Modelled projects are those which are in the mind of the planner rather than any prospective developers. They are necessary for the benefit modelling, as the timescale of the study means that projects must be included which may not be realised for 10 years or more - well beyond the horizon of any specific investment plans. Modelled projects will be based on generic generation costs and technologies, and would be commissioned (in terms of the analysis) not less than 6 years out.

Some have argued that only committed projects should be considered, because otherwise an augmentation might otherwise be effectively blocked or delayed by fictitious projects which never eventuate. Although this is a risk, not to include such projects would, in our view, result in an even more biased test; given that the benefits accruing from a transmission augmentation are to be measured over many years, it is unreasonable to assume a state of no change on the supply side of the market during that time. The market will not remain static, and the analysis must attempt to model how it develops even though there are many uncertainties. Few investors would enter a market assuming no further entry by competitors.

The concerns regarding unrealistic or fictitious projects (and unrealistic demand forecasts) are best addressed through complete transparency of all aspects of the modelling and rigorous debate during the public consultation.

Two approaches can be taken to developing modelled projects within expansion scenarios, which we will call "least-cost expansion" and "market-driven expansion". The least-cost expansion approach would include new modelled projects based on a least-cost planning approach akin to conventional central planning: ie the schemes would be included where the NPV[29] of the benefits - such as fuel substitution and reliability

[29] Using an appropriate discount rate - see section 4.3.4.

increases - exceeded the costs. The market-driven expansion approach would mimic market processes by modelling spot price trends based on existing generation and demand and include new generation on the same basis as a private developer would: ie where the NPV of spot price revenue exceeded the NPV of generation costs.

The two approaches should give broadly similar outcomes, assuming the same inputs. The difference is that the least-cost expansion approach should identify the maximum benefit that *can* be delivered by the market, whereas the market-driven expansion approach measures the benefit that *will* be delivered by the market[30]. If an efficient market is assumed, the two are the same. On the other hand, if a less-than-perfectly-efficient market is assumed, then the market-driven expansion may be able to model the augmentation benefits associated with increased market efficiency: eg through a reduction in market power[31].

4.3.3. Input Sensitivities

Inevitably there is a large amount of uncertainty on the input assumptions for a planning scenario: such as load growth, and generation capital and fuel costs. To reflect this uncertainty, benefits should be tested over a range of scenarios, testing for sensitivity (by small changes in the inputs) and stress (by large changes in the inputs).

4.3.4. Discount Rate

We propose that the net present value (NPV) of benefits is measured over the lifetime of the augmentation. This section discusses the discount rate which should be used to calculate NPVs, from a theoretical and practical point of view.

Potentially, three different discount rates could be used in the modelling:

- a WACC to apply to the augmentation cost to estimate TUoS charges[32]
- a discount rate applied to identify the entry time of new generation;
- an overall discount rate to apply to calculate NPVs of costs and benefits.

Philosophically, there are two approaches to setting discount rates. To the extent that the analysis is a public benefit analysis, a public sector discount rate could be used. On the other hand, since the scenarios are aiming to measure benefits in a market environment, it can be argued that commercial discount rates should be used[33].

[30] Assuming that the market actual behaves as modelled.
[31] Note that market efficiency will only have a second-order impact on realised benefits, whereas it will have a first-order impact (through price changes) on allocation of benefits.
[32] The cost of the augmentation can be modelled in two ways - either as a "Year 0" capital cost, or as annual TUoS charges over the life of the asset. These two approaches will give different outcomes if the discount rate used in the overall NPV calculation is different to the WACC used in setting TUoS revenue.
[33] In practice the outcomes from using public or commercial discount rates may not be as different as they may first appear to be: it is a common mistake in public benefit analysis to underestimate the amount of uncertainty, particularly in the benefits stream, and the result of explicitly factoring this into the analysis and decision process may well give a similar outcome to the use of a higher discount rate.

Both approaches can create difficulties. Expansion scenarios (specifically, modelled generation) will be unrealistic if they assume that generators make investments on the basis of a public sector return on capital. On the other hand, if commercial discount rates are applied, TUoS costs modelled in the analysis will be higher than actual TUoS charges.

One option would be to use low discount rates for the transmission related benefits and commercial discount rates for generation. However, this would create a significant bias in favour of transmission, which is inconsistent with the "neutrality" objective discussed earlier.

We believe this paradox arises because the transmission owner is treated as funding the augmentation. In reality, it is the TUoS payers who fund the augmentation[34] and it is they who bear the commercial risk of the anticipated benefits not eventuating[35]. Since many of these are commercial organisations, a commercial discount rate *does* seem appropriate[36]. Using such a rate seems to address a common concern noted to us that "the central planner does not bear the risk of the benefits not eventuating".

Therefore, we recommend that, for the purposes of calculating an NPV of anticipated benefits, a commercial discount rate should be used. This will remove a potential source of bias between generation and transmission options. However, this approach does not affect the WACC that is used for the purposes of setting allowable revenue on the augmentation assets once they are built. The WACC should be based on the amount of risk that the TNSP faces once the augmentation is approved as a regulated asset.

There is some discussion in submissions of use of the discount rate to address forecasting uncertainties. This raises the question of why the "opportunity cost of capital" (and consequently commercial hurdle rates of return) differ from the social rate of time preference - a question which has been debated in economic literature without firm resolution. It also raises the question of how uncertainty is accounted for in the "commercial" analyses that we are attempting to mimic to achieve neutrality. Our observation is that, whilst the textbook approach is to adjust the cashflows for uncertainty, not the discount rate, in practice raising the discount rate is often used as a proxy adjustment for greater uncertainty.

These are difficult areas, not fully resolved either academically or in practice. As a practical solution we suggest that the economic cost/benefit uncertainty associated with transmission investments is not sufficiently dissimilar to the alternatives to warrant using a different WACC; and the specific uncertainties that might distinguish between the options are better modelled using different scenarios (ie with different cashflows).

[34] The TNSP effectively provides the TUoS payers with a capital loan, which is underwritten by guaranteed TUoS payments.
[35] This assumes no subsequent optimisation. If there is re-optimisation, the risk of benefits not eventuating is passed from the TUoS payer to the transmission owner, who will as a result seek a higher WACC.
[36] This commercial rate is only applied to the benefits analysis. We are not recommending - and would not recommend - that this same rate should be used as the WACC for setting actual TUoS revenue.

4.3.5. Conclusions

To conclude, benefits should be measured by looking at total benefits (as defined in section 4.2) with and without the augmentation across a range of scenarios using different input assumptions and deriving expansion scenarios from both least-cost expansion and market-driven expansion models.

Most submissions support our proposal that a single discount rate should be used and that this should be a "commercial" discount rate as opposed to a (presumably lower) social rate of time preference. Support for this was typically based on the importance of neutrality between the regulated and unregulated options.

4.4. How is the Decision made?

4.4.1. Benefit Maximisation

The current Code requires that benefits should be "maximised" by the augmentation for it to be approved. What does this maximisation mean, and why is it necessary?

As noted above, net benefit cannot be calculated by comparing costs and benefits associated with the augmentation with a "do nothing" option. The market will never "do nothing", and to assume that it might gives an unrealistic picture of what benefits may be provided by the augmentation.

The least-cost expansion approach described above suggests one approach to defining benefit maximisation. The question "is benefit maximised?" could be re-phrased: "in a central planning environment, would my expansion plan include this augmentation[37]?" If an alternative looks cheaper (eg local generation) then that option should be chosen.

However, central planning no longer exists, and nobody can require that the generation is built[38], so there is a risk that the generation (or other option) does not get built. This is where the market-driven expansion approach is useful, as it will give a guide as to which market behaviours would lead to the generation being built. If the required behaviour is unlikely, the augmentation could be regarded as maximising benefit, even if the generation alternative is "theoretically" cheaper.

If the generation alternative cannot be guaranteed, the possibility of it *not* going ahead should be considered as a separate scenario: for example, the generation may only be $10m cheaper than the augmentation, but the consequences of neither going ahead may create a risk of $100m in additional costs (eg through loss of reliability).

[37] And also have it introduced in the same year as proposed by the proponent. Timing issues are discussed in the next section.

[38] It is for this reason that a Tender approach is inappropriate, at least for inter-regional augmentation, since nobody can require that the winner of the tender builds their proposed project. For intra-regional augmentation, the NSP may contract with generation or demand if they can provide a cheaper alternative to augmentation, with the contract costs being treated as transmission costs for the purposes of revenue regulation.

Therefore, "maximise" cannot and should not be interpreted to mean that the augmentation should minimise costs under all possible scenarios, but it can be appropriately interpreted to mean that the augmentation comes out "best or close to best" under a broad range of realistic scenarios and, on this basis, outscores any of the alternatives.

4.4.2. Timing Issues

One possible outcome of the scenario analysis is the result that, the augmentation maximises benefit, but only if it is built in Year 1 rather than Year 0. Does this mean that the augmentation as proposed (ie in Year 0) fails the test?

Some have suggested that it is a matter for the proponent to "optimise" the timing of their project. However, this pre-supposes that they are properly incentivised to do this. This may not be the case. They will receive the same regulated revenue whatever the total benefits, so long as they pass the test. In other words, they are incentivised to maximise their chances of passing the test, not to maximise the benefit of the proposed augmentation timing. If the benefit analysis does not require optimal timing of the augmentation, the proponent may be encouraged to deliberately bring in the project earlier than optimal in order to forestall alternatives[39].

For this reason, it seems appropriate to consider re-timing the project to increase expected benefits (if necessary). However, if the optimal timing is a year's delay, it could be possible to allow a conditional authorisation, on the basis that the project is delayed for a year, subject to no major alternative expansion projects becoming committed or other material changes occurring in the market in the mean time which were not anticipated in the benefit analysis.

We recognise that determining the optimal commissioning date may not be a straightforward matter. There may be interdependencies with other projects and planned network operations, as well as manufacturing and construction constraints. Nevertheless, the principle remains that the test should confirm that the project timing is optimal.

Also, the developer may choose to commission an augmentation earlier than the optimal date (as confirmed by a cost-benefit analysis). However the value of the augmentation (assuming it passed the test) should not be incorporated into the regulated asset base until the date considered to be optimal; hence the developer would effectively bear the cost of bringing forward the investment.

Another timing consideration is how far ahead of proposed construction the proponent should submit to the Test. A certain amount of time will be required to undertake the Test and the attendant consultation processes and it may also be prudent to allow time for possible appeals or dispute resolution. However, excessive lead time would again create risks that alternatives could be forestalled. This concern may be exacerbated where the lead time to build and commission the augmentation is longer than the lead time required

[39] This pre-supposes that a competitor will not come in with a rival project, identical except for timing differences. However, why should the test analysis not create a "modelled" rival in the same way as it creates other modelled expansion options.

by alternatives[40], so that alternatives may not have reached a "committed" stage. It would be appropriate for these timing issues to be addressed in the Test guidelines.

It has been suggested that there is a "cooling off" period after the completion of the Test and before the augmentation is authorised, to allow alternative projects to be developed and committed. If this period is provided, it should be factored into the Test lead time; it should not be a reason for further delaying the augmentation beyond the proposed timing.

4.4.3. Consultation Process

The preceding sections have indicated that the Testing process can be a complex one in respect of the range of assumptions and scenarios the modelling must use. For this reason, it is essential that the testing process is a very open one, with all stakeholders having an opportunity to provide input and to come to a full understanding of how the benefits have been measured and how a decision has been reached. Specific consultation may be required on:

- identifying committed and anticipated projects
- setting input assumptions such as fuel costs, load growth etc
- modelling market behaviour and considering the realism of expansion scenarios
- understanding how benefits will be allocated (although this is not directly relevant to the test outcome)
- understanding how a decision might be reached.
- responding to a draft decision before a final decision is made

4.4.4. Making the Decision

The process described above makes it very difficult to define a formulaic decision process. For example, a formulaic decision process might prescribe looking at the expected benefit of the augmentation using a weighted average of a range of scenarios. However, this would imply that all the individual scenarios must be defined and weights attached to all of them. Input assumptions must be objectively arrived at through a defined process (eg looking at forward fuel prices based on traded commodity futures) or established by a well-recognised independent party (eg an economic research group).

Even if this were possible in practice, would it be sensible? Suppose a scenario is proposed that is not covered by the detailed decision formula. Should this be ignored; or the decision formula changed? And who is to define and agree the decision formula initially?

It seems more sensible to leave a significant degree of judgement in the definition of the scenarios and how the various scenarios should be weighted and assessed to come up with a final decision. This has implications for the appropriate person or body to make the decision. This is addressed in Section 6 below. However, whilst we believe specifying a single decision criterion would be counterproductive, some guidelines (which could be amended from time to time) would be helpful.

[40] This is likely to be the case where alternatives are demand management or peaking generation

4.4.5. Conclusions

To conclude, the aim of the Test should be that benefits are maximised. In other words, no alternative has been identified (including a re-timing of the proposed augmentation) that would consistently provide greater benefits. However, given that it is extremely unlikely that any proposal would be the best under all possible scenarios, the decision must be made by weighing up the performance of the proposal across the range of scenarios: broadly, "maximise" should be interpreted as being best, or almost best, over a wide range of scenarios.

It would be difficult - and inappropriate - to be totally formulaic about the decision process, and so some degree of judgement must be used. However, an agreed set of guidelines would be helpful in providing more certainty on the outcome.

4.5. Augmentation Context

Section 2.1 described the different routes by which augmentation proposals may be developed and tested under the Code. Should the approach to Testing differ depending on the augmentation context. Specifically:

- should different benefits be included in the Test?
- should specific benefits be measured differently?
- should the Test decision be made differently (Eg should the burden of proof be different)?

4.5.1. Benefits Included

Nothing in Section 4.2, which considered which benefits should be included, was context specific and so we see no reason to capture different benefits, for example, between inter-regional and intra-regional augmentation tests. However, it will certainly be the case that the relative importance of the different benefit categories will differ. For example, it is likely that generation costs and ancillary service costs will be a major consideration for inter-regional augmentations, whereas reliability considerations are likely to feature more strongly in intra-regional augmentations.

In discussing reliability, the reliability standard quoted applies to regions as a whole. It is not necessarily the case that the 0.002% standard should apply to sub-regions. Put another way, it would not necessarily be appropriate to apply a higher level of VoLL when looking at reliability to sub-regions where this would be necessary to achieve the 0.002% reliability standard within this sub-region.

TNSPs have indicated that, where reliability within a sub-region is the issue, they would normally discuss this with local stakeholders to agree reliability requirements (and the appropriate cost-benefit trade off) rather than holding to a fixed standard. This seems a reasonable approach to take.

4.5.2. Measurement of Benefits

Again, nothing in the previous discussion was context specific. However, it may well be the case for some augmentations (particularly intra-regional) that certain benefit categories (or expansion scenarios) can be ignored, a priori, as having no possible impact on total costs. This approach is appropriate, so long as these assumptions are transparent and open to comment from stakeholders. Also, materiality must be considered, with complex and costly analysis being inappropriate for relatively minor augmentations. Perhaps more deterministic planning guidelines could be established by the TNSPs - and approved by the ACCC - for these smaller projects, to simplify the augmentation process.

4.5.3. Burden of Proof

The burden of proof should be judged against the likelihood and impact of making a wrong decision either way: ie the risk of blocking an augmentation and suffering adverse cost versus the risk of approving an augmentation and the benefits not being realised. For intra-regional augmentation it is possible that the potential downside of blocking augmentation (in terms of reliability risks) could be much higher than the downside of approving it (since the augmentation is unlikely to adversely affect the generation market).

On the other hand, for inter-regional augmentation, the downside of blocking augmentation could be lower (than the downside of approving it), if alternative generation were likely to ensure continued regional reliability (even if more expensive than augmentation).

However, submissions have pointed out that these generalities do not always hold and so it does not seem reasonable to simply assume that the relative upside and downside risks are systematically different for inter- and intra-regional augmentations. Therefore we do not recommend that one form of investment approval should enjoy a higher burden of proof than the other.

Another consideration is whether the proponent of the augmentation is the same as the potential owner. For example, in Victoria, VPX would propose intra-regional augmentation (as the local TNSP) but would not be the owner, and therefore would not stand to benefit (in a financial sense) from the augmentation being approved. Should the burden of proof on VPX therefore be lower than for a TNSP who owns transmission assets?

The objective of the Test is to ensure that transmission systems are augmented efficiently and that imposing TUoS charges on market participants is justified by the associated benefits accruing to the market. These efficiency considerations are the same whoever the proponent is. For this reason, we do not consider it appropriate to change the burden of proof.

5. Valuation of Regulated Assets

5.1. Valuation Objectives

5.1.1. Allocating Cost-based risk and Benefit-based risk

Under Chapter 6 of the Code, the allowable TUoS revenue to TNSPs is based on the value of their regulated asset base and the agreed WACC. The Code envisages an initial valuation and then possible subsequent revaluation, based on ODV or other appropriate valuation methodology.

The objective of the valuation and re-valuation processes is to appropriately allocate risks between the TNSP and market participants (ie TUoS payers). There are two types of risk that are addressed by the valuation process:

- that the replacement cost differs from the historical cost;
- that the benefits anticipated to be provided by the augmentation do not eventuate.

Risks associated with the replacement cost are outside the scope of this report[41]. However, risks associated with anticipated benefits not eventuating are highly relevant, since it is these anticipated benefits that are measured by the augmentation Test. These would be covered by the optimisation and economic value tests in an ODV valuation methodology

5.1.2. Risk Allocation Principles

It is not within the scope of this report to consider what is an appropriate allocation of risks. We would simply point out that a TNSP will expect that any higher risk must be compensated through a higher WACC that is paid for by market participants. Therefore, there is a trade-off to be made between the value of placing risk on the TNSP (eg through sharper investment incentives or more efficient TUoS signals) versus the cost in terms of higher WACC and higher TUoS. The basic rule of risk allocation - that it should be allocated to the party that can best manage it - should provide a guide to the appropriate trade-off.

However, this report *will* look at effective mechanisms for allocating the risk and how this relates to the augmentation Test described in the previous section. For an allocation mechanism to be effective, it must be:

- **definite**: any ambiguity or lack of clarity creates additional uncertainty and heightens risks on the TNSP.
- **accurate**: if TNSP revenue is going to be impacted it must be directly related to the benefits not eventuating.

[41] We note however that these risks may well exceed optimisation and economic value-related risks. Treatment of these risks is an issue involving linkages between the specification of the WACC in the revenue requirement formula (particularly the “inflation” component of this), and articulation between asset value adjustments generally and the revenue requirement formula.

Definition is to be provided by the ACCC's SRI which will set out clear principles for valuation and revenue setting. It may be that, on an augmentation-specific basis, further definition could be provided by a more detailed agreement between the ACCC and the relevant TNSP on revenue setting before the augmentation capital is committed.

We will define accuracy according to two principles, which directly link the valuation and revenue setting process to the augmentation Test.

1. If the benefits measured by the augmentation Test eventuate as anticipated, there should be no revenue impact on the TNSP[42];
2. If anticipated benefits do not eventuate, there should be a clear and direct relationship between the loss of benefits and any impact on TNSP revenue.

5.1.3. Risk Allocation Mechanisms

There are two processes through which the ACCC can allocate risk between TNSPs and market participants in respect of an augmentation: setting the initial value[43] of the augmentation-related assets; and subsequent revaluation of these assets at a subsequent regulatory review.

Our risk allocation principles set out above dictate that the initial value for the augmentation should based around the project cost that was used in the Test. Any deviation from this cost would immediately impact on the TNSPs revenue and, assuming the augmentation Test has properly assessed the anticipated benefits to be provided by the augmentation, there is no reason - at this point - to suppose that these benefits will not eventuate. The process of ensuring that the initial value is consistent with the Test is set out in section 5.2.

If the ACCC intends not to place any benefits-related risk onto the TNSP, then there will be no requirement for optimisation and the initial value will simply be depreciated and adjusted for changes in replacement cost. Where there is a desire to allocate some or all the benefits risk to the TNSP, it is anticipated that this will be done through application of the Optimal Deprival Value (ODV) methodology[44]. This methodology is described in Section 5.3.1.

Our view is that, whilst revaluation based on ODV *can* be consistent with the principles set out above, and can be a mechanism to allocate a share of benefits risk to the TNSP, care must be taken to ensure that this is achieved: there must be both *consistency of measurement* in estimating the ODV and *consistency of application* in applying the ODV to the revenue setting process. These issues are discussed in sections 5.3.2 and 5.3.3, respectively.

[42] In other words, revenue is based on depreciated replacement cost with no optimisation

[43] It will be assumed that the asset "valuation" is a proxy for the NPV of the revenue that the TNSP is allowed to earn on that asset.

[44] Under the existing Code - and under the ACCC's issues paper on the SRI - it is anticipated that ODV will be used for revaluation. Many of the arguments put forward in this section would apply similarly to alternative valuation methodologies.

5.2. Initial Valuation

Since the Test is applied before any development commences, it will necessarily be on a budgeted cost. This budget will be based on estimated cost of the project together with contingency for cost increases or overruns: for example, those incurred as a result of additional environmental requirements applied during the planning approval process.

There is some incentive on the developer not to overbudget, since this could cause them to fail the Test[45]. However, this will be insufficient to prevent the developer deliberately inflating the budget if this were the value upon which the initial asset value were based.

For this reason, it is may be more appropriate to set the initial asset value at actual cost rather than budget cost. However, this has its own potential problems, specifically that the TNSP will "gold-plate" the project to inflate its asset base. There are a number of ways to mitigate this risk:

- disallow the actual from exceeding the budget except in exceptional and specified circumstances, and then at the discretion of the ACCC;
- do a technical audit of the budget prior to construction to check that it is prudent but not excessive;
- provide some form of sliding scale incentives to allow the TNSP to capture a proportion of any savings below budget, with the remainder passed through into the lower asset value.
- do an audit after construction is complete to check that declared costs were actually incurred.

The extent and complexity of these checks and balances would depend on the size of the project and also to what extent any subsequent revaluation is anticipated.

5.3. Subsequent Revaluation

If the ACCC wishes to allocate some benefits-related risk to the TNSP and, if this is to be done through revaluation based on ODV, what is needed to ensure that application of ODV allocates these risks properly? This section look at how to ensure a consistency between the Test process and the ODV re-valuation process. Section 5.4 looks at some possible approaches - to the Test and to ODV - which provide this level of consistency.

5.3.1. Summary of the ODV Methodology

Under the ODV methodology, the value of an asset (its ODV) is the smaller of its Depreciated Optimised Replacement Cost (abbreviated as DORC or sometimes ODRC) and its economic value (EV).

Calculating DORC

An asset's DORC is determined in the following steps:

[45] For example, due to a rival developer putting forward a similar augmentation scheme at a lower cost

1. Optimisation - Determine the modern equivalent asset, in an optimal network configuration, which provides the necessary level of service.

2. Optimised Replacement Cost - Determine its replacement cost using a standard or modular costing approach.

3. Depreciation - Determine the asset's depreciated value

The second and third of the DORC calculation steps are relatively deterministic, and not of direct relevance to the issue under discussion in this section. However, the EV assessment and the optimisation step are.

The optimisation step attempts to answer the question:

> Given the required level of service (determined by prescribed reliability standards and the pattern of supply and demand), what is the most cost-effective set of network assets to achieve that service?

Optimisation not only identifies cheaper (modern) network technologies, but also addresses the optimal asset size. In other words, the cheapest substitute may provide a lower service level (such as a smaller MVA rating) than the existing asset, if the existing asset were deemed to provide a level of service not warranted by reliability standards or supply and demand patterns (ie to be over-sized).

Calculating Economic Value

An asset's EV is the greater of the cost of the best substitute (at least cost) and its net realisable value. Net realisable value applies where the cost of substitutes is less than the asset's value if scrapped or otherwise disposed of.

The economic value assessment is similar in some respects to the optimisation process, in the sense that both processes involve identification and evaluation of substitutes. However, whilst the optimisation process is confined to identifying network asset (or technology) substitutes, the EV is concerned with identifying all other possible substitutes including demand options (including non-supply), non-electricity-related supply options and generation technology alternatives. In that sense, the process called "optimisation" is essentially a subset of the economic value assessment.

The reason these are identified as two distinct steps derives from the practical observation that in most applications of the methodology, network substitutes have significantly lower cost than other substitutes. Consequently, full economic value assessments do not need to be conducted except in relatively rare "borderline" cases.

Both the network optimisation and EV assessments involve a cost benefit analysis, in which credible substitutes can be compared. In both cases, different potential substitutes may have different incidence of cost over time (for example operating and maintenance), and so a net present value must be calculated.

5.3.2. Consistency of Measurement

Calculation of the ODV should be the exact reverse of calculating the augmentation benefit: if the augmentation is notionally dismantled, the Economic Value will be the net cost increase as a result, ie the difference in costs between a least-cost plan without the augmentation and a least-cost plan with the augmentation. The augmentation Test is basically equivalent to saying that the Economic Value should exceed the augmentation cost.[46]

However, this assumes that the same modelling and assumptions are used and that costs and benefits are measured on the same basis: ie direct costs and benefits to generators and Customers. Any differences between the two approaches may lead to inconsistent outcomes. Therefore, we propose that any Economic Value calculations should use the same models and analysis as have been proposed for the augmentation Test.

5.3.3. Consistency of Application

The conventional approach to applying ODV is to apply it to a depreciated replacement cost based on a straight-line depreciation of the asset across its economic life (eg 20 years). Where this leads to a devaluation of the asset, the TNSP loses revenue based on the amount of devaluation, and so fails to recover in full (on an NPV basis) the original capex[47]. This conventional approach may not deliver the risk allocation principles set out above. This is because the impact of ODV on revenue depends on the interaction between the timing of the anticipated benefits and the depreciation schedule. This can be illustrated by the following hypothetical example.

Suppose that a proposed augmentation successfully passes the test and, furthermore, that all augmentation benefits occur in the first five years of the augmentation. Suppose also that the TNSP is to recover revenue on this augmentation based on straight line depreciation over twenty years. Suppose that over the first 5 years the benefits accrue as expected and that when an ODV is calculated after 5 years the residual value is calculated as zero: ie the benefits for years 6 to 20 are zero, just as anticipated in the augmentation test. Therefore, the TNSP only recovers 25% of their capital, in spite of the fact that benefits have accrued to the market exactly as anticipated.

There are various possible approaches to ensuring consistency of application of ODV with the augmentation Test. Some suggestions are provided below.

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[46] This latter formulation appears to suggest we are moving from a "maximise net benefit" test to a "show positive net benefit" test. However, because the economic value is calculated by reference to the best option available if the augmentation did not go ahead, ODV exceeding cost implies that the best option without augmentation delivers lower net benefit than the augmentation: ie the augmentation does indeed maximise net benefit

[47] The devaluation can be treated as accelerated depreciation, in which case revenue is not lost but simply re-timed. This approach would be taken where there is no objective of allocating benefits-related risk to the TNSP, but there is still some need for optimisation to achieve other objectives.

5.4. Consistent Application of ODV to Revenue Setting

5.4.1. No Optimisation

The simplest approach is not to re-optimise at all. This places all the risk of benefits not eventuating onto market participants. However, it could be argued that these risks have been anticipated and measured as part of the augmentation Testing process (for example, through the analysis of a variety of scenarios and through the application of a high discount rate on the NPV calculation). In this view, passing the Test is equivalent to market participants saying: "yes, we have assessed the benefits, we have assessed the risks and, on balance, the augmentation should go ahead and we will take the good with the bad".

This is one view of the Test, but not the only view. So long as *any* benefits-related risk falls on market participants, an augmentation Test is necessary to protect these participants. The Test is only unnecessary where no risk is imposed on market participants, and this is effectively the non-regulated approach.

Some have suggested to us that the "no-optimisation" approach is particularly suitable for interconnectors, because many of the benefits of the interconnector are hidden or not immediately amenable to analysis: for example benefits of reduction in market power or reduction in ancillary service costs. This would certainly be the case if the ODV analysis was not sufficiently sophisticated to identify such benefits. However, we believe that an ODV employing similar analysis to that proposed for the augmentation Test should be able to measure such benefits.

5.4.2. Optimisation Honeymoon

A variation of the "no optimisation" approach is to have an "optimisation honeymoon" which means that there will be no optimisation for a significant period: eg 10 years. This will guarantee that the TNSP recovers at least a proportion of the capital invested - the exact proportion depending on the depreciation. This is a simple and therefore practical approach; a weakness is that it is difficult to achieve any particular risk allocation outcome through this method.

5.4.3. Revenue Sculpting based on Benefit Timing

Another way to ensure consistency of application of ODV is to sculpt the allowable revenue to match timing of benefits anticipated by the augmentation Test. This can be done through adjusting the depreciation schedule or by introducing alternative approaches to revenue setting. For example, if 75% of the benefits are anticipated in the first 5 years, then the revenue for the first 5 years should be such that 75% of the capital is recovered in this period (on an NPV basis). If an ODV is then applied at the end of this 5 year period, only 25% of the capital is at risk, and this reflects the risk to participants that the 25% of benefits that were expected to accrue after the first 5 year period may not eventuate.

5.4.4. Shortening the Test Period

Another approach is to change the test period to match the optimisation honeymoon. For example, a proponent may ask for the Test to be undertaken on the basis of recovering half their capital over the first ten years. The cost-benefit analysis would therefore compare 50% of the project cost with anticipated benefits over a ten year study (on an NPV basis as before). The initial asset value would be set at 50% of the capex and there would be no optimisation of this for the first ten years. The proponent could then retake the test in 10 years' time (or, equivalently, submit to an ODV against the 50% depreciated asset), or could alternatively operate the asset as an unregulated interconnector after the first 10 year period.

This approach is somewhat analogous to an unregulated interconnector owner auctioning 10 year access rights to the interconnector to fund a proportion of the development cost and then holding subsequent auctions once these rights have expired[48].

5.4.5. Correcting Information Asymmetry

One potential concern about the Test process is that an information asymmetry between the proponent and those stakeholders favouring alternatives could bias outcomes in favour of transmission. This might be a particular concern for intra-regional augmentations, where the test analysis is undertaken by the local TNSP, who will usually also be the proponent.

To a large extent this will be addressed through an appropriate consultation process at the time of the test analysis. However, to some extent, information asymmetry could be corrected ex-post, through re-valuation. For example, if the Test was passed through reliance on a demand forecast provided by the TNSP, it may be appropriate to re-value the asset at a later date if this demand forecast did not eventuate. On the other hand, if the Test relied on an independent demand forecast, such a revaluation may not be appropriate.

Where Test benefits are dependent on certain promised service standards being achieved (eg service availability) it may be appropriate for these benefits to be re-assessed if these standards are not achieved, and the asset revalued accordingly.

5.5. Conclusions

The Test establishes the augmentation as a regulated asset, but how it is regulated is a matter for the ACCC and, in particular, should be based on how the ACCC considers that the risk of the anticipated benefits not eventuating should be appropriately allocated between the TNSP and the market participants. Passing the Test should not necessarily mean that no further risk should be placed on the TNSP, although this is certainly an option.

However, whatever the preferred allocation, we believe that there should be a fundamental principle that, if the benefits eventuate as anticipated by the augmentation Test, the TNSP should be able to recover in full the capital expenditure associated with the augmentation - assuming there are mechanisms in place to ensure that the actual construction cost is at a prudent level consistent with the capex value that was used in the

[48] The difference, of course, is that the unregulated interconnector may be able to capture revenue in excess of their investment cost, whereas the regulated interconnector will be capped at this level, even where the identified benefits are much higher.

Test (and leaving aside the possibility of changes to replacement cost which may impact on revenue).

We believe that there are three fundamental requirements to achieving this principle:

- the initial value should be equal to the actual capital cost, so long as there are appropriate protections in place to prevent gold-plating;
- any ODV calculations should be consistent with the calculations undertaken in the augmentation test: the same categories of benefit should be captured for the purposes of calculating Economic Value and the same type of modelling should be used;
- any application of the ODV result to revenue setting must take into account the timing of benefits anticipated by the Test to ensure that revenue is only impacted if there is a decline in future anticipated benefits (as measured by the ODV) compared to those benefits anticipated by the Test for the same time period.

Furthermore, the basis for any future re-valuations should be known and clear to the TNSP at the time of the augmentation: this may be through the SRI, or agreed bilaterally on a case-specific basis.

6. Implementation Issues

6.1. Consistency between the Augmentation Test and Asset Valuation

We noted in Section 5 two areas where there should be consistency between the augmentation Test and valuation of regulated assets:

1. where the Test is passed, the initial value of the augmentation-related assets should be based on the capex figure that was used in the Test;

2. the Economic Value calculation in the ODV methodology should capture the same costs and benefits as those analysed in the Test, and model them in a consistent way

Since the Test is undertaken pursuant to the Code, and valuation is undertaken pursuant to the SRI it seems appropriate that either the Code should cross-refer to the SRI or the SRI should cross-refer to the Code. NEMMCO has put forward Code changes that take the former route: ie the Chapter 5 augmentation processes refer to a "regulatory test" which will be specified by the ACCC as part of its SRI. We believe this approach is appropriate. It raises two other questions, however. How should the regulatory test be specified in the SRI? And is it appropriate that non-regulators (eg NEMMCO, the IRPC or the TNSP) should apply a regulatory test. These issues are considered below.

6.2. How should the Regulatory Test be specified

The main consideration here is the consistency between the Code application of the Test and the ACCC's application of Economic Value. The greater the detail, the less scope there is for interpretation and the more likelihood there is of consistency. Therefore the regulatory test should at least provide guidance on:

- whose costs and benefits to consider
- which costs and benefits to consider
- how to identify and measure those costs and benefits (including what range of discount rates to employ)

During discussions we received a suggestion that the decision criterion should not be tightly specified at first, but should be allowed to develop over time (in much the same way that the application of law evolves) through decision precedence and review based on real world tests. We believe that some details of the methodology should be allowed to evolve over time, but that the principles should be as clear as possible at the start of the national market.

6.3. Roles and Responsibilities

Although questions of who should write the decision criterion and who should apply it are not specifically within the scope of this review, we believe they are relevant

questions. This section contains a brief discussion of the issues we have identified in this regard.
To the extent that discretion and judgement are provided for, it would be preferable to have only one decision-maker, to avoid potential inconsistency. In other words, it may be preferable for the ACCC to be the decision-maker under chapter 5 as well as under chapter 6. On the other hand, if the Test is described in a reasonable level of detail, the risks of inconsistency will be reduced. Therefore, the decisions on how much detail should be provided and who should make the decision are closely related.

In our discussions to date we received several comments on the roles of the IRPC and NEMMCO in this matter. In particular, some expressed the following opinions:

- The constitution of the IRPC, being representative largely of TNSP and NEMMCO interests (rather than network users), could lead to perceptions of bias in its application of a public benefits test and in its recommendations.

- NEMMCO has a predominantly short term operational focus which might cause perceptions of bias in its determinations on transmission augmentation.

- The ACCC is better placed to determine whether a transmission augmentation should be regulated or not, given that it determines network owners' regulated revenue in any case. Furthermore, the valuation methodology it employs will be transparent (in its SRI) and its approach to valuation is already well guided and appropriately bounded in chapter 6 of the Code.

7. Related Reviews

A fairly common concern that has been expressed to us is the difficulty of arriving at appropriate transmission augmentation and valuation processes when a number of aspects of the market which are closely related to these processes are currently being reviewed in separate forums. We are sympathetic to these concerns and, as far as possible, have recommended approaches to the augmentation issues which are reasonably robust to different possible outcomes from these reviews.

This section sets out where we believe our conclusions may need to change, and where they won't need to change, in the light of different review outcomes. There is not intended to be any suggestion from this that certain outcomes of these other reviews are preferred by us and we believe the expression of such preferences is beyond the scope of our engagement and this report.

7.1. TUoS Review

NECA is currently undertaking a comprehensive review of TUoS, covering such issues as who should pay TUoS and what locational signals should be applied through TUoS. We recommended (in Section 4.1) that who pays TUoS should have no bearing on how the benefits test is applied: specifically, just because a certain sector of the market does not pay TUoS, it does not mean that this sector's benefits should be excluded from the benefits analysis. Efficient augmentation requires that the analysis covers a wide range of market benefits across all sectors of the market.

Some have raised concerns that applying this wide benefits test, coupled with particular TUoS charging outcomes, may lead to inefficient investment decisions. However, as noted previously, we believe that it is inappropriate for the Test to attempt to overcome these possible concerns by narrowing the benefits test, since this will simply introduce more potential inefficiency.

Another linkage that has been raised is that the necessity for a regulated solution to augmentation arises from the fact that TUoS is charged to Customers rather than generators. The suggestion is that, if augmentation costs were charged to generators, the individual generator (or coalition of generators) could make its own decision as to whether it was prepared to pay for the investment or suffer the consequences of not investing. If a regulated solution is imposed - through the Chapter 5 process - a generator could be forced to pay TUoS in relation to an augmentation (assuming it passed the Test).

We believe there would be no need to alter the Test in this circumstance. If the generator disagreed with the estimated benefits proposed by the TNSP, it could make submissions to this effect in the consultation process. If (to take an extreme example) all the benefits were estimated to accrue to that generator (or coalition) and the generator disagreed with this estimation, it would seem likely and appropriate that the augmentation would fail the Test.

On the other hand, if the generator considered that its *share* of the benefits did not cover its *share* of TUoS, that is unfortunate and may be rectifiable through TUoS, but should not be grounds for the augmentation failing the Test.

7.2. Unregulated Interconnectors

Another part of the NECA review is to develop a framework for non-regulated interconnectors to enter the market. At present, the Code does not describe in detail how a non-regulated interconnector should operate within the market and what revenue it should receive. Various arguments have been put to us in relation to unregulated interconnectors:

- that regulated interconnectors are unnecessary since any market need will be met through unregulated interconnectors
- that it is hard to design a Test which allows unregulated interconnectors to compete fairly with regulated interconnectors, until the former are better defined and understood
- that no regulated interconnectors should be approved until the unregulated interconnector framework is defined and approved and proponents have had an opportunity to develop unregulated options.

Some submissions [TransEnergie] suggest that the net benefit test should be preceded by a "market failure" test. That is, a proposal for regulated augmentation should first demonstrate that some market failure will prevent a non-regulated option being built. In principle we accept this view, and we believe this issue is covered by the market-driven expansion modelling discussed in section 4.3.

We have not explicitly attempted to achieve "competitive neutrality" between regulated and non-regulated interconnectors, preferring to focus on ensuring fair and efficient competition between local and remote generation. However, in confining allowable benefits to market-type benefits, in proposing to apply a commercial discount rate to the cost-benefit analysis, and in requiring a burden of proof on regulated interconnectors, we believe that we have addressed many of the concerns of those who fear that the augmentation Test could discriminate against non-regulated interconnectors.

Some have raised the possibility of "hybrid" options: part-regulated and part-unregulated, although such entities are not currently recognised or anticipated in the Code. The NECA working group considering unregulated interconnectors define "hybrids" as entrepreneurial interconnectors which can derive some income from regulated network service charges, and can also derive some income through participation in the market.

It is clear that, if hybrid interconnectors were established under the Code, an augmentation test would still be required but this test may need to look quite different from the Test described here for regulated interconnectors. It does not seem to be useful to consider, at this time, what that test may look like.

7.3. Capacity Review

NECA is also carrying out a review on the “Review of Capacity Mechanisms”. This stems from the concern - described in Section 4.2.6 above - that current signals and incentives provided by the market may be insufficient to maintain reliability standards at the levels established by the Reliability Panel.

The outcome of this review may have a significant impact on the Test, although more at the detailed modelling level than in relation to the fundamental principles. Indeed - as noted above - it is hard to know how reliability should be treated (and specifically what level of VoLL should be used for USE) until this issue is resolved.

Two possible outcomes of the review would be to raise VoLL to a level compatible with the reliability standard, or to lower the reliability standard to a level compatible with existing VoLL. Either would resolve the issue of what VoLL to use in benefit analysis.

A third possible outcome would be to introduce new instruments or price signals which rewarded those parties providing system reliability benefits to the market. In this case, this potential revenue should be modelled in the analysis, for both transmission and generation options.

A fourth possible outcome is that a “central planner” (eg NEMMCO or jurisdictions) has responsibility for procuring “reliability support” outside the market. This “reliability support revenue” could be treated in the same way as other external revenue (eg Telecoms) under the test.

There may be other possible outcomes. However, it appears that, although the Test will need to be adjusted to accommodate the outcome of this review, the correct adjustment will be readily apparent from the principles and approaches already described.

8. Recommendations

8.1. Augmentation Test

We recommend the following.

- The chapter 5 transmission augmentation criterion should be based on net benefits accruing to generators and customers (both wholesale and retail).

- The relevant benefits to measure are those that can also be captured by non-regulated alternatives: for example, savings in costs associated with energy and ancillary services, and improvements in reliability, priced at a level consistent with spot market mechanisms. External benefits not able to be captured through the market - such as environmental benefits - should not be included within the analysis.

- The test should require an augmentation to maximise benefits. This should mean that the proposed augmentation delivers more anticipated benefits than any identifiable alternative across a range of (although not necessarily all) forecast scenarios.

8.2. Asset Valuation

We recommend the following.

- For the purposes of this report, asset valuation and re-valuation (ie optimisation) by the ACCC should be seen as a mechanism for sharing, between the TNSP and market participants, the risk that the market benefits identified by the augmentation test do not eventuate.

- The fact that the test has been passed does not necessarily mean that the TNSP should be insulated from any further benefits-related risk, although this is one possible outcome. The appropriate allocation of risk is a matter for the ACCC. However, it is important that basis for any future re-valuations should be known and clear to the TNSP at the time of the augmentation: this may be through the ACCC's SRI, or agreed bilaterally on a case-specific basis.

- If the ACCC were to adopt the ODV (or another valuation) methodology, its calculations should be consistent with the calculations undertaken in the augmentation test: for example, the same categories of benefit should be captured for the purposes of calculating Economic Value and the same type of modelling should be used.

- Care should be taken in applying ODV to ensure that the TNSP is not impacted simply due to a mismatch between the timing of benefits and the depreciation scheduled adopted to determine allowable revenue. We have suggested a number of approaches to ensure consistency between the augmentation test, ODV and revenue setting.

Appendix 1: Glossary of Abbreviations and Relevant Terms

ACCC	Australian Competition and Consumer Commission
augmentation	Any addition to a network which increases its service potential
Customer	A defined term in the Code which means a wholesale purchaser - ie a Code Participant who purchases energy at spot prices
Customer	In this report, we mean a person who purchases electricity at either wholesale or retail prices: ie both retailers and consumers.
DORC, ODRC	Depreciated Optimised Replacement Cost - a notional cost which provides an upper bound to an asset's value under the ODV methodology.
EV	Economic Value - another upper bound to an asset's value, based on the cost of the cheapest substitute
interconnector	A transmission line connecting transmission networks in adjacent regions
IRPC	Inter-Regional Planning Committee
NECA	National Electricity Code Administrator
NEMMCO	National Electricity Market Management Company
ODV	Optimised Deprival Value
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System
USE	Unserved Energy - the amount of load disconnected by the market operator to preserve system security
VoLL	Value of Lost Load - the estimated cost to consumers (in \$/MWh) of disconnected load

Appendix 2: Regulated vs Unregulated Transmission

This sub-section contains a brief discussion on the reasons for regulation of network services in the NEM, and develops the view that although regulation may be warranted most of the time, it is inappropriate to assume that all network assets should be regulated exclusively.

Transmission and distribution networks are commonly considered to be natural monopolies, and owners of such infrastructure have the opportunity to engage in a number of practices that could prevent competitive outcomes. It is for this reason, at least in part, that decisions to augment transmission networks (thereby extending potential monopolies) must satisfy a public benefits test.

More generally, we take the view that transmission networks (and even individual components of networks) may have monopoly characteristics, or other characteristics, which mean that regulation may be appropriate, to prevent monopoly pricing and to ensure efficient investment. For example, in the context of inter-connector augmentation, a service providing significant public benefits might not proceed as an unregulated investment because the investor cannot effectively capture a sufficient portion of those benefits by contracting in the market. Such a situation could be regarded as market failure (due to “public good” externalities), and intervention (in the form of a regulated augmentation) in this case could be justified.

It is important to recognise that although the code provides for regulated networks, it does not preclude the development of unregulated (or entrepreneurial) transmission assets (at least inter-connector services). Furthermore, the ACCC in its 1997 authorisation determination refers to the desirability of pricing signals which can influence both the pattern of demand for network services, <u>and investment in network services</u>.

> Ideally the pricing structure should provide price signals which reflect the extent of congestion or spare capacity at different points of the network and so influence the pattern of demand for network services. It should also provide efficient signals for investment in augmentation of congested parts of the network.

The important element of this opinion in the context of this review is that the transmission augmentation decision criterion must not start with the presumption that all transmission must be regulated. Rather, it should presume that both energy and network price signals will efficiently influence behaviour, including investment in unregulated transmission assets, unless there is sufficient evidence to the contrary.

Where there is evidence or threat of a specific market failure (whether due to transmission market dominance, or to the “public goods” characteristics of some assets, high transaction costs, poorly defined property rights, or other reasons) regulated transmission investment (or other intervention) will probably be justified. But such evidence must be established on a case by case basis. This is also alluded to by the ACCC in its 1997 determination:

Market definition in the energy sector requires a case by case approach. The factors which impact on competition differ substantially in individual cases. Circumstances vary with geographic regions, the functional level of the market and energy applications. The impact of regulatory changes affecting energy markets will not be uniform. How and where market power may arise will depend on a range of factors, few of which will be consistent throughout the economy.

We take the view that regulated transmission augmentation (especially inter-regional inter-connection) may be but one way to address some market failures. For example, presence of generator market dominance in a region may be addressed by the ACCC via remedies available under the Trade Practices Act. Building a regulated inter-connector may also reduce market power, but is not necessarily the most cost-effective way to facilitate competition.