MURRAYLINK Transmission Company

GPO Box 7077
Riverside Centre, Brisbane, 4001
Level 11, 77 Eagle Street, Brisbane, 4000
Phone: 61-7-3211 8617
Facsimile: 61-7-3211 8619

on behalf of **MURRAYLINK Transmission Partnership**

8 April 2003

Sebastian Roberts
Acting General Manager, Regulatory Affairs – Electricity
Australian Competition & Consumer Commission
GPO Box 520J
Melbourne VIC 3001

Dear Mr Roberts

Application for Conversion to a Prescribed Service and Maximum Allowable Revenue

On behalf of Murraylink Transmission Partnership ("**MTP**"), Murraylink Transmission Company ("**MTC**") appreciates the opportunity to provide additional information to address issues that have arisen during the Commission's consideration of MTC's Application of 18 October 2002.

This response is supplementary to, and should be read in conjunction with, MTC's Application. MTC may also provide additional responses to the Commission's draft decision and Commission staff have confirmed that the Commission will accept any such additional response from MTC.

1. Rationale for Conversion

Several stakeholders have suggested that the Commission consider MTC's reasons for conversion and have referred to the source of the National Electricity Code ("**Code**") provisions and other matters that they believe are relevant. In light of the recent submissions made by stakeholders, we state the context in which MTC's Application is made and, in so doing, have restated some matters that have previously been addressed in MTC's Application of 18 October 2002 and its submissions of 28 February 2003 and 17 March 2003.

Safe Harbour Provisions

The rationale for having within the Code a process of conversion from a market network service to a prescribed service can be identified in the report *Entrepreneurial Interconnectors: Safe Harbour Provisions* ("**Safe Harbour Provisions**"). This report of the National Electricity Code Administrator ("**NECA**") Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors made recommendations on the manner in which market network services would be introduced into the National Electricity Market ("**NEM**").

The NECA Working Group acknowledged that, although the impetus to establish the NEM arose from an expectation that competitive market based arrangements would be likely to yield more efficient outcomes and ultimately greater benefits to consumers, serious technical impedients existed to moving to a competitive market in network services. The NECA Working Group identified non-regulated interconnectors as one exception in which it might be feasible, in certain circumstances, to adopt a competitive approach to inter-regional transmission.

In the NECA Working Group's view, the Safe Harbour Provisions represented a logical progression towards market-based provision of transmission services. It nevertheless acknowledged that the concept of non-regulated interconnectors was "somewhat experimental" and therefore recommended that an entrepreneurial interconnector be given the right to apply to convert to regulated status *at any time*. In the NECA Working Group's view, the option to convert would help ensure that investment was not inefficiently inhibited by non-commercial market design risks that only become apparent once the first interconnectors are operational.

The NECA Working Group made the following recommendation:

> *Option to convert to regulated status.* The interconnector owner can apply to convert to regulated status at any time. The revenue entitlement will be assessed at that time.

NECA subsequently made application to the Commission for authorisation under the *Trade Practices Act 1974* of a number of amendments to the Code, including those recommended in the Safe Harbour Provisions and, in particular, clause 2.5.2(c):

> 2.5.2(c) If an existing *network service* ceases to be classified as a *market network service* it may at the discretion of the *Regulator* or *Jurisdictional Regulator* (whichever is relevant) be determined to be a *prescribed service* or *prescribed distribution service* in which case the *revenue cap* or *price cap* of the relevant *Network Service Provider* may be adjusted in accordance with chapter 6 to include to an appropriate extent the relevant *network elements* which provided those *network services*."

In its final determination of NECA's authorisation application, the Commission granted authorisation for NECA's proposed amendments to the Code and also noted that[1]:

> …as the clause [2.5.2(c)] is currently drafted no justification is required prior to reclassifying a market network service as a prescribed network service, although the regulator has the discretion to determine whether or not a network service may be classified as a prescribed network service.

In keeping with this rationale for the process of converting status from a market network service to a prescribed service, MTC considers that it may apply for conversion at any time and that no separate justification is required. Nevertheless, in order to assist the Commission on matters raised by stakeholders, MTC submits the following.

Responses to Specific Stakeholder Issues

(i) Uncertainties associated with the development and administration of the NEM

According to the Safe Harbour Provisions, one purpose of the conversion process is to assist non-regulated interconnectors to avoid "non-commercial market design risks". The Allen Consulting Group concludes that the opportunity to convert is

[1] Australian Competition and Consumer Commission, 21 September 2001, *Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers*, p. 137.

appropriate given that, without some form of protection against unfavourable regulatory developments that affect the ability of investors to capture the benefits created, it may well be that investment in unregulated interconnectors would be seldom financially viable.

In fact, the Murraylink Transmission Partners would not have decided to invest in Murraylink had it not been for the explicit opportunity stated in the Code for Murraylink to be converted to a prescribed service.

In its Application, MTC stated that, over the past three years during Murraylink's development, the NEM has experienced a high level of uncertainty particularly in relation to the interaction between the competitive and the regulated segments. As a consequence of that uncertainty, MTC now believes that Murraylink is more appropriately operated to provide a prescribed service in the same manner as most other transmission assets in Australia.

Specific uncertainties associated with the interaction between the competitive and the regulated segments of the NEM experienced by MTC include the following.

- There has been controversy surrounding whether the South Australia to New South Wales Interconnector ("**SNI**") project is justified; and
- The South Australian Electricity Supply Industry Planning Council concluded that a suitable network support agreement is required in conjunction with Murraylink to fully provide adequate network performance in the Riverland[2], and while MTC has been willing to offer such network support, no suitable network support agreement has been negotiated.

More generally, MTC is concerned about serious deficiencies that remain in the NEM and the impact these deficiencies could have upon its business as a market network service provider. Since MTC lodged its Application with the Commission, the report of the Council of Australian Government's Independent Review of Energy Market Directions ("**Parer Report**") confirmed several serious deficiencies[3]. MTC concurs with many of the findings of the Parer Report and, in particular nominates the following deficiencies as ones that affect MTC:

- the energy sector governance arrangements are confused;
- there are perceptions of conflict of interest;
- electricity transmission investment and operation is flawed; and
- the financial contracts market is illiquid, in part reflecting regulatory uncertainty.

The Parer Report recommendations have not received unified support from State and Commonwealth Governments or from the electricity industry. Consequently, a clear program of reforms to the NEM institutions, governance and national transmission planning has yet to be devised.

[2] Electricity Supply Industry Planning Council, December 2001, *Riverland Augmentation Report*, p. 19.
[3] Council of Australian Government Independent Review of Energy Market Directions, 20 December 2002, *Towards a Truly National and Efficient Energy Market: Final Report*, p. 9.

(ii) Bypassing the Regulatory Test

Some stakeholders have expressed concern that MTC may gain a commercial advantage from the Commission granting conversion of Murraylink rather than requiring MTC to conduct the process set down in the Code for the establishment of proposed new large network assets involving assessment under the Commission's *Regulatory Test for New Interconnectors and Network Augmentations* ("**Regulatory Test**").

The NECA Working Group also stated that it was:

> …important that the conversion option should not shield the proponent from normal commercial risks, e.g. the risk of having over-judged the future demand for the interconnection service.

We note that the NECA Working Group stated that the way to address this issue was to ensure that the regulated revenue entitlement is based on the assessed need for the facility at the time of the conversion application, rather than guaranteeing a return on the original capital cost.

The Commission has acknowledged this point in its final determination of NECA's authorisation application when it said that[4]:

> The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions. As such the investor would bear the risk of the Commission optimising down the value of the assets – with the consequence of reduced revenue streams, at the time it converted to regulated status and at each regulatory review into the future.

In consultation with the Commission, MTC has, in its Application, developed and applied a regulatory asset valuation methodology for Murraylink that is consistent with the requirements of the Commission's *Draft Statement of Principles for the Regulation of Transmission Revenues* ("**Draft Regulatory Principles**") and the manner in which the Commission values other new and existing assets. In those circumstances, MTC, by utilising the conversion process, accrues no material advantage over proponents of new assets, even if, as some have argued, the conversion process is administratively simpler than conducting the Regulatory Test.

(iii) Applicability of the Regulatory Test to asset valuation

Some stakeholders have suggested that the Commission's Regulatory Test itself should be used to determine Murraylink's regulatory asset value.

The Regulatory Test provides a complementary but distinctly different purpose to that of the asset valuation methodology set down in the Commission's Draft Regulatory Principles. The Regulatory Test is designed to assess the costs and benefits of a range of possible network developments during the early stages of project planning

[4] Australian Competition and Consumer Commission, 21 September 2001, *Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers*, p.137.

before an asset has been constructed, rather than valuing an existing asset. It can, however, provide guidance for the manner in which an existing asset's economic value can be calculated.

For the reasons stated in (ii) above, MTC has proposed a regulatory asset value for Murraylink that is consistent with the valuation methodology set down in the Draft Regulatory Principles, and which has been determined in a manner consistent with the intent of the Regulatory Test.

(iv) Existing Code provision

Stakeholders have suggested that the Commission's determination that Murraylink may convert to regulated status will promote a covert method for establishing a regulated asset and involves a misapplication of the Commission's discretion. Some have even suggested that the Commission should deny MTC's Application because the option to convert should not exist.

MTC's Application is made under an existing Code provision that has been duly authorised by the Commission. The Commission should assess each application made pursuant to clause 2.5.2(c) of the Code on a case by case basis. To the extent there are any deficiencies in that provision, these deficiencies should be addressed through appropriate future Code changes.

(v) Improvements to the operation of the NEM

Some stakeholders have suggested that conversion of Murraylink would provide no overall benefit to the NEM. The Allen Consulting Group[5] concludes that Murraylink's conversion to a prescribed service may provide substantial efficiency improvements to the operation of the NEM by removing any incentive that MTC may have to withhold Murraylink's capacity and by providing a more certain environment for the planning and operation of the NEM.

(vi) Investor confidence

Some stakeholders have suggested that Murraylink should not be converted simply because it was built to provide a market network service. Stakeholders have also suggested that Murraylink's asset value should be determined in a manner that sets MTC's revenue at a potentially unsustainable level.

MTC submits that the Commission's determination of its Application will influence future investment. Future investors will look to the Commission's decision of the MTC Application as an indication of the extent to which they may rely upon the Commission to exercise its discretion in a reasonable manner that ensures the substantial value that an asset provides is fairly recognised.

[5] The Allen Consulting Group, April 2003, *Commentary on Economic Issues* (Attachment 1), pp. 4-5.

2. Murraylink Ceasing to Provide a Market Network Service

Clause 2.5.2(c) of the Code provides as follows:

> 2.5.2(c) If an existing *network service* ceases to be classified as a *market network service* it may at the discretion of the *Regulator* or *Jurisdictional Regulator* (whichever is relevant) be determined to be a *prescribed service* or *prescribed distribution service* in which case the *revenue cap* or *price cap* of the relevant *Network Service Provider* may be adjusted in accordance with chapter 6 to include to an appropriate extent the relevant *network elements* which provided those *network services*.

Several stakeholders have commented that once Murraylink's network service has ceased to be classified as a market network service and is converted to a prescribed service, it should not have the opportunity to be converted back to a market network service. MTC accepts that once Murraylink's network service has been a prescribed service, clause 2.5.2(a)(3) of the Code will operate so as to preclude it from being reclassified as a market network service.

Some stakeholders also suggest the wording of clause 2.5.2(c) implies that MTC should not be entitled to apply to the Commission for conversion of its market network service to a prescribed service without also committing to proceed with the conversion once the Commission makes its determination of the application. Such a commitment is not required under the Code nor would it be reasonable for the Commission to expect MTC to make it.

MTC and MTP are committed to achieving regulated status for Murraylink, and they have confidence that the Commission will make a sound determination generally in accordance with the proposals put forward in the MTC Application.

MTC supports the process set by the Commission for making its determination in respect of this application, given its consistency with the revenue cap and authorisation processes previously undertaken by the Commission. In particular, the public consultation included in the Commission's process provides ample opportunity for all stakeholders to put forward their views on all the technical, economic and regulatory issues surrounding MTC's Application.

MTC submits that it is most appropriate and open for the Commission to make a determination of the MTC Application that is conditional upon Murraylink's network service ceasing to be classified as a market network service. MTC is making arrangements to ensure that Murraylink's network service will be able to cease to be classified as a market network service after the Commission hands down its determination.

3. Economic and Regulatory Policy Issues

Given that MTC's Application is the first of its kind, and that clause 2.5.2(c) of the National Electricity Code ("Code") is silent as to the manner in which the Commission is required to assess the Application, it is understandable that stakeholders would raise a range of economic and regulatory policy issues. The issues raised by stakeholders relate to both whether Murraylink's network service should be converted to a prescribed service and, if so, the manner in which Murraylink's regulatory asset value should be determined.

MTC has commissioned The Allen Consulting Group to analyse the issues raised by stakeholders in terms of the need for the Commission to adopt sound regulatory and economic practice (**Attachment 1**). The Allen Consulting Group concludes that:

- the ability to convert market network services to prescribed services provides a reasonable foundation for new commercial investment given the uncertainties associated with the development and administration of the NEM;
- there are substantial shortcomings associated with an "incremental benefits" asset valuation approach as proposed by National Economic Research Associates and others;
- the asset valuation approach proposed by MTC in its application is consistent with the deprival value method described in the Commission's Draft Regulatory Principles, and is the most appropriate approach for the valuation of Murraylink for reasons of consistency, economic efficiency, predictability, and administrative efficiency; and
- if an asset such as Murraylink is converted to regulated status and a duplicate interconnector is built, customers would not pay for the same network service twice, even if the duplicate is deemed to pass the Commission's Regulatory Test.

The Allen Consulting Group also discusses other stakeholder comments: MTC's proposed commercial discount rate, weighted average cost of capital and regulatory control period.

MTC endorses The Allen Consulting Group commentary and commends it to the Commission.

4. Murraylink's Service Standard

Comments by stakeholders raise no new issues and provide no new information in relation to Murraylink's service standard. As stated in its letter of 28 February 2002, MTC's position remains that Murraylink's service standard should be its circuit availability with a target level of 97%. MTC accepts PB Associates' recommendation that there be individual performance targets and proposes target values of 0.96%, 0.91%, and 1.13% for planned, forced peak and forced off-peak respectively. These targets are more realistic for Murraylink, given its location and the nature of Australian high voltage switching and isolation requirements. MTC still anticipates agreeing with the Commission an appropriate list of *force majeure* events, as stated in our letter of 28 February 2003.

5. Murraylink's Power Transfer Capability

MTC notes that several stakeholders highlighted the findings of PB Associates in its *Transfer Capability Review of Murraylink Application to ACCC*. PB Associates endorsed TransÉnergie Australia's ("**TEA's**") assessment of the power transfer capability of Murraylink except for the case in which incremental generation is available in the Victorian region during peak load periods. In that case, PB Associates indicated that additional dynamic studies were required to confirm the 220 MW transfer level TEA suggested. As foreshadowed in our letter of 28 February 2003, MTC has commissioned dynamic studies and confirmed their results with the Victorian Energy Networks Corporation ("**VENCorp**").

Subsequently, on 14 March 2003, VENCorp wrote to the Commission to indicate that VENCorp has concluded that:

- VENCorp's calculation of Murraylink's power transfer capability is consistent with figures quoted by PB Associates when the necessary changes to the study case are taken into account; and
- additional augmentations required for up to 220 MW Murraylink transfer capability are feasible.

One stakeholder submission called into question the accuracy of the base case files used by TEA in making its assessment given that Power Technologies ("**PTI**") found that these files displayed overloads and voltage violations under normal operating conditions without Murraylink in place. The same submission suggested that PTI had incorrectly applied voltage limitation criteria. TEA advises MTC that its base case files are accurate and that PTI applied the correct voltage limitation criteria. VENCorp's concurrence with TEA's conclusions demonstrates this. However, should the Commission require any further information on this matter, MTC would be very pleased to provide it.

In its submission, ElectraNet SA puts forward a number of new constraint equations for Murraylink. Constraint equations vary from time to time with changes in system conditions such as line equipment re-ratings and outages. The constraint equations used by TEA to assess Murraylink's transfer capability and by TEUS to determine Murraylink's market benefits are derived from the work of the Inter-regional Planning Committee ("**IRPC**") and its Interconnection Options Working Group ("**IOWG**"). TEA advises MTC that the constraint equations TEA has used are reasonable representations of Murraylink's transfer capability for longer-term planning and regulatory purposes.

Some stakeholders suggested that MTC should involve the IRPC and the IOWG in a public process to assess the power transfer capability of Murraylink. The IRPC and the IOWG have already assessed Murraylink in accordance with the Code and there is no legal requirement or technical need to involve them at this point.

It has also been suggested that MTC should be responsible for any advancement costs associated with any network augmentations that are required due to the operation of Murraylink. MTC agrees with TransGrid that it is appropriate that MTC has assumed that the identified power transfer capability can be maintained for the life of the project through the progressive upgrading of the upstream systems by the relevant transmission network service providers.

MTC submits that the limits of Murraylink's power transfer capability that TEA assessed and that TransÉnergie US ("**TEUS**") used to calculate Murraylink's market benefits, are confirmed as valid.

6. Commercial Discount Rate

One submission raised a number of criticisms of the commercial discount rate used by TEUS and Burns and Roe Worley ("**BRW**") to calculate the present value of Murraylink's market benefits and the present value the costs of Murraylink's alternative projects, respectively.

MTC has sought further advice from Deloitte Touche Tohmatsu ("**DTT**") on the manner in which it derived the commercial discount rate TEUS and BRW used.

DTT's subsequent advice is contained in **Attachment 2** and it confirms the value of the base commercial discount rate put forward in DTT's original advice contained in Appendix C of the MTC Application. DTT also find that the low and high discount rates it suggested in its original advice should be reduced slightly.

7. Calculation of Murraylink's Market Benefits

Submissions raised a number of issues about the manner in which TEUS calculated Murraylink's market benefits.

A common issue with stakeholders was the number of market development scenarios and sensitivities TEUS examined. In its letter of 17 March 2003, MTC submitted a paper from TEUS in which TEUS described the results of its examination of a number of market development scenarios and sensitivities. The results of TEUS's market development and sensitivity calculations demonstrate again that TEUS's base case calculation of Murraylink's market benefits is sound, robust and conservative.

Some stakeholders have suggested that TEUS should derive Murraylink's market benefits from a probability weighted aggregation of the scenarios. MTC concurs with The Allen Consulting Group[6] that this approach would be inappropriate and would remove the objectivity with which Murraylink's market benefits are determined.

TEUS did not consider SNI in its calculation of Murraylink's market benefits as a regulated interconnector. Firstly, MTC believes that SNI does not satisfy any of the National Electricity Market Management Company ("**NEMMCO**") criteria for committed project status[7]. Secondly and more importantly, given that:

- the Commission has not determined SNI's regulatory asset value for the purpose of setting its proponent's revenue cap;
- Murraylink may become a regulatory interconnector; and
- the actual capital cost of SNI might be significantly greater than the market currently expects[8],

the commercial opportunity of proceeding with SNI as currently defined is likely to be reassessed by its proponent with the probable outcome being that the proponent would only proceed with a project similar to "unbundled SNI"[9].

TEUS has prepared further comments on its calculation of Murraylink's reliability benefits and other modelling issues and these comments are contained in **Attachment 3**. This paper

[6] The Allen Consulting Group, April 2003, *Commentary on Economic Issues* (Attachment 1), p. 16.
[7] NEMMCO 2002*, Statement of Opportunities for the National Electricity Market*, p. 2-5.
[8] Refer to section 8 and Attachment 6 of this letter.
[9] In this letter, "unbundled SNI" is defined as being the project assessed in NEMMCO's *Determination under Clause 5.6.6: SNI Option* of December 2001 without the Buronga to Robertstown transmission line or the new facilities at Robertstown.

confirms the appropriateness of TEUS's approach to the calculation of Murraylink's reliability benefits and deals with stakeholder issues associated with Riverland deferral benefits, Snowy dispatch, double counting generation deferral, Heywood lightning detection, thermal limits, intraregional constraints, and modelling Murraylink limits with Prosym software.

Given the relatively recent development and implementation of HVDC Light technology, some stakeholders are not well informed about the loss characteristics of Murraylink. TEUS has prepared a memorandum that described the nature of Murraylink's losses and their treatment in TEUS's calculation of Murraylink's market benefits. This memorandum is contained in **Attachment 4**.

MTC believes that the information put forward by TEUS confirms the integrity of its original calculations set down in Appendix D of the MTC Application.

8. Criteria for Selection and Costing of Alternative Projects

MTC affirms the criterion that BRW has applied to the selection of alternative projects for the purpose of determining Murraylink's regulatory asset valuation[10]. This criterion is that the alternative projects must provide the same level of service (and thus the same market benefits) as Murraylink. The Allen Consulting Group[11] explains the rationale for this approach. MTC agrees with the Commission's statement in its February 2003 Issues Paper that [BRW's] selection of alternative projects is consistent with an Optimised Depreciated Replacement Cost[12] valuation process.

MTC believes that many stakeholders confused the criteria for the selection of alternative projects for the purpose of determining an existing asset's regulatory asset valuation with the criteria that would be used for the purpose of conducting the Regulatory Test as a planning exercise.

Stakeholders have made a range of other comments on BRW's selection and assessment of alternative projects, in particular: the nature of alternative projects; the inclusion of some technical features, the particular component costings and the inclusion of profit and overhead in the costing estimate. MTC asked BRW to respond to these points and BRW's response is contained in **Attachment 5**.

In its letters of 28 February 2003 and 17 March 2003, MTC responded to issues associated with the inclusion in the alternative projects of:

- phase-shifting device to control power flows;
- tactical undergrounding; and
- P75 contingency allowances.

[10] BRW's report "*TransÈnergie-Murraylink: Selection and Assessment of Alternatives*" dated 16 October 2002 was included as Appendix F of the MTC Application.
[11] The Allen Consulting Group, April 2003, *Commentary on Economic Issues* (Attachment 1), pp. 11-6.
[12] MTC assumes that the "Optimised Depreciated Replacement Cost" valuation process is the same as the DORC valuation process.

Several submissions suggested that the capital cost of SNI stated in NEMMCO's *Determination Under Clause 5.6.6 of the Code: SNI Option*[13] ("**NEMMCO's Determination**") can be used to derive an upper limit for Murraylink's regulatory asset value. BRW explains in its response (in Attachment 5) the significant technical and service level differences between SNI and Murraylink. Given these substantial differences, neither SNI nor the interconnector portion of SNI qualifies as an alternative project for the purpose of valuing Murraylink. In addition, in view of stakeholder perceptions as to the cost of SNI, MTC sought from BRW a current estimate of the actual capital cost and on-going maintenance cost of the SNI Option as defined in NEMMCO's Determination. This estimate is contained in **Attachment 6**.

In preparing the cost estimate for SNI, BRW relied upon the project scope detailed in the NEMMCO's Determination. This information was not conclusive as to the precise scope of SNI, and BRW have made reasonable assumptions where necessary. MTC and BRW accept that this costing may be refined as more precise information becomes available.

Based on the publicly available information, BRW estimate that the present value of SNI's capital cost would be significantly greater than \$110 million.

In the absence of precise scope information, and given the substantial difference in the technical service provided by SNI and Murraylink, it is not possible for stakeholders to make a direct comparison between the cost of SNI and the cost of Murraylink's alternative projects.

BRW have taken into account the extent to which a project similar to SNI could provide the same level of technical service and market benefits as Murraylink by selecting and assessing its Alternative 1 project.

9. Regulatory Control Period

Stakeholders have commented on length of MTC's proposed regulatory control period. MTC continues to believe that a regulatory control period of 10 years is justified given the high initial and on-going efficiency of MTP's operation and maintenance practices, the absence of forecast capital expenditure, and the substantial cost savings to the Commission, the NEM participants and MTP associated with deferring the next regulatory review process until at least 2012. MTC also believes a regulatory period of 10 years provides a reasonable level of certainty that encourages private sector investment and attracts new entrants to the NEM.

At this point, MTC proposes that the Commission even consider a regulatory control period of 20 years with a mechanism that would enable the Commission or MTC to trigger a regulatory review at 10 or at 15 years from the start of the period. This longer period would not reduce the Commission's discretion to review Murraylink's asset value and revenue at 10 or at 15 years while preserving the Commission's discretion to extend the regulatory control period to up to 20 years if the Commission believed that there would be little net benefit in a regulatory review at an earlier time. And the longer period would provide a positive signal to investors that the Commission is willing to provide a good level of certainty where it can.

[13] NEMMCO, December 2001, *Determination Under Clause 5.6.6 of the Code: SNI Option*, p. 3.

Some stakeholders suggested that the Commission should reserve its right to initiate a review of Murraylink's regulatory asset value at any time during MTC's regulatory control period upon the occasion when a project, which could provide a service similar to that of Murraylink but that is not yet committed[14], is built. These stakeholders have suggested that, as a consequence, Murraylink's regulatory asset value would be written down. MTC believes that for the Commission to reserve such a right would contravene sound regulatory practice and be highly inconsistent with Commission's current and stated regulatory intent. It would have the potential to create a grossly inefficient market outcome and to severely undermine investor confidence in the NEM as a whole.

10. Proposed Pass-Through Rules

In section 7.3 of its Application, MTC indicated that it had endeavoured to identify all the efficient costs associated with the provision of Murraylink's prescribed service, including the procurement of appropriate insurance. However, events could occur that are outside of MTC or MTP's control and that could substantially change MTP's costs and/or the value of its regulatory asset base. MTC also indicated that it would lodge a supplementary application setting out the pass through rules that may be appropriate for Murraylink. This section of our letter constitutes that supplementary application and MTC's proposed pass through rules are contained in **Attachment 7**.

In putting forward these pass through rules, MTC acknowledges the views of stakeholders and the Commission that the pass through rules should allow for symmetrical pass through and other matters described in s. 5.7.5 of Commission's *Decision: Victorian Transmission Network Revenue Caps 2003-2008* of 11 December 2002.

MTC's proposed pass through rules also reflect MTC's circumstances. In particular, its proposed relationship with Coordinating Network Service Providers and its material exposure to events associated with requirements of its connection and revenue recovery contracts and with non-contestable works over which it has no reasonable control. MTC's connection and revenue recovery contracts are critical to its viability, have the potential to impose significant charges and MTC's bargaining power in relation to the terms of the contracts is limited.

As a regulated entity, MTC may be required pursuant to these agreements to carry out non-contestable capital works and MTC seeks a mechanism to allow the related investment and costs to be recognised in its regulatory asset base and revenue cap. However, given the early stage in its negotiations with Coordinating Network Services Providers, MTC is unable at this stage to provide a detailed basis for determining the value or pricing of these works. Accordingly, MTC proposes to deal with non-contestable capital works in the pass-through rules.

MTC requests that the Commission incorporate its decision on MTC's pass through rules into its determination of MTC's Application of 18 October 2002.

[14] Objective criteria for project commitment contained in NEMMCO's *Statement of Opportunities for the National Electricity Market* (2002, p. 2-5).

11. Operational asset life

One stakeholder queried the asset lives of the components of Murraylink. MTP confirms that, under normal operating conditions and the maintenance plan currently budgeted in MTC's operating and maintenance budget, Murraylink's HVDC equipment is designed to have an operational asset life of 40 years.

In this submission, MTC has addressed what it believes to be the material issues raised by stakeholders. As always, we would be pleased to provide further information in relation to any of these issues or any other matter raised by stakeholders that the Commission believes has a bearing on its determination of MTC's application.

Yours sincerely

Stéphane Mailhot
Chief Executive Officer
Murraylink Transmission Company

Attachments

1. The Allen Consulting Group - Commentary on economic issues
2. Deloitte Touche Tohmatsu – Commercial discount rate
3. TransÉnergie US - Further comments on its calculation of Murraylink's reliability benefits and other modelling issues
4. TransÉnergie US – Treatment of Murraylink losses
5. Burns and Roe Worley – Response to stakeholder submissions
6. Burns and Roe Worley – Independent costing of SNI
7. Pass Through Rules

April 2003

Report to Murraylink Transmission Company

Application for Conversion of Murraylink to a Prescribed Service

Commentary on the Economic Issues

The Allen Consulting Group

The Allen Consulting Group Pty Ltd

ACN 007 061 930

Melbourne

4th Floor, 128 Exhibition St

Melbourne Victoria 3000

Telephone: (61-3) 9654 3800

Facsimile: (61-3) 9654 6363

Sydney

3rd Floor, Fairfax House, 19 Pitt St

Sydney New South Wales 2000

Telephone: (61-2) 9247 2466

Facsimile: (61-2) 9247 2455

Canberra

Level 12, 15 London Circuit

Canberra ACT 2600

Telephone: (61-2) 6230 0185

Facsimile: (61-2) 6230 0149

Perth

Level 25, 44 St George's Tce

Perth WA 6000

Telephone: (61-8) 9221 9911

Facsimile: (61-8) 9221 9922

Online

Email: allcon@allenconsult.com.au

Website: www.allenconsult.com.au

Table of Contents

1. Introduction and Overview

The Allen Consulting Group has been engaged by Murraylink Transmission Company (MTC) to provide commentary on the economic issues that were raised in the submissions from interested parties to MTC's application for the services provided by the Murraylink project to be converted to a prescribed service,[1] and for the maximum allowable revenue for those services to be determined. The report was prepared by Jeff Balchin, Director, from the Group's infrastructure regulation practice.

The most important of the economic issues raised in submissions relate to the determination of a regulatory value for Murraylink on its conversion to a regulated interconnector. MTC applied the 'optimised deprival value' methodology (ODV) to determine the regulatory value for the Murraylink asset, consistent with Chapter 6 of the National Electricity Code, the Australian Competition and Consumer Commission's draft Statement of Regulatory Principles, and the Commission's statements about how it would set the regulatory value for an interconnector that converts into a regulated interconnector.

A major concern expressed in submissions with the valuation methodology employed for the Murraylink asset was that an ODV methodology is not the most appropriate methodology for deriving the regulatory asset value of an interconnector that is converting to a regulated interconnector. Instead, it was argued that the regulatory value for such a project should – in effect – be set such that all market participants would be made better off as a result of the conversion.[2] This valuation methodology is referred to below as the 'incremental benefits' valuation methodology.

An implicit assumption in the suggested use of the 'incremental benefits' valuation methodology is that the Commission is starting with a 'clean sheet of paper' and that any asset value the Commission assigns is equally valid and – as the Murraylink asset is sunk – has no implications for economic efficiency.

In contrast, as noted already above, the Commission has made a number of statements about the method it would apply to determine the regulatory value of electricity transmission assets in general, as well as specific statements about how it would derive a value for an interconnector that converted from a market network service to a regulated interconnector. One of the purposes of such statements is to provide investors with the degree of certainty about future regulatory decisions required to attract capital into the industry – the future regulatory valuation of assets of key importance. In the face of such commitments, it is not valid for these submitters to assume that all options are open and that there are no efficiency implications associated with alternative asset valuation methodologies.[3] This matter is discussed in section 2.

In addition, when analysed further, the 'incremental benefits' asset valuation methodology is also found to have implications that are unreasonable to the owners of Murraylink, and may also undermine the rationale for permitting a conversion of an interconnector into a regulated interconnector. This matter is discussed in section 3.

---

1 The terms 'prescribed service' and 'regulated interconnector' are used interchangeably in this report.

2 NERA, Comments on Murraylink's Application for Conversion to Regulated Status, January 2003, p.10.

3 As noted in section 2, the Commission has been careful to acknowledge its previous statements on this matter.

Regarding the asset valuation methodology applied by MTC, the most important of the criticisms was that the valuation methodology adopted by MTC was inconsistent with the Commission's 'regulatory test'.[4] At least three reasons were provided for this inconsistency, which were that:

- only the cost of alternative projects were considered, rather than the benefits – and in particular, the relative net benefits of alternative projects;
- related to the previous point, it was argued that the alternative projects to Murraylink were defined too tightly, which precluded analysis of similar (but not identical) options and possibly included 'gold-plating'; and
- sufficient market development scenarios were not analysed when calculating the market benefits created by Murraylink.

A threshold issue for the Commission that is raised by these comments is whether all of the parallels with the conduct of the 'regulatory test' necessarily are relevant – or appropriate – to the determination of asset values for regulatory purposes. Any methodology for valuing assets – and revaluing assets over time – needs to achieve predictability of operation, as well as a reasonable degree of administrative cost. The types of analysis required to satisfy the criticisms summarised above would imply a degree of subjectivity – and new analysis – that would be unlikely to satisfy either of these objectives. This matter is discussed in section 4.

Lastly, a concern at the centre of many of the comments of market participants – or their representatives – was that Murraylink's conversion could lead to market participants 'paying twice' (through regulated transmission use of system charges) for part or all of the service potential that is created by Murraylink. Market participants can form their own views about whether such duplication is likely to occur in practice. However, even should such duplication occur, whether the costs recovered from market participants (through TUOS charges) increase as a result would depend upon how the Commission applies a ODV valuation to assets that – in combination – are excess to requirements. This matter is discussed in section 5.

Section 6 then comments on a number of miscellaneous regulatory issues, which include:

- *the 'commercial discount rate'* – out of the alternative 'commercial discount rates' that have been proposed, the estimate used by MTC appears to have been the only one derived from objective capital market information, which is the information relevant to cost of capital estimation; and
- *the assumptions reflected in the regulatory WACC for Murraylink and regulatory period* – consistency with its previous regulatory decisions would imply the Commission using a 10 year bond rate as the risk free rate (reflecting the length of the regulatory period), and the merits (and provisos) identified in the NERA submission with the use of a 10 year regulatory period are supported.[5]

[4] Australian Competition and Consumer Commission, Regulatory Test for New Interconnectors and Network Augmentations, December 1999.

[5] NERA, op cit, p.26.

As noted above, this report focuses on the main economic issues that were raised in submissions on MTC's application. A number of comments have been made in submissions on the detailed implementation of the ODV asset valuation methodology to Murraylink, including on the cost of alternative projects and related matters like the extent of undergrounding required, the assumptions reflected in MTC's modelling of the market benefits of Murraylink as well as on technical matters, such as the expected power flows from the use of the Murraylink asset and the appropriate reliability targets. It is understood that these matters either have been – or will be – addressed in other submissions by MTC, and are not the subject of this report.

2. Guiding Principles for Asset Valuation

2.1 Efficiency and Asset Valuation

An overarching objective of all of the reforms to Australia's utility industries under the broad framework of national competition policy is the promotion of economic efficiency. Indeed, in its recent report on the operation of Part IIIA of the *Trade Practices Act 1974* (the 'national' access regime), the Productivity Commission recommended that the relevant legislation be amended to clarify that economic efficiency is the primary objective. The Commission itself has recognised the importance of economic efficiency as the guide for regulatory decisions, a position it has taken consistently across all industries.

Economic analysis takes as given that we have only limited resources available, and the goal of an economy – economic efficiency – is to use those limited resources in a manner that maximises the net benefit to society. While there are a number facets of economic efficiency – which include that only goods and services sought by customers are produced, that they are produced for least cost, and that these conditions continue to be met over time in the face of changing tastes and technology – the underlying requirement is that an economy makes best use of the resources it has. Applied to Murraylink – given this asset already exists (and cannot be reversed), the relevant objective is to use it in a manner that maximises economic efficiency.

A relevant question for the Commission – and one not expressly addressed in the submissions to MTC's application – is whether its conversion (and the terms of that conversion) from a market network service to a regulated interconnector would advance economic efficiency – that is, whether its conversion (and the terms of that conversion) would be good for the economy overall.

When analysed objectively, it is difficult to see how Murraylink's conversion to a regulated service could reduce economic efficiency, and indeed the arguments made in related matters would suggest that Murraylink's conversion may provide substantial efficiency improvements. There are two routes through which efficiency may be advanced.

First, it has been argued that, when operated as a market network service, MTC may have an incentive to withhold part of Murraylink's capacity.[6] If true, then in times of constraint between regions, more expensive generation than required would be used, and a loss of efficiency would result. While MTC disputes the magnitude of this incentive – and no independent view of this matter is provided here – its conversion to a regulated interconnector would remove any incentive or ability to withhold its capacity from the market, and so preclude any such inefficiency.

[6] MTC's (or any other MNSP's) incentives with respect to the withholding of capacity are complex, and not independent of the regulatory framework within which they operate. To the extent that an MNSP negotiates hedging contracts with other market participants, it would have an incentive to place the corresponding amount of capacity onto the market (at least in the circumstances where withholding capacity may affect efficiency). However, its ability to sign hedging contracts with other market participants is dependent upon those other participants' expectations about future price differentials between regions, which in turn are dependent upon expectations of the implications of the regulatory arrangements for new developments between regions (in particular, the application of the 'regulatory test').

Secondly, operating Murraylink on an open access basis may also provide for a more certain environment for the planning of the national electricity grid. This reflects the fact that all of Murraylink's capacity (subject to the relevant power system constraints) would be available for the independent operator to use in a manner consistent with the solution to the (known) system optimisation algorithms, rather than the available capacity being determined by MTC's bidding behaviour. Indeed, the arguments of other parties to other related matters would suggest that Murraylink's conversion to a prescribed service may remove a barrier to efficient investment proceeding.

- The National Electricity Tribunal summarised TransGrid's concern about the commercial feasibility of the unbundled SNI project (USNI) as follows:[7]

> TransGrid's reason for not undertaking USNI is that it would lead to a risk of "asset stranding". It has declined to be a proponent. Its stated fear is that Murraylink, as an unregulated interconnector undertaking its activities by way of arbitrage, might so conduct itself that TransGrid's investment in USNI could become stranded. It contends that USNI would be dependent on the flow of power over Murraylink, and that Murraylink would have the capacity and the financial incentive to withhold flow, which would have as a consequence the possible stranding of USNI.

- This perceived 'stranded asset risk' – and hence TransGrid's concerns about the commercial viability of the more efficient unbundled SNI project – presumably would disappear with Murraylink's conversion from a market network service to a regulated interconnector.

Accordingly, the conversion of Murraylink to a regulated interconnector may enhance efficiency, and potentially enhance efficiency substantially, if the arguments that other parties have made in related proceedings are correct. These efficiency benefits would flow irrespective of the terms of Murraylink's conversion (that is, irrespective of its regulatory asset value). The main issues of contention with the MTC application, therefore, come down to the distribution of the benefits that are provided by the Murraylink interconnector between MTC and other market participants.

If *static efficiency* alone is considered, the distribution of the benefits of Murraylink – to a large extent – is unlikely to affect efficiency. That is, they relate to transfers between the respective parties, the 'sharing of the cake' rather than the 'size of the cake'. However, the valuation methodology adopted by the Commission is likely to have implications for dynamic efficiency, which is discussed below.

2.2 The Importance of Acting Reasonably and Adhering to Commitments

As the Commission is well aware, potential investors in irreversible investments make decisions based upon perceptions of future regulatory decisions, and objectives such as 'fairness' or 'reasonableness of treatment' – which have little to do with *static* efficiency – can have a profound impact on new investment, and hence with the achievement of economic efficiency over time. Indeed, the Commission explicitly recognised the implications for dynamic efficiency of acting reasonably in its very first consideration of regulatory asset valuation for energy utilities, where it commented as follows:[8]

[7] *In the Matter of an Application for Review of a NEMMCO Determination on the SNI Interconnector Dated 6 December 2001*, per Cripps and Williamson, pp.49-50.

[8] Australian Competition and Consumer Commission, Final Decision: Access Arrangements for Transmission Pipelines Australia, October 1998, p.32. The Commission referenced this discussion of asset valuation in its draft Statement of Regulatory Principles (p.x).

> This discussion [on static efficiency considerations] assumes, however, that the treatment of existing assets can be separated from the treatment of new assets. One consideration for dynamic efficiency is that the price set for existing assets may influence the expectations of investors as to the regulator's treatment of future investment. While the Victorian Access Code clearly separates the treatment of existing assets from new assets, industry participants are likely to see the regulator's treatment of existing assets as setting a precedent for how it will exercise its (generally wide) discretion when making other decisions under the Victorian Access Code in the future. Therefore, opportunistic behaviour by the regulator with respect to existing assets may dampen the incentives for investment in the industry.

One of the means that regulators use to limit the uncertainty with respect to a regulator's potential future decisions is to make statements about how they are likely to exercise that discretion. A dominant purpose of such statements is to provide the degree of confidence about future regulation – and hence future revenue – required for investors to fund large projects where the costs are (economically) sunk.[9]

The Commission has made a number of statements about the valuation of assets that are relevant to this application. The draft Statement of Regulatory Principles proposes the use of a depreciated optimised replacement cost (DORC) methodology for valuing and revaluing regulated assets together with the ability to write-down assets to below the DORC value where this exceeds its economic value.[10] These two valuation rules combined amount to what is normally referred to as an optimised deprival value methodology (ODV), consistent with clause 6.2.3(d)(4)(iv)(A) of the National Electricity Code. The Commission has noted that the same principles should apply to the determination of a regulatory asset value for an asset converting to a regulated interconnector:[11]

> The Commission will consider any applications to convert from market to prescribed status on a case by case basis. However, the *Draft Regulatory Principles* clearly set out the process that incumbent NSPs must follow at each regulatory review [for setting revenue caps] and applicants for conversion of network services to prescribed status will have to follow the same process. The Commission will develop the *Draft Regulatory Principles* to set out the process and guidelines needed to formalise the conversion arrangements.
>
> Further the *Draft Regulatory Principles* set out that a DORC valuation will be used to value (or revalue) the asset base of the NSP. The Commission considers that the DORC valuation allows for consideration of all possible options for replacing existing network services, as well as consideration of current and future utilisation rates. The effect of a DORC valuation will be that the network is valued to reflect the least cost solution to resolve any demand and supply imbalance needing to be addressed. Thus the process of changing status of network services requires the NSP to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test. The processes set out in the *Draft Regulatory Principles* may be simpler than the regulatory test processes but the Commission considers that no material advantage will accrue to NSPs converting from market to prescribed status through bypass of the regulatory test.

---

[9] The term 'sunk cost' implies that the related asset has no practicable alternative use. In such a situation, it is not possible for the asset owner to withdraw the physical asset from one activity and use it in another if the profitability of the first activity falls.

[10] Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, Proposed Statements S4.2 and S4.3, p.53.

[11] Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138.

It is reasonable to interpret this statement as confirming that the Commission would apply the same process and rules for setting revenue caps – and most importantly for the matter at hand, for deriving regulatory asset values – to all regulated networks, irrespective of whether the relevant network was an existing regulated network, or the revenue caps were being determined in the context of an asset converting to a regulated asset. The additional guidance the Commission provided was that it considered that a DORC valuation methodology would be consistent with the application of the regulatory test for prospective new projects.[12]

As discussed in section 4 below, the Commission's statement about the equivalence of the regulatory test and ODV is true, provided the *economic value* constraint in the ODV valuation is calculated in a manner consistent with the calculation of market benefits in the regulatory test. The asset valuation methodology adopted by MTC has adopted *market benefits* calculated in accordance with the 'regulatory test' as the measure of the economic value of the Murraylink asset, reflecting the intent of the Commission.

The Commission's Issues Paper on the MTC application demonstrates its awareness of the statements and reasonable expectations that it has made regarding the setting of revenue caps in general and the regulation of interconnectors converting to regulated assets in particular, and implicitly of the importance of acting in a manner that is consistent with its previous statements.[13] Moreover, in other relevant matters, the Commission has been careful to act in accordance with its previous statements in circumstances where it is reasonable for those statements to have been acted upon.

The alternative asset valuation methodology that has been proposed – that is, to determine the value for Murraylink such that all market participants benefit from its conversion to a regulated interconnector – is not consistent with the previous guidance the Commission has provided on this matter. As the Commission has provided guidance as to how it would deal with interconnectors that convert to regulated interconnectors – long term efficiency considerations dictate that its previous guidance should be applied, and the ODV methodology applied to determine the regulatory value for the Murraylink asset.

Irrespective of the Commission's previous commitments, however, it is considered that there are a number of weaknesses with the proposed alternative valuation methodology. These issues are addressed in section 3 below. First, however, a number of comments about the rational for permitting an MNSP to convert to a regulated interconnector are addressed.

2.3 Rationale for the NEC Conversion Provisions

A number of submissions have implied that it is undesirable for the Commission to permit the Murraylink asset to convert to a regulated interconnector as this would permit it to escape from the commercial risk that it took when it committed to the project. TransGrid comments that:[14]

> [t]he conversion process should not under any circumstances be allowed to be used merely to bail out bad commercial decisions.

---

[12] It is assumed in this discussion that the Commission intended to apply the ODV methodology to converting interconnectors – that is, to retain the discretion to value assets at less than DORC if the economic value constraint was met – reflecting its proposed treatment of other regulated assets.

[13] Australian Competition and Consumer Commission, Issues Paper: Murraylink Transmission Partnership – Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue, February 2003.

[14] TransGrid, Murraylink Transmission Company Application for Conversion of Murraylink to Prescribed Services, March 2003, p.1.

The ability for a market network service to convert to a regulated interconnector – including the reference to the Chapter 6 revenue setting principles – was included in the National Electricity Code prior to Murraylink's construction, and the Commission's statements as to how it would apply Chapter 6 to value assets in general already had been made. It is reasonable to expect that MTC's assessment of the commercial viability of the Murraylink investment took account of the 'escape clause' in the NEC, and that the existence of the clause influenced its decisions of whether to proceed with the project. Accordingly, it is difficult to maintain that the 'escape clause' in clause 2.5.2 of the NEC is being used by MTC in a manner that was not envisaged when the relevant clause was inserted in the NEC.

A more general question is whether such an 'escape clause' as exists in clause 2.5.2 is appropriate.

The ability for a market network service provider to capture the market benefits that it provides to the market – and hence the profitably of these projects – depends critically on both the efficiency of the NEC provisions and the administration of those provisions. Indeed, it is difficult to imagine any other activities for which the design and administration of the market and regulatory arrangements can have a greater effect on a project's viability. Without some protection against unfavourable regulatory developments that affect their ability to capture the benefits created, it may well be that investment in unregulated interconnectors would seldom be financially viable. Indeed, the dependence of the ability of MNSPs to capture the benefits they create on the efficiency of the national electricity market was recognised by the NECA Working Group that developed the 'safe harbour' provisions for MNSPs:[15]

> As already noted, the concept of a non-regulated interconnector is still somewhat experimental. It might be argued that as well as the usual commercial risks, the proponent of a non-regulated interconnector may face additional risks related to market design deficiencies that may only become apparent once the first interconnectors are operational.
>
> Providing a right to apply for regulated status may help ensure that investment is not inefficiently inhibited by such non-commercial market design risks. However it is important that the conversion option should not shield the proponent from normal commercial risks, e.g. the risk of having over-judged the future demand for the interconnection service. It is therefore essential that the regulated revenue entitlement is based on the assessed need for the facility at the time of the application, rather than guaranteeing a return on the original capital cost.

In light of these concerns, the Working Group's recommendation was that the 'safe harbour' provisions to be inserted in the National Electricity Code be drafted so that '[t]he interconnect owner can apply to convert to regulated status at any time'.[16]

The administration of the relevant market rules – as well as the rules themselves – can have a substantial impact on a project's viability. Clearly, an important factor that will affect the viability of any MNSP is the application of the 'regulatory test', which remains subject to substantial uncertainty. Moreover, uncertainty with respect to the 'regulatory test' may affect an MNSP's ability to extract the benefits it creates well before any duplication occurs as this uncertainty will affect the propensity for participants to sign contracts for the benefits they receive.

---

[15] NECA Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors, Entrepreneurial Interconnectors: Safe Harbour Provisions, November 1998, p.9.

[16] NECA Working Group on Inter-regional Hedges and Entrepreneurial Interconnectors, Entrepreneurial Interconnectors: Safe Harbour Provisions, November 1998, p.9.

It is also possible that investors may make decisions based upon assumptions that the relevant market rules would change – and in particular, that changes that enhance economic efficiency – would be made. There are also a number of improvements to the national electricity market rules that a reasonable person may have expected to have occurred, and which would affect the capacity of MNSP's to capture the benefits that they create. These include:

- *Value of Lost Load (VOLL)* – NECA's recommendation to increase VOLL to $20,000 has not been implemented, notwithstanding the Commission's acceptance that such a value would be more efficient. The lower VOLL constrains the value of the services MNSP's provide to below efficient levels.
- *Nodal pricing* – despite numerous recommendations for the increasing the locational signals in the market, there has been little movement in this direction.
- *Settlements* – while prices are calculated in the national electricity market for each five minute interval settlement is conducted for 30 minute time intervals, with the prices calculated as a simple average of the five minute prices. In addition, settlements assume that flow along interconnectors proceeds in only on direction during the 30 minute settlement period, whereas energy can flow in both directions during this period. Both of these rules reduce the efficiency of pricing in the national electricity market – and limit the extent to which MNSP's can capture the benefits that they create.

Given the risk associated with changes to the national electricity market rules, failures to change the rules as expected, and with the administration of those rules, it is not unreasonable for an 'escape clause' to exist for MNSP's. Indeed, without such a clause, it may well be that such investments could not be justified.

3. Application of the 'Incremental Benefits' Asset Valuation Methodology

As discussed above, it is considered that the 'incremental benefits' valuation methodology – as described in the NERA submission and reflected in other submissions – is not the correct methodology to apply to determine the regulatory asset value for the Murraylink asset. The Commission described the manner in which it would value assets converting from market network services to prescribed services in its draft Statement of Regulatory Principles – which reflects the methodology described in Chapter 6 of the National Electricity Code – and upon which expectations, substantial investments have been committed. As the ACCC is well aware, resiling from commitments that it has given – and given for the sole purpose of providing investors with guidance about how the Commission will exercise its discretion in the future – is unlikely to promote economic efficiency or any of the other objectives of the national market.

Even if the Commission's assessment of the MTC application was not guided by the relevant legislation and the Commission's own statements on the matter, however, it is not clear that significant weight should be accorded the 'incremental benefits' methodology.

On the face of it, the 'incremental benefits' valuation methodology has some appeal – it would ensure that other market participants could not be made worse off (as a group) as a result of the conversion of a market network service into a prescribed service. Although, as always, some individual market participants could be made worse off, provided that others were made correspondingly better off. When analysed more closely, however, it is patently unreasonable.

The formula for the 'incremental benefits' methodology implies a regulatory cost for the prescribed services consistent with the minimum between:

- the lifecycle capital and operating cost of Murraylink; or
- the expected revenue from Murraylink if it continued to act as an MNSP (denoted below as Revenue [MNSP]) <u>plus</u> the net market benefit associated with Murraylink's conversion to a regulated interconnector.

The first constraint is identical to that proposed by MTC, as discussed above. The relevant constraint for the purposes of this discussion is the second – and will provide a different answer to a standard DORC/ODV methodology to the extent that the amount calculated under this constraint differs to the gross market benefit provided by Murraylink.

The *net market benefit* associated with Murraylink's conversion from an MNSP to a regulated interconnector is simply the difference between:[17]

- the market benefit provided by Murraylink as a regulated interconnector (denoted below as Benefit [Reg]); and
- the market benefit provided by Murraylink as an MNSP (denoted below as Benefit [MNSP]).

[17] It is assumed for the purpose of this discussion that the incremental cost of converting from MNSP to regulated interconnector is negligible.

Accordingly, the second constraint of the 'incremental benefits' valuation methodology can be expressed as:

- *Regulatory Cost* = *Revenue [MNSP] + Benefit [Reg] – Benefit [MNSP]*
  = *Benefit [Reg] – (Benefit [MNSP] – Revenue [MNSP])*

The first of the terms in the expression above is the constraint imposed by the ODV methodology, as discussed above. Accordingly, an implication of the 'incremental benefits' methodology is that the regulatory cost for Murraylink would be set at the ODV, *minus* the benefits that Murraylink creates as an MNSP that it is unable to capture (as revenue). That is, the ODV would be adjusted downwards by the amount of benefits created by Murraylink as an MNSP that other market participants are able to enjoy at no cost (that is, the benefits that they are able to 'free ride' upon).

When expressed in this way, it is difficult to argue that the 'incremental benefits' valuation methodology that is advanced in the submissions results in a regulatory cost for Murraylink that could be considered reasonable.

The justification for an 'escape clause' for an MNSP stems from the fact that the rules for the national electricity market and their administration have a profound effect on the capacity of MNSP to capture the benefits that they create. The purpose of the 'escape clause' is to provide the ability to convert to a regulated interconnector should either the rules – or the administration of the rules – change or fail to change as expected and so affect the extent to which the benefits created can be captured.

Against this background, it would appear counter-intuitive to set a regulatory value for a converting MNSP which had the effect of compensating it for *all* of the market benefits it creates *except* for those it was unable to capture as an MNSP.

More generally, the 'incremental benefits' valuation methodology has the effect of giving market participants a right to continue to receive for free benefits that technically they are 'free-riding' upon.[18] While the parties (and their representatives) who receive benefits at no cost would be expected to support the continuation of such a situation, there is no strong economic or public policy reason for preserving the status quo. Rather, the appropriate response in the face of a market failure such as 'free-riding' is to seek to correct that market failure – or to apply any rules that were put in place to address such a market failure should it arise. Clause 5.2.5 of the National Electricity Code and the Commission's statements in the draft Statement of Regulatory Principles were designed to deal with this potential for free-riding, and should be applied.

[18] 'Free riding' refers to the situation whereby agents cannot be excluded from consuming the relevant good or service (referred to as non-excludable) and so are able to receive the good or service without paying for it (insert ref). Goods or services from which agents cannot be excluded (such as national defence) are unlikely to be provided (or provided in optimal quantities) in a market, and some form of government intervention may be justified.

4. Application of the ODV Asset Valuation Methodology

4.1 MTC's Asset Valuation Methodology

Consistent with the Commission's guidance on the matter, MTC has adopted an optimised deprival value (ODV) methodology for deriving a regulatory value for the Murraylink asset. Under ODV, the regulatory value of an asset would be defined as the lesser of:

- the *depreciated optimised replacement cost* (DORC) of the asset; and
- the *economic value* of the asset.

As the Commission has noted previously, the derivation of the *economic value* of an asset – and the use of that value as a regulatory value – can be problematic, given that the regulatory settings determine the value of an asset to its owner, implying a degree of circularity.[19] However, in its application, MTC has broken the circularity by defining economic value in a manner consistent with the estimation of market benefits under the Commission's 'regulatory test'. As discussed further below, this definition of economic value also creates consistency between the Commission's 'regulatory test' and the valuation and ongoing re-valuation of regulated assets, consistent with the intent of the Commission.[20]

In contrast, the objective of a DORC valuation of an asset is well-defined – at least in theory. In principle, a DORC valuation seeks to estimate the maximum price that a person would be willing to pay for an asset against the alternative of constructing a new asset – in effect, an estimate of the price that an asset would sell for if that asset was traded in a liquid second-hand market (like used cars). Accordingly, the value of the old asset would reflect the cost of the new – and optimum – asset, adjusted to reflect differences between the old asset and the new asset (for example, to reflect higher maintenance and renewals capital expenditure of old assets, differences in service potential, etc).[21] In practice, however, a number of administrative simplifications are reflected in DORC valuations – and for good reason, as discussed below.

The dominant criticism of the asset valuation methodology employed by MTC was that it was inconsistent with the Commission's 'regulatory test'. Three specific concerns were raised, which were that:

- only the cost of alternative projects were considered, rather than the benefits – and in particular, the relative net benefits of alternative projects;
- related to the previous point, it was argued that the alternative projects to Murraylink were defined too tightly, which precluded analysis of similar (but not identical) options; and

---

[19] Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, p.39.

[20] Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138.

[21] The Commission has discussed the theoretical foundations of the DORC valuation in similar terms: Australian Competition and Consumer Commission, Draft Statement of Principles for the Regulation of Transmission Revenues, May 1999, pp.39-40.

- sufficient market development scenarios were not analysed when estimating the market benefits created by Murraylink.

On a related matter, it was also suggested that the asset value included costs in respect of 'non-prescribed services', which should be removed.

A threshold issue for the Commission is the extent to which it is appropriate for the lessons from the application of the 'regulatory test' to be carried over into the Commission's approach to valuing – and re-valuing – assets in the context of periodic revenue cap reviews. This issue is discussed first, followed by the specific criticisms of the MTC asset valuation methodology.

4.2 Regulatory Test vs Asset Valuation (and Re-Valuation)

It is important to understand the specific – and different – contexts of the application of the 'regulatory test' and the valuation and re-valuation of assets for regulatory purposes.

- The 'regulatory test' is applied at a time prior to investment being undertaken (and expenditure sunk). The objective of the 'regulatory test' is to rank the desirability of a particular project against possible alternatives (including the alternative of doing nothing, or doing the same thing at a different time), and the particular project need not rank ahead of alternatives in all of the future scenarios modelled. The benefits and costs assumed in the application of the test have no continuing relevance after the conduct of the test – the value of the new asset will be set at its DORC value (which should reflect its actual cost in the first instance) and then get re-valued at DORC over time.

- Asset valuation methodologies are applied – and reapplied over time – to assign a regulatory value for the relevant network asset. This regulatory value, in term, is used as an input to derive the revenue that the network service provider is permitted to receive from the sale of the services provided by means of that asset. A substantial portion of the allowed revenue for transmission assets reflects capital related costs (typically in excess of 70 per cent), of which the regulatory value is a key input. Investors will only be willing to devote their funds to these projects if the expected return over the life of the project (taking account of the regulator's future decisions) exceeds their required returns.

For the application of the 'regulatory test, it is appropriate that the widest set of alternative options and market development scenarios be considered, given that all options at that stage – literally – are open, and because the only result required of the analysis is either a 'yes – the project passes the test' or 'no – the project does not pass the test'.

In contrast, the methodology that is used to assign a value to assets for regulatory purposes will have a significant effect on the returns available to investors, and hence the expectations about how assets will be re-valued in the future are likely to have a significant effect on the preparedness of investors to devote their funds to the regulated activity. Given the importance of the future asset valuation methodology to investors, it is imperative that the outcomes of that methodology have a degree of *predictability of operation*.

In addition, the Commission has foreshadowed that it may re-set the regulatory value of assets at each revenue cap review, which have typically been at intervals of approximately five years. Where the asset valuation is to be reapplied at such frequent intervals, there is also likely to be merit in standardising relevant aspects of the methodology to *reduce the costs of administering* the relevant methodology.

The full implications of the parallels of the 'regulatory test' for asset valuation – as discussed in the submission by NERA (and reflected in other submissions) – while arguably theoretically correct, are likely to result in an asset valuation methodology that would generate not predictability of operation and involve unreasonable cost of administration. In addition, it is not clear that the adoption of that additional analysis would change the valuation calculated in the current matter. This matter is discussed next.

4.3 Implications of the 'Regulatory Test' for Asset Valuation

Practical Implications of the 'Regulatory Test' DORC

NERA's comments about the asset valuation methodology employed by MTC are phrased in terms of whether the methodology results in a regulatory asset value that passes the 'regulatory test', noting for example:

> In order to ensure that a RAV is chosen for Murraylink such that it passes the regulatory test …

As noted above, however, the matter for the Commission is not the administration of the 'regulatory test', but the determination of a regulatory value for the Murraylink asset. That said, the comments about the consistency of MTC's valuation methodology with the 'regulatory test' can be reinterpreted as a comment on how MTC has applied ODV to its asset.

The key concern that submitters expressed with MTC's asset valuation methodology is that it failed to consider similar – but not identical – projects, and also failed to consider the market benefits of the alternative (similar) projects as well as the costs. It was noted that the 'regulatory test' requires attention to be focussed on 'net market benefits'.[22]

These considerations are equally valid when considering how to apply a DORC valuation methodology in a manner consistent with its theoretical foundations. When the notional purchaser is considering buying the second-hand (sunk) asset, they would be expected to take account of the price – as well as service potential – of similar but not identical assets.

- If there was an alternative asset that cost more than a 'standard' asset – but generated benefits that exceeded the extra cost – then the price the notional purchaser would be prepared to pay for the standard asset would be lower than had the alternative (higher service) asset not existed. The price of the standard asset would fall by the difference between the incremental benefits and incremental cost associated with obtaining the higher service asset. This reduction in the price the notional purchaser would be prepared to pay for the existing asset would reflect the fact that the standard service asset implies that the net benefits associated with buying the higher service asset are sacrificed.

[22] As noted below, MTC was careful to select projects that delivered the same service potential, and so it would be reasonable to assume that the benefits from the alternatives are similar.

- Stated alternatively, the optimum replacement for a particular asset may be one that has a higher level of service potential – which, in theory at least, should be taken into account when deriving the DORC estimate.

The numerical implications of the 'theoretically correct' DORC valuation described above are identical to those derived by NERA in its discussion of the 'regulatory test'.[23] Where the optimum replacement for the current project is one that provides a different level of benefit – for example, a 'higher benefit' project is optimal – the DORC value for the existing asset would be calculated as:[24]

$$DORC_{Standard} = ORC_{Higher\ Service} - \Delta Benefit$$

where $\Delta Benefit$ is the difference in the benefit between the standard and higher service option.

This expression can be rearranged to yield:

$$DORC_{Standard} = ORC_{Standard} - Net\ Benefit$$

where Net Benefit is the change in net benefit from moving from the standard service asset to the higher service asset, which is the difference between the incremental benefits and incremental costs associated with the change in service.

The second of the above formulae is consistent with the formulae employed by NERA.[25]

Before endorsing the refined DORC valuation approach implied by the discussion above for the valuation of transmission network assets, however, the Commission needs to understand the full implications of the change in methodology.

The standard approach to DORC valuation – as applied by MTC – is to fix the level of service required and to derive an estimate of the efficient cost of replacing that service element using current technology.[26] The optimisation step normally takes as given the existing network architecture, and merely asks whether a lower capacity network asset would suffice to meet current demand (for example, this may involve asking whether the demand served by a transmission line rated to 500 kV could be met with a transmission line rated to 330 kV).

In contrast, the application of the service-adjusted DORC valuation would require far more analysis.

---

[23] NERA, op cit, pp.3-4. This equivalence between the implications of the 'regulatory test' as derived by NERA and the 'theoretically correct' DORC valuation as discussed above implies that the Commission's intuition that the regulatory test and DORC valuation should produce similar results was correct (Australian Competition and Consumer Commission, Applications for Authorisation: Amendments to the National Electricity Code – Network pricing and Market Network Service Providers, September 2001, p.138).

[24] It is assumed here that the only role for the 'depreciation' step of the DORC valuation is to adjust for the difference in the net benefits associated with alternatives with different service potential. In practice, the 'depreciation' step also adjusts for the difference in the forward-looking cost of operating the old asset compared to the optimal replacement.

[25] NERA, op cit, p.4, table 2.3.

[26] A number of other simplifying assumptions are also typically made when applying the DORC valuation methodology in practice. As an example, as noted in footnote 22, one role of the 'depreciation' step in the DORC valuation is to allow for differences between the forward-looking cost of operating, maintaining and replacing the 'old' (ie existing) asset compared to that of a 'new' asset (in discounted terms). Notwithstanding the theory, it has become standard practice merely to apply straight-line depreciation to the ORC value to derive the estimate of DORC.

- First, all alternatives for providing some or all of the existing service potential *of each network element* would need to be identified and costed (that is, the class of *similar* but not necessarily *equivalent* projects).
- Secondly, the market benefits associated with all of the different options for each of the network elements would need to be estimated (and with a number of market development scenarios run to ensure that the estimated benefits were robust).
- Thirdly, a comparison of the benefits and costs associated with the various alternatives would find the project that was the optimal replacement for the current asset (which is equivalent to the asset that maximises the 'net market benefits'). The service-adjusted DORC would then be calculated using either of the equations – so that if the optimal replacement provided a higher level of benefit than the current asset, DORC value would be adjusted downwards.

Clearly, the level of analysis required to apply the service-adjusted DORC valuation methodology is significant, and the application of such an approach *uniformly across all transmission network service providers* – consistent with the relevant Code provisions and the Commission's previous statements – would require significant resources, particularly as the analysis would need to be applied across all network elements individually. Moreover, the outcomes of such an analysis are unlikely to be predictable – particularly as the class of 'similar but not equivalent assets' is broadened. Thus, the service-adjusted DORC valuation methodology is unlikely to meet either of the objectives noted above of *predictability* and involving *reasonable administrative costs*.

We are unaware of the Commission or any other energy regulator having applied such an approach for estimating a DORC value.

A Reasonable Approximation

As noted above, the approach adopted by MTC is to decide upon and fix the level of service, and then to determine the least-cost means of providing that service potential, which follows standard practice – a point acknowledged by the Commission.[27]

As MTC has fixed the level of service potential to be provided by the asset, a reasonable assumption would be that the market benefits associated with alternative projects are similar, and thus unlikely to have a significant effect on the valuation determined. Indeed, the difficulty with quantifying the market benefits associated with different options provides a good rationale for being careful to have regard to only projects that have very similar functions when undertaking a DORC valuation.

Lastly, it needs to be noted that the relative market benefits associated with alternative projects are only relevant to the extent that those alternative projects are likely to provide 'net market benefits'. Under the ODV approach, alternative projects only affect the DORC valuation – and so a change to the DORC valuation would only affect the ODV of an asset in instances where the *economic value* constraint is not binding.

[27] Australian Competition and Consumer Commission, Issues Paper: Murraylink Transmission Partnership – Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue, February 2003, p.4.

The operative constraint on the ODV for the Murraylink asset is the economic value, rather than its estimated DORC value. Accordingly, any change to the DORC value on account of providing different levels of service would only affect the ODV to the extent that it was sufficient to change the relativity between economic value and the DORC value.

4.4 Market Development Scenarios

As noted above, MTC's ODV estimation was also criticised for not undertaking sufficient 'market development scenarios'. The assumed market development scenarios are of prime importance to MTC's estimation of the economic value associated with the Murraylink asset – although the (theoretically-correct) service-adjusted DORC value discussed in section 4.3 would also be affected by different scenarios.

It is understood that MTC has provided the Commission modelling results that are implied by the different market development scenarios, which provides an indication of the sensitivity of the estimated market benefits to different market development scenarios. This report comments only on the conceptual issue of how the Commission should use the different scenarios.

In the context of applying the 'regulatory test' – at which time no capital has been sunk and 'all options are open' – it is appropriate for a large number of market development scenarios to be tested. As discussed already, all the analysis is required to produce is an indication that a particular project is superior to all other options in most but not all cases, and a wide array of plausible scenarios – if interpreted carefully – can only assist with this decision.

However, where market benefits are calculated for the purpose of applying the ODV methodology, the output required by the analysis is a single number – not a range. To the extent that it was possible to assign the probability associated with different scenarios on an objective basis, then adding scenarios can assist – the appropriate number would be the expected (probability-weighted) value of the scenarios. In practice, however, it is unlikely that there could be any objective basis for assigning probabilities to the different scenarios, making it unclear whether expanding the number of scenarios improves the information set available.

Rather, a more robust estimate of the market benefits associated with a project – and hence the estimated economic value of the project, as required for the application of ODV – would come from undertaking only a limited number of market development scenarios – or, preferably, only one scenario – and focussing instead on the assumptions reflected in that scenario.

Moreover, if the Commission adopts the approach used by MTC to estimate the *economic value* of assets when applying the ODV to other transmission network service providers, it is likely that some form of standardisation of the calculation of economic value would be warranted. The easiest means of standardising this calculation would be for the Commission to prescribe one or a small number of market development scenarios for any particular asset revaluation.

5. Impact of Conversion on Customers and Other Market Participants

One of the key concern of market participants or their representatives is that the conversion of Murraylink to a prescribed service risks them ‘paying twice for interconnection through the Riverland corridor’.[28] An implicit assumption behind this is that a project that duplicates the service provided by Murraylink may be built and also recovered (as a prescribed service) through TUOS charges.

Whether duplicate investments occur will depend upon the decisions of the relevant network provider or providers, and participants can form their own opinions as to whether such actions will eventuate.[29]

However, even if duplication of Murraylink’s service did occur, it is not certain that customers could ‘pay twice’ for that or a similar service.[30]

To date, the Commission has not stated that it will not re-optimise an asset that passes the regulatory test. Moreover, even if the full value of an asset that passed the ‘regulatory test’ were to be reflected in TUOS charges immediately, the Commission has made it clear that it will re-optimise all investments at future reviews – irrespective of whether they historically had passed the regulatory test.

A standard application of the ODV methodology discussed above would imply that the assets reflected in the regulatory asset base for any entity would be optimised to the asset required to serve the demand. To the extent that a service was duplication – and there was insufficient demand to justify that duplication – it would be expected that value ascribed to one or both of the ‘duplicating’ assets would be written down to reflect that required for current and forecast demand.

- In the case of duplicated service potential, it would be expected that the Commission would write-down the value of the second of the assets constructed to that of an asset required to serve the incremental demand. This approach would imply that any provider who duplicated existing service potential would face substantial stranded asset risk – which would reduce the likelihood that unnecessary duplication would occur.

The effect would be that customers and other market participants would only pay once for the assets used to provide prescribed services.

---

28 ESPIC, ‘Planning Council Submission – Murraylink’s Application for Conversion’, 28 February 2003, p.6.

29 As discussed in section 2.1, concerns expressed by parties in a related matter about the uncertainty (or, more particularly, potential stranded asset risk) arising from Murraylink’s operation as a market network service would suggest that Murraylink’s conversion from a market network service to a prescribed service may remove a barrier to more efficient network investment. This reduction in uncertainty would be expected to reduce the likelihood that part or all of Murraylink’s service potential will be duplicated (at least prior to the time at which demand would be sufficient to warrant the duplication).

30 Note that it is unlikely that a duplicate project would provide all of the services provided by Murraylink, as some of the benefits it provides reflect its unique technology.

6. Other Issues

6.1 Commercial Discount Rate

A number of submissions have noted that the discount rate applied by MTC to derive the present value of its future market benefits differs from the discount rates that have been applied in other applications of the regulatory test, and in particular, that the rate used is lower than that previously applied.[31] The comments in submissions noted that use of a lower discount rate would raise the present value of the market benefits.

It would appear to be widely accepted that the discount rate should reflect the cost of capital associated with an investment in unregulated activities in the electricity supply industry (referred to as a 'commercial discount rate'), and no comment is made on this view.

While other studies have used higher discount rates than that employed by MTC when applying the regulatory test, it is not clear how those discount rates have been calculated.

The cost of capital associated with an activity is equivalent to a price that investors require to devote their investment funds to an activity. However, unlike prices for most goods and services, the cost of capital cannot simply be observed, but *can only be estimated* from the available capital market information, interpreted through a well-accepted financial model.

- The *cost of capital* associated with an activity – which is unobservable – must be distinguished from other discount rates that can be observed – such as investor hurdle rates. At best, hurdle rates reflect those investors' estimates of the cost of capital associated with the relevant activity. More likely, the hurdle rates also embody other management objectives – such as a tool for capital rationing, or for offsetting 'optimism bias' in managers – that would cause the hurdle rate to overstate the firm's estimate of the cost of capital associated with the activity.

Consistent with the discussion above, the estimate of the 'commercial discount rate' by MTC is based upon available capital market information, interpreted through a well-accepted financial model. The capital asset pricing model was used, which is probably the most widely used model for estimating costs of capital in the world. The comments in submissions have not directed the Commission to alternative and superior estimates of the cost of capital associated with the relevant activities that reflect capital market information interpreted through a well-accepted financial model.

[31] NERA (NERA, op cit, pp.17-19) also raised a number of technical issues associated with MTC's derivation of the commercial discount rate from the relevant parameter estimates. It is understood that Deloitte Touche Tohmatsu has addressed these comments in a separate report, and so these matters are not discussed here. It is also understood that the adjustments implied by NERA's comments did not have a material effect on the estimate of the commercial discount rate.

In addition, most financial models – the capital asset pricing model included – requires continuous observation of economic returns, which inevitable constrains the set of firms that can be used to estimate the cost of capital associated with a relevant activity to those listed on the stock exchange. Moreover, as there are problems with comparing information derived from capital market information across countries – the most relevant piece of information being the estimate of the equity beta – it is highly desirable that those firms that are used to estimate the cost of capital associated with the relevant activity be Australian firms.

A key feature of the Australian capital market is the recent growth in the number of energy-sector entities that are listed on the Australian Stock Exchange, both in regulated and unregulated activities. In general, as there is substantial estimation error in estimating equity betas – an input into the capital asset pricing model – the largest possible set of entities whose activities are considered comparable to the activity in question – should be used. In addition, it is generally considered that about four or five years of capital market observations are required to obtain stability in beta estimates.

The recent growth in the amount of relevant information available from the Australian capital market for estimating a commercial discount rate would suggest that the latest beta estimates of the relevant parameters would be superior – reflecting both additional entities in the set of comparable entities, and a longer time series of observations. This would suggest that historical estimates of the commercial discount rate may be less valid than more recent estimates of the commercial discount rate.

6.2 Regulatory WACC and Regulatory Period for Murraylink

In its submission, NERA offers a number of comments about the inputs that MTC has used to estimate its cost of capital for regulatory purposes (regulatory WACC). NERA notes that MTC has used a 10 year bond rate, which differs from the Commission's practice of using the yield on 5 year bond rate.[32]

NERA's comment about the Commission's practice with respect to the term of the bond that is used in the estimation of the regulatory WACC is not correct. The Commission's policy has been to align the term of the bond rate used for this purpose with the term of the regulatory period. As MTC has proposed a 10 year regulatory period, it would be consistent with the Commission's standard practice to use a 10 year bond rate as the proxy for the risk free rate.

It is noted that NERA would appear to support the use of a 10 year regulatory period rather than a 5 year period for Murraylink on the basis that the magnitude of any efficiency gains are likely to be low, and that periodic reviews impose administrative costs, subject to any cost pass-throughs being better defined and symmetric in operation.[33] We also see merit in permitting a 10 year regulatory period, and also support the provisos noted by NERA.

[32] NERA, op cit, p.24.

[33] NERA, op cit, 25-26.

Deloitte Touche Tohmatsu
A.B.N. 74 490 121 060
Riverside Centre
123 Eagle Street
Brisbane QLD 4001
Australia

DX 115
Telephone (07) 3308 7000
Facsimile (07) 3308 7001
www.deloitte.com.au

Deloitte Touche Tohmatsu

4 April 2003

The Directors
Murraylink Transmission Partnership
Level 11
77 Eagle Street
Brisbane QLD 4000

Dear Sirs

REGULATORY TEST – MURRAYLINK DISCOUNT RATE

SCOPE AND BASIS OF REVIEW

Deloitte Touche Tohmatsu ("Deloitte") has been engaged by Murraylink Transmission Partnership ("MTP") to provide accounting and financial advice and support services to assist with the preparation of a regulatory application for the Murraylink transmission project ("Murraylink"). MTP's application was provided to the Australian Competition and Consumer Commission ("ACCC") on 18 October 2002.

As part of this application Deloitte provided a letter to MTP titled "Regulatory Test – Murraylink Discount Rate", dated 16 October 2002, which developed an estimate of the base discount rate to be applied by MTP in performing the ACCC regulatory test as part of the process to obtain regulatory approval for Murraylink (the "Regulatory Test Discount Rate"). An estimate was also required of the low and high case scenarios around this base discount rate. The following table summarises the discount rates calculated (the discount rates are a real, pre-tax weighted average cost of capital ("WACC"):

Discount Rate	
Low	7.76%
Base	9.25%
High	10.40%

Subsequently, MTP's application has been subject to a public submissions process and a number of submissions have been made that refer to the Regulatory Test Discount Rates estimated.

As a result, MTP has requested Deloitte to perform the following agreed upon procedure:

1. Provide a response on the matters raised in submissions relating to the Regulatory Test Discount Rate. In particular, National Economic Research Associates ("NERA") has provided the only substantive comments in relation to the Regulatory Test Discount Rate in its report commissioned by TransGrid and Deloitte should refer specifically to section 3.1.4 of this report.

This letter reports our findings in relation to this agreed-upon procedure.

Deloitte
Touche
Tohmatsu

Declarations and restrictions

The scope of our work is limited to the matters set out above and governed by the terms set out in our Consultancy Agreement with TransÉnergie Australia Pty Limited dated 2 July 2002.

Our procedures and enquiries did not include verification work nor constitute an audit in accordance with Australian Auditing Standards ("AUS"), nor do they constitute a review in accordance with AUS 902 applicable to review engagements. Consequently, no assurance is expressed.

This report is for the sole use of MTP in accordance with the terms of reference established by you and as such cannot be relied upon or used for any other purpose without our express written permission. We accept no responsibility to any other person in relation to the contents of this report and no other person should rely upon any statement made in this report for any purpose.

Statements and opinions contained in this letter are given in good faith but, in the preparation of this letter, Deloitte has relied upon the information provided by MTP which Deloitte believes, on reasonable grounds, to be reliable, complete and not misleading. We have not corroborated the information received. Deloitte does not imply, nor should it be construed that it has carried out any form of audit or verification on the information and records supplied to us.

We note that we have not been requested to update our analysis for changes in the parameters underlying the Regulatory Test Discount Rate as a result of changes in markets (for example, movements in the market's expectation of future inflation or the current level of risk-free interest rates or debt margins). It is expected that these parameters will be updated at the time of the ACCC making its final decision.

RESPONSE TO NERA COMMENTS

TransGrid commissioned NERA to provide a report on MTP's application. NERA produced a report titled "Comments on Murraylink's Application for Conversion to Regulated Status: A Report for TransGrid", dated January 2003 (the "NERA Report"). Section 3.1.4 of the NERA Report specifically discusses a number of issues regarding the Regulatory Test Discount Rate.

The NERA Report is the only submission to the ACCC regarding MTP's application that discusses the discount rate in detail[1]. The key issues raised in the NERA Report were:

- 9.25% base discount rate is significantly below previous applications of the regulatory test that used a central estimate of 11%
- The parameters used in deriving the discount rate estimates are more applicable for a regulated business rather than a commercial business
- Lack of rationale for the 'low' discount rate
- Whether the Intelligent Energy Systems ("IES") parameters are nominal or real
- Whether the 'high' discount rate is pre or post tax
- Calculation of the equity beta for the 'base' discount rate

[1] The only other major comment was made by ElectraNet SA in paragraph 5.48 of its submission titled "Submission to ACCC Re Murraylink Transmission Partnership's Application for Conversion to a Prescribed Service and Maximum Allowable Revenue", March 2003. The issues raised by ElectraNet SA are covered in the discussion of the NERA Report issues.

Deloitte Touche Tohmatsu

- Inconsistency in the return on equity between the 'base' and 'high' discount rates
- Conversion from nominal to real using the Fisher Equation

Each of these key issues is discussed below.

Comparison of 9.25% to 11% discount rate

NERA indicates that the 9.25% discount rate used in MTP's application is lower than previous discount rates used of 11%:

> "*The 9.25% discount rate used by [MTP] is significantly below the central estimate of 11% used in other recent applications of the regulatory test.*"[2]

Further they go on to state:

> *"The IRPC used a real pre-tax commercial discount rate of 11% in its assessment of SNOVIC 400 and SNI.*
> *…*
> *The commercial discount rate has proved to be a relatively uncontroversial parameter in the regulatory test assessment. However, it should be noted that the IRPC was only required to* rank *alternative projects under the regulatory test, with the absolute values not being relevant. As such, to the extent that changes in the commercial discount rate do not change the rankings of alternative projects, the choice of discount rate would not be expected to be overly controversial. In contrast, [MTP's] choice of the discount [rate] will have a direct impact on the RAV derived for Murraylink."*[3]

In discussing this issue we wish to note the following key points:

- The "central estimate of 11%" appears to have limited supporting variables for its calculation.
- The 9.25% discount rate used by MTP is within the range of 8% to 11%, which is the range of base discount rates used in recent applications of the regulatory test.

These points are further developed below.

In determining an appropriate discount rate for MTP, Deloitte researched previous discount rates used in applications of the regulatory test. It soon became apparent that whilst the 11% discount rate used by IRPC appeared to be the benchmark rate, there was little or no supporting documentation or analysis on to the derivation of that discount rate[4]. As such, it became clear that this discount rate was only being used for the purposes of ranking alternative projects, and as NERA notes, as a result it would be a non-controversial parameter in the analysis.

[2] Page 17 of the NERA Report.
[3] Pages 17 and 18 of the NERA Report.
[4] NERA do not make any reference in their report to any applications/submissions/literature that indicates the underlying parameters to the estimate of 11%. This may indicate that NERA had the same difficulty as Deloitte in sourcing information on the basis of the 11%.

For MTP the discount rate will have greater significance, as it will be used to derive their regulated asset value. Hence greater analysis was put into the parameters underlying the discount rate to be used. In performing this more detailed analysis, it became apparent that the supposed parameters underlying 11% (we refer to further discussion below on the IES parameters) are not appropriate for the current market situation.

The "rationale for deviating from the 11% commercial discount rate used in previous applications of the regulatory test" was that this base rate of 11% had little supporting evidence and that just because this rate was used in the past does not necessarily mean that this is the right rate to use for MTP's application.

In addition the discount rate determined for MTP was in the range used by VENCorp and IRPC of 8% to 11%. NERA has not provided reasons as to why they do not discuss the VENCorp discount rate, however the 9.25% used by MTP is not significantly different to the mid point of the range 8% to 11%, which is 9.5%, indicating that the base discount rate used is within an appropriate range.

Regulated parameters versus commercial parameters

The NERA Report indicates that:

> *"DTT's analysis uses parameters which are appropriate for a* regulated *business rather than a* commercial *business, and contains a number of unsupported assumptions.*
> ...
> *DTT has again used the WACC/CAPM variables applicable to a* regulated *monopoly business, such as the debt equity ratio and debt premium (based on a regulated return), to derive a* commercial *discount rate."*[5]

In discussing this issue we wish to note the following key points:

- Regulators set regulated WACC's as a surrogate for commercial returns, and hence regulated WACC's are a relevant starting point for determining commercial discount rates
- To the extent that regulated and commercial discount rates will differ, this has been reflected in the adjustment made to the equity beta, with no adjustment to the debt margin and gearing ratio

These points are further developed below.

In the ACCC's report titled "Regulatory Test for New Interconnectors and Network Augumentations" dated 15 December 1999 (the "ACCC Guidelines") indicates that:

> *"The net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector."*[6]

The discussion in the ACCC Guidelines further states:

[5] Pages 17 and 19 of the NERA Report.
[6] Page 21 of the ACCC Guidelines.

Deloitte
Touche
Tohmatsu

"In order to ensure that regulated network investments are undertaken in a competitively neutral way in comparison to generation and non-regulated investments, the [ACCC] has accepted the argument that a commercial discount rate should be used."[7]

One of the principles underlying the determination of WACC's by regulators is to provide infrastructure holders with a competitive market return. For example, the ACCC has stated:

"It is important that the rate of return be set at an appropriate level which reflects a commercial return for the regulated businesses."[8]

The Office of the Regulatory-General, Victoria (the "ORG") has also indicated:

The specific objectives of the regulatory framework and the role of the [ORG] within it, is to act as a surrogate for the rewards and disciplines normally provided by a competitive market."[9]

Hence one would expect that many of the underlying parameters between a regulated and a commercial return would be similar, otherwise one should question whether regulators are getting their estimates of WACC correct.

There will, however, be differences due to risk profiles as regulated businesses have revenue streams that are more certain, whilst purely commercial businesses have greater risk.

The different risk profiles between commercial and regulated projects will see different equity betas, debt premiums and gearing ratios applied when calculating an appropriate WACC for the different projects. However, there are also some parameters that will not change between the two, for example the market risk premium and the real risk free rate.

For those parameters that could potentially be different between commercial and regulated projects (the equity beta, debt premium and gearing ratio), these are discussed below.

The equity beta has been adjusted and is discussed further below.

In relation to the debt premium, the question arises as to whether a commercial discount rate should include a higher debt premium than assumed in the Officer Paper[10]. In relation to the debt margin, the regulated WACC assumed in the Officer Paper is based on a BBB+ rated company, which provides a debt margin of 150 basis points. Analysing current credit ratings of generation companies in Australia indicates that their credit ratings are in the range of BBB to AA-[11].

---

[7] Page 5 of the ACCC Guidelines.
[8] Page 71 of the ACCC's "Statement of Principles for the Regulation of Transmission Revenue", dated 27 May 1999.
[9] Page 3 of the ORG's "Electricity Distribution Price Review: Cost of Capital Financing - Consultation paper number 4" dated May 1999.
[10] The Officer Paper is contained in Appendix G of MTP's application.
[11] Standard & Poors Australian and New Zealand Utilities Report, October 2002.

Deloitte Touche Tohmatsu

Company	Credit Rating
Delta Electricity	AA-
Edison Mission Energy	BBB
Snowy Hydro	BBB+

Regarding the gearing ratio the regulated gearing ratio of 60% has been used as it was seen to be slightly more conservative than the 65% used as part of the IES Parameters (refer to comments below). As the 65% was used in support of the 11% benchmark Regulatory Test Discount Rate, the lower rate of 60% (which causes the discount rate to be higher as it includes a greater proportion of the higher equity cost) was seen to provide a more appropriate discount rate.

Rationale for the 'low' discount rate

NERA indicates that:

> *"DTT does not provide any rationale for why this regulated return is a good proxy for a low commercial discount rate."*[12]

In discussing this issue we wish to note the following key point:

- As regulators set regulated WACC's as a surrogate for commercial returns, the regulated WACC's is considered an appropriate starting point for the low point of sensitivity analysis

As discussed above, regulators can set the regulated WACC at a level whereby it acts as a surrogate for the return received in a competitive market. Also, as noted above, there will be differences between the returns of a regulated business and a fully commercial business even though many of the underlining parameters will be the same. To that extent the regulated WACC as proposed in the Officer Paper has been used as the low end of the discount rate range on the basis that the regulated WACC is an appropriate surrogate for the commercial discount rate.

IES parameters

The IES report titled "Application of the ACCC Regulatory Test to SNI: Report to TransGrid" dated 27 November 2000 (the "IES Report") makes the following comments in relation to the 11% discount rate:

> *The ACCC test specifies that discount rates applicable to private enterprise investment be used in the NPV calculation. The discount rates used were 9%, 11% and 13% (pre-tax real). A 11% discount rate is consistent with the discount rate for a 65% geared project in which debt and equity rates are about 9% and 18% respectively. Such values are typical of many utility-based projects. The 9% and 13% discount rates represent a likely range about this rate."*[13]

[12] Page 18 of the NERA Report.
[13] Page 14 of the IES Report.

Deloitte
Touche
Tohmatsu

NERA indicate that:

> *"It is not readily apparent that the figures reported by IES are nominal rather than real: DTT's assumption that they are real decreases the discount rate by around 2.2%."*[14]

In discussing this issue we wish to note the following key points:

- The IES 11% discount rate is a real discount rate
- It is not clear from the IES Report whether the 9% and 18% debt and equity rates respectively are real or nominal
- It has been assumed that the rates are nominal, as to assume that they are real would imply unrealistic rates when compared to current market rates

These points are further developed below.

It is readily apparent that the 11% discount rate used by IES was a real discount rate, however it is unclear as to whether the 9% and 18% debt and equity rates respectively are real or nominal. Assuming that the 9% and 18% are quoted on the same basis (that is, they are either both real or both nominal rates), we examined the debt rate of 9% and determined that if this was a real debt rate and if inflation was added, it would imply a nominal cost of debt of around 11.2%. This provides an unrealistic cost of debt when compared to current market rates of debt of approximately 6.9%.

The IES Parameters were used to derive the high discount rate for MTP as these were the only previously reported parameters underlying a Regulatory Test Discount Rate, however, as noted above, they were considered too high to form parameters of the base discount rate when compared to current market rates. This gives these parameters support for sensitivity purposes (as the high-end scenario), but not as the base discount rate.

Pre or post-tax high discount rate

The NERA Report states:

> *"DTT's calculation of the high discount rate does not include any compensation for tax, resulting in the 10.4% derived being a post-tax rather than pre-tax discount rate."*[15]

In discussing this issue we wish to note the following key point:

- The assumptions are clearly noted in our letter dated 16 October 2002 as being pre-tax

It is unclear why NERA have interpreted the high discount rate provided as being post-tax. As the table on page 3 of our letter dated 16 October 2002 indicates, the inputs to the high discount rate are on a nominal pre-tax basis, which are then adjusted by inflation to derive the real pre-tax parameters.

---

[14] Page 18 of the NERA Report.
[15] Page 18 of the NERA Report.

Deloitte Touche Tohmatsu

One possible source for NERA's comment is that they have interpreted the IES parameters of 9% and 18% as being on a post-tax basis. The extract from the IES Report above does not indicate whether the debt and equity rates are pre or post tax (although if the figures are consistent with the comments made regarding the 11% base figure, they are on a pre-tax basis). However, if we assume that the debt rate of 9% is post-tax, this would imply that the pre-tax rate is 10.8%[16], once again a value that is high when benchmarked against current market debt rates indicating that the more accurate interpretation is that the 9% discount rate is a pre-tax rate to begin with.

Base discount rate equity beta

The NERA Report indicates that the equity beta is incorrectly calculated as the equity betas had not been unlevered and then relevered to the assumed gearing ratio for the base discount rate. Correcting for this issue results in the following adjustments:

	Previous Analysis		Relevered Equity Beta		
Company	**Equity Beta**	**Included**	**Equity Beta**	**Excluding Outliers**	**Including Outliers**
Energy Developments	0.74	Yes	1.05	Yes	Yes
Energy World	2.49	Yes	2.13	Yes	Yes
Pacific Energy	1.67	Yes	0.29	No	Yes
Pacific Hydro	2.16	Yes	4.49	No	Yes
Origin Energy	1.16	Yes	1.98	Yes	Yes
Horizon Energy	0.36	No[17]	0.24	No	Yes
Simple average		**1.644**		**1.715**	**1.694**

Using the higher of the two new equity betas of 1.715[18], this increases the base discount rate from 9.25% to 9.46%.

These adjustments to the base discount rate's equity beta will have no impact on the low or high discount rates.

Consistency between base and high discount rates

On page 19 of the NERA Report it is noted:

> *"There is inconsistency in the return on equity presented in the base case. The high discount rate uses a return on capital of 18% which DTT comment is a "high-end scenario" - however the base discount rate is based on an 18.28% return on equity, which is* greater *than the high-end scenario."*[19]

[16] Assuming a tax rate of 30% and value of imputation credits of 50%.
[17] Horizon Energy was previously excluded as an outlier.
[18] The equity beta excluding outliers has been used to be consistent with the methodology used in our letter of 16 October 2002 of excluding outliers in the analysis.
[19] Page 19 of the NERA Report.

Deloitte Touche Tohmatsu

The low, base and high discount rate were chosen on a particular scenario for each individual WACC as opposed to looking at a range of outcomes for each particular parameter of the WACC. This does lead to this minor inconsistency. To adjust the high-end discount rate return on equity to be above or consistent with the base case, would then make that return on equity inconsistent with the other parameters used for the high WACC scenario. In addition the high-end scenario WACC is used for sensitivity purposes only and greater emphasis should be placed on the base discount rate.

Nominal to real conversion

We acknowledge NERA's points in relation to the application of the Fisher equation and agree that the Fisher transformation is the accepted methodology for converting a discount rate from nominal to real (or vice-versa). As noted in our previous letter the conversion was calculated to ensure consistency between the calculation of the market discount rate and the calculations contained in the Officer Paper. Adjusting the calculation to the Fisher equation results in the discount rate decreasing from 9.25% to 9.05%, or alternatively taking into account the adjusted calculation of the equity beta would decrease the base discount rate from 9.46% to 9.25%.

Likewise the low discount rate would decrease from 7.76% to 7.59% and the high discount rate from 10.40% to 10.18%.

SUMMARY

In summary the low, base and high discount rates should be adjusted to the following:

	Low	Base	High
Deloitte Letter dated 16 October 2002	7.76%	9.25%	10.40%
Adjustment to equity betas	7.76%	9.46%	10.40%
Adjustment for Fisher Equation	7.59%	9.25%	10.18%
Update Discount Rates	**7.59%**	**9.25%**	**10.18%**

Should you have any queries or require any additional information please do not hesitate to contact Tim Emonson or myself of this office.

Yours sincerely

Deloitte Touche Tohmatsu

Peter Thornely
Partner

Further Comments on Murraylink Reliability Benefits and Other Modelling Issues

Prepared for

Murraylink Transmission Company

By

TransÉnergie US Ltd.

April 4, 2003

TransÉnergie US Ltd.
110 Turnpike Road, Suite 300
Westborough, Massachusetts 01581
United States of America
Phone +1 508-870-9900

Contents

1 Introduction

A number of submissions have been made to the Australian Competition and Consumer Commission in relation to Murraylink Transmission Company's (MTC's) application of October 18, 2002 and TEUS' report contained in Appendix D of the application.

Some of these submissions have observed that the method TEUS used to calculate Murraylink's reliability benefits is different from the method used by the Inter-regional Planning Committee for SNI, that TEUS has not explicitly modeled reliability entry plant, and that the inclusion of reliability plant would provide a lower level of unserved energy. This paper explains why TEUS believes the method it has used is more appropriate, and, simply for the purpose of comparison, how its results would be different if TEUS had used a method that explicitly incorporated reliability entry plant.

This paper also deals with a range of other issues that were raised by stakeholders in relation to market modeling and the calculation of Murraylink's market benefits.

2 Reliability Benefits

2.1 The Unserved Energy Standard and Reliability Entry Plant

The NECA Reliability Panel recommends a maximum level of unserved energy (USE) less than or equal to 0.002% of annual energy consumed. Active enforcement of this reliability standard presumes that:

- the National Electricity Code (Code) will continue to enable NEMMCO to procure reserve contracts for any additional capacity resources[1] (referred to generally as "reliability entry plant"); and
- NEMMCO will determine to enter into reserve contracts for the provision of reserve to ensure that the reliability of supply in a region meets the reliability standard.

For a previous studies conducted by NEMMCO in which reliability benefits of a new interconnector have been calculated, an estimate has been made of the change in the amount of reliability entry plant that NEMMCO would procure if the interconnector is in place. The reliability benefit was the economic benefit of avoiding investment in that plant.

[1] The additional resources could be supply-side (i.e. new generation), or demand-side (i.e. interruptible load).

2.2 The TEUS Method

In the estimate of Murraylink's Gross Market Benefits prepared by TEUS and submitted to the Commission with MTC's application in October 2002, TEUS estimated Murraylink's reliability benefits by measuring the expected change in unserved energy attributable to Murraylink's operation, and valued at the current VoLL of $10,000/MWH as described in Appendix D of Murraylink Transmission Company's Application for Conversion to regulated status..

2.3 Most Appropriate Method

TEUS strongly believes its method remains the best approach to estimating the true value of an interconnector's reliability benefits.

The points described in section 2.1 of this paper are the essential features of NEMMCO's reserve trader function and are designed to deal with circumstances in which market forces fail to bring forth the necessary generation investment during the period in which the NEM matures[2]. To date, no such reserve contracts have been written. Currently, the Code specifies that NEMMCO's reserve trader function will come to an end on 1 July 2003. NECA has applied to the Commission seeking authorization of Code changes that could extend NEMMCO's reserve trader functions until July 2005, and the Commission's decision is pending.

TEUS's method is fully consistent with the National Electricity Code and the expectation that, even if NEMMCO's reserve trader functions are extended until July 2005, there is less chance that it will be extended beyond that time given the extent to which the market had matured already and the potential for the very existence of the reserve trader Code provisions to distort on-going market outcomes. In any case, given the lead times necessary to bring on new generation plant and the uncertainties of load forecasting, there are real practical impediments to the effectiveness and precision with which NEMMCO, as the reserve trader, can achieve its objective.

The TEUS methodology presumes only that VoLL represents the appropriate value of USE, and that market forces will continue to determine future market entry.

In fact, by relying on a value of VoLL of $10,000/MWh even in real terms, TEUS may actually underestimate the true benefit, when one considers that VENCorp is proposing to use a value of $29,600/MWh for transmission planning purposes[3].

[2] NECA 19 September 2002, Letter to ACCC seeking authorisation of Code changes that could extend NEMMCO's reserve trader functions until July 2005.
[3] VENCorp 25 March 2003, *Response to submissions: The value of unserved energy to be used by VENCorp for electricity transmission planning*.

3 Results Incorporating Reliability Entry Plant

To the extent that NEMMCO's reserve trader functions operate actively in the future, additional reliability entry plant would be added in amounts and locations as necessary to ensure that annual expected USE in each region will remain less than or equal to 0.002% of the energy consumed in the region.

Using the TEUS method, in some instances of the MARS reliability simulations in the year 2009 and beyond, expected levels of USE did slightly exceed the 0.002%. To determine the reliability plant that NEMMCO, as the reserve trader, would have to procure to achieve the unserved energy standard, TEUS used the MARS reliability simulation model and added reliability entry plant to the Base Case merchant entry schedule in regions and years where USE exceeded 0.002%. The simulations were repeated, adding progressively more reliability entry plant, until all regions satisfied the criterion in all years. In response to comments made to the ACCC by Saha Energy International Ltd. (SEIL) in its January 2003 report that extending the modeling horizon would provide a more robust view of long term market benefits, the simulations were carried out through 2018 using the Extended Base Case prepared by TEUS and described in the TEUS report included in MTC's March 17, 2003 submission.[4]

The Extended Base Case merchant entry schedule and the resulting reliability entry plant schedule are shown below in Table 1.

Table 1

Merchant Entry Plant and Reliability Entry Plant (MW)

	Base Case Merchant Entry			Reliability Entry Plant			Total Deferred Plant
	Without Murraylink	With Murraylink	Deferred Merchant Entry	Without Murraylink	With Murraylink	Deferred Reliability Entry	
2003	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0
2008	0	0	0	50	0	50	50
2009	50	0	50	250	250	0	50
2010	300	150	150	350	350	0	150
2011	700	500	200	350	350	0	200
2012	900	750	150	450	500	-50	100
2013	1300	1050	250	450	500	-50	200
2014	2050	1800	250	400	550	-150	100
2015	3000	2550	450	400	650	-250	200
2016	3750	3450	300	500	650	-150	150
2017	4450	4000	450	600	750	-150	300
2018	5250	5050	200	650	650	0	200

[4] See the discussion of Sensitivity Tests on page 4 of the report titled "Further Comments on Murraylink Market Benefits".

All reliability entry plant additions are assumed to be Open Cycle Gas Turbines, as described in the IRPC's SNI Stage 1 Report. The difference in required levels of reliability entry plant is valued in the same manner as deferred merchant entry has been valued in the original TEUS analysis. As can be seen from Table 1, the With Murraylink case in 2012 requires 50 MW more reliability entry plant than the Without Murraylink case. As Murraylink defers 150 MW of combustion turbine market entry, this results in a total deferral of combustion turbine capacity of 100 MW (= +150 MW Merchant Entry Deferral – 50 MW Reliability Entry Plant Deferral).

In 2018, the same amount of reliability plant must be added to both the With and Without cases to achieve the 0.002% criterion, resulting in deferred reliability entry plant. The total deferral is just the 200 MW of deferred merchant entry plant. In the years 2013-2017, higher amounts of merchant entry in the Without Murraylink case reduce the need for reliability plant, resulting in total deferred plant levels of approximately 200 MW.

Murraylink's estimated impact on any remaining unserved energy (which will be smaller than in the Base Case because of the additional reliability entry plant in both the With and Without Murraylink simulations) is calculated in exactly the same manner as for the original Base Case gross market benefits estimate, and as described in the October 2001 submission.

This analysis indicates a Gross Market Benefit of $172m when reliability entry plant is included to achieve the NECA 0.002% unserved energy standard.

Note that the energy benefits and Riverland Deferral benefits are unchanged by the addition of reliability plant. However, Deferred Capacity Benefits (including both Merchant Entry and Reliability Entry) and Reliability Benefits are decreased. The reliability benefits of adding Murraylink or, for that matter, any other generator or transmission augmentation, to an already highly reliable system, will be less than the benefits of making the same addition to a system where reliability is determined only by market forces and VoLL of $10,000/MWh.

4 Other Market Benefits Modelling Issues

4.1 Riverland Deferral Benefits

TEUS notes that some stakeholders queried the manner in which TEUS determined Murraylink's Riverland deferral benefits. While TEUS understands the uncertainty associated with any load forecast, TEUS determined Murraylink's Riverland deferral benefits using the best available information from valid public sources such as the South Australian ESIPC. As such it stands by its original determination set out in its report contained in MTC's Application.

4.2 Snowy Hydro Dispatch

Two submissions made to the ACCC comment that particular assumptions about Snowy Hydro dispatch may be necessary to support high Murraylink transfer levels under certain conditions.

TEUS notes that for its market benefits modeling, a) the Snowy Hydro generation has been assumed to operate as peaking generation, b) the SnoVic interface limit used is the present 1900 MW, not the higher limit of 2010 MW that might require a directed Snowy dispatch, and c) if higher transfers were necessary to preserve system reliability and such transfers could be achieved by NEMMCO issuing specific dispatch instructions to certain generators, then it can reasonably be assumed that NEMMCO would take the required actions. This is no different than assuming that available generators would be directed to operate by NEMMCO, and would actually generate when unserved energy would otherwise result.

4.3 Double-counting Deferred Merchant Entry Benefits and Reliability Benefits

One submission suggests that the TEUS methodology has the potential to double-count deferred merchant entry benefits and reliability benefits.

As explained in the original TEUS report (Appendix D of MTC's application), we have endeavored to keep these issues separate. The estimation of deferred market entry plant is calculated using the PROSYM model, based on energy market economics of the NEM with and without Murraylink. The MARS model is then used to estimate the expected of Murraylink on unserved energy in both the With and Without Murraylink cases. This becomes the separate estimate of Murraylink's reliability benefit.

4.4 Lightning Detection Equipment on the Heywood Interconnector

ElectraNet has argued that the installation of lightning detection equipment on the Heywood interconnector may significantly reduce the number of hours per year in which Heywood transfer capability into South Australia must be derated to 250 MW. TEUS has tested the sensitivity of this assumption and found that, with no lightning-related forced outages on the Heywood interconnector, Murraylink's base case market benefits would decline by $3m to $211m. Conversely, the Heywood constrained limit into South Australia for the six months ending February 28, 2003, was at or near 250 MW approximately 12% of the time. The constraints are attributable to a range of factors, including electrical storms. As an upper bound on the impact of Heywood outages, a 12% Heywood forced outage rate produces an estimate of $251m for Murraylink's base case gross market benefits. This range of estimates ($211-251m) indicates that TEUS' original estimate of $214m is reasonable and well within the range of uncertainty associated with electrical storm activity, despite the addition of lightning detection equipment.

ElectraNet notes that during hours when the Heywood interconnector is constrained to transfer levels below 500 MW, the constraints are not necessarily binding. TEUS agrees, but notes also that no Heywood derates or outages were assumed for any of the PROSYM modeling used to estimate energy benefits and deferred merchant entry. The PROSYM modeling has been conservative in this regard.

4.5 Intraregional Constraints

ElectraNet suggests that the use of thermal limits to model certain intraregional constraints is inappropriate. TEUS notes that the more traditional approach of modeling only interregional constraints effectively assumes away the existence of intraregional constraints. The application of intraregional thermal constraints clearly adds additional conservatism to the MARS reliability analysis.

4.6 Modelling of Murraylink Limits in PROSYM

One stakeholder observed that TEUS modeled the Murraylink transfer limits from Victoria to South Australia in PROSYM by assuming a constrained transfer capability during February afternoon weekdays and July-August morning and afternoon peak periods. These time periods were based on historical interface flows during 1999-2001, and it is suggested that this historical period may not reflect future conditions. TEUS now believes that it was unnecessary to include the time-period based Murraylink constraints in the original PROSYM modeling, as the PROSYM dispatch engine will automatically enforce an appropriate constraint. In other words, PROSYM will not export power from Victoria to South Australia unless there is surplus power available in Victoria. Under these conditions, Murraylink would be able to use its full rated capacity.

During periods when the SnoVic interface is fully loaded and no surplus capacity exists in Victoria, PROSYM will not export power over Murraylink. TEUS believes the time-period based limits were overly conservative. Removing the limits increases the base case gross market benefit by slightly over $5m to $219.5m.

TransÉnergieUS
Member of the Hydro-Québec group

Memorandum

To	Date	Doc ID	Page
Murraylink Transmission Company	March 19, 2003		1 of 4

Cc	Issued by
	J. J. Miller, B.D. Railing, J. B. Lowell

Replaces	Subject
	Treatment of Murraylink Losses in the Calculation of Market Benefits and A Comparison to Estimated Losses for AC Alternative 3

Background

At the request of Murraylink Transmission Company (MTC), this memorandum reviews the treatment of Murraylink Losses in the estimation of Gross Market Benefits prepared by TransEnergie US, and presents an estimate of transmission power losses associated with an AC transmission interconnection as an alternative to the Murraylink HVDC project.

Murraylink losses can impact the estimated energy benefits and reliability benefits that Murraylink provides to the NEM. As discussed in more detail below, TransÉnergie US (TEUS) has appropriately accounted for these impacts in the PROSYM and MARS simulation models used to estimate market benefits.

Some submissions made to the ACCC incorrectly characterize Murraylink losses as significantly higher than alternative AC designs. This memorandum estimates the losses for BRW's Alternative Project 3, an AC line between Red Cliffs and Monash, as described in Appendix F of MTC's Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12, dated 18 October 2002, and shows that during important high load periods, losses over Murraylink will be less than losses over Alternative Project 3.

AC Alternative 3 was identified by BRW as the lowest cost in the MTC application that offers a level of service near equal to the Murraylink project. AC Alternative 3 also interconnects between the same ac network substation locations as the Murraylink project, therefore, AC Alternative 3 provides a sound basis for a comparison of losses to Murraylink. A curve of estimated transmission losses versus AC delivered power over AC Alternative 3 (AC Alt. 3) has been established by TEUS and is presented in the attached Figure 1. For comparison, the Murraylink estimated transmission loss curve (Murraylink Est.) and the Murraylink actual transmission loss curve (Murraylink Actual) are provided on Figure 1.

Treatment of Losses in Estimation of Market Benefits

The estimation of Murraylink's market benefits involves modeling of the Austrailian NEM in two stages:

1. estimation of market entry, generator dispatch and interregional flows with and without Murraylink using the PROSYM model
2. estimation of Murraylink's reliability benefits (reduction in unserved energy) using the MARS model

Losses over Murraylink and other interconnectors have been accounted for in both models, as described in the TEUS report, "Estimation of Murraylink Market Benefits", included as part of Murraylink Transmission Company's submission to the ACCC in October 2002. The PROSYM model also incorporates the impact of intraregional loss factors on generator dispatch.

Consequently, all estimates of Murraylink's market benefits prepared by TEUS reflect the change in system operation and system cost caused by differences in system losses with and without Murraylink.

More specifically, losses are incorporated into the PROSYM model in two ways. First, PROSYM allows quadratic loss equations (where losses are a quadratic function of flow) to be specified for each of the links between the five regions in the NEM. The model inputs describing these equations were developed from the interregional dynamic loss equations published in the IRPC's SNI Stage 1 Report. Separate loss equations for flows in each direction are specified, as necessary. Murraylink loss parameters were developed from an estimated loss function prepared by TEUS and were based on preliminary technical specifications provided by the equipment manufacturer.

Secondly, short run marginal costs for each generator have been adjusted by the generator's marginal loss factor to develop the bid price for the generator used by PROSYM to calculate hourly generator dispatch.

The MARS model does not provide a direct means of accounting for interregional losses, because it does not perform an economic system dispatch. Interconnector losses effectively consume capacity that otherwise would be available to reduce unserved energy. Accounting for the capacity consumed by losses is therefore important when measuring changes in unserved energy. TEUS has addressed this by making hourly adjustments to the load traces used by MARS to account for the capacity required to meet losses. Hourly flows between regions are provided by the PROSYM simulations. The hourly flows are used in conjunction with the interregional loss equations were used to calculate hourly losses in each direction over each link. The estimated hourly losses are then added to the hourly load at the sending end of the transmission link. This preserves the locational impact of losses on unserved energy in each of the nine regions simulated in the MARS model.

Murraylink's losses include losses related to the level of power being transmitted, and losses related to the status ("blocked" or "deblocked") of the converter terminals. When the terminals are "blocked", Murraylink incurs only 0.39 MW of losses at each terminal and is unable to transmit power. When the terminals are "deblocked", Murraylink incurs no-load losses of approximately 3.76 MW, plus any flow-related losses. The calculation of losses for the MARS simulation assumes that in hours when PROSYM indicates flows of less than 5 MW, Murraylink would be "blocked" and would incur only 0.39 MW of losses at the SA and Vic terminals. In all other hours, the 3.76 MW of no-load losses are incurred.

The estimated Murraylink loss equation used in the market benefits modeling is:

$$\textbf{Losses} = \mathbf{3.76 + .00017 \times Flow + .00008 \times Flow^2}$$

Loss measurements made after Murraylink began operations in 2002 have shown that actual losses are significantly lower than the estimated losses used in the market benefits modeling (see Figure 1 below). Consequently, the TEUS estimate of Murraylink market benefits is conservative. The benefit calculations have incorporated the impacts of intraregional and interregional losses in a consistent manner throughout. The losses ascribed to Murraylink are conservatively high, which will act to understate the total gross market benefits.

Estimated Losses for AC Alternative 3

Description of Alternative 3

As outlined in Appendix F of the MTC application, AC Alternative 3 consists of the following primary components:

- 220 kV AC interconnection between the Redcliffs 220 kV substation in Victoria and the Monash 132 kV substation in South Australia.
- 25 km section of interconnection assumed to be underground cable with the remainder over head transmission.
- 220-132 kV Phase Shifting Transformer (PST) at Monash end of interconnection.
- -110 to +120 MVAr Static Var Compensator (SVC) at Monash
- 30 MVAr switched shunt reactors at Red Cliffs.

Calculations

AC Alternative 3: Estimated losses where calculated using the PSS/E Power Flow package with the following assumptions:

- 1 per unit voltage held at Red Cliffs 220 kV and Monash 132 kV
- Power transfer direction from Red Cliffs to Monash
- Impedance for 153 km overhead transmission segment based on data taken from Australian PSS/E database for 220 kV line between Red Cliffs and Horsham, R = 10.67 ohms/phase, Normal rating = 267 MVA
- 25 km of 220 kV underground cable - 1000 mm2 Aluminum conductor, R = 1.12 ohms/phase including estimate of screen conductor influence
- 132-220 kV PST at Monash, R = 0.0027 per unit on 100 MVA base
- 400 KW stand-by losses on Monash SVC assumed based on recent SVC installation data
- No load losses are due to charging current, cable dielectric loss representation, PST magnetization and SVC stand-by losses.

Murraylink (Estimated): Prior to the construction and commissioning of Murraylink, an estimated transmission loss curve for the Murraylink project was established by TEUS based on calculated data provided by the equipment manufacturer. The estimated transmission loss curve is for all losses between the 220 kV ac bus at Red Cliffs to the 132 kV ac bus at Monash, including the auxiliary power losses. An estimated loss curve was provided to NEMMCO in July, 2001. This loss data (Murraylink Est.) is presented in the memo for comparison to the estimated losses over AC Alternative 3 and the actual losses measured on Murraylink.

Murraylink (Actual): During commissioning of the Murraylink project, test block TRANS-8 was performed during Sept 14-16, 2002 to verify transfer capability and losses. All of the auxiliary power was provided by the Murraylink power transformer tertiary windings during this test block. The cooling systems for the IGBT valves, phase reactors, building areas and power transformers were operated at maximum during TRANS-8 to simulate cooling load at 40ºC dry-bulb air temperature. The actual loss curve was created by using the actual MW values from the 220 kV and 132 kV utility revenue meters.

Results

Figure 1 illustrates the results of the calculations summarized above. For each option, the corresponding curve shows transmission losses (MW) versus AC delivered end power (MW). The flow direction is from Victoria to South Australia, therefore, the delivered power is at the Monash 132 kV bus. Sending end power at the Red Cliffs 220 kV bus can be calculated by adding the transmission loss to the delivered power at any point on a given curve. As shown, the actual measured losses over the Murraylink project are significantly less then the initial estimated losses, especially for higher power transfer levels. This is primarily due to lower actual converter station losses as compared to the estimated values provided by ABB.

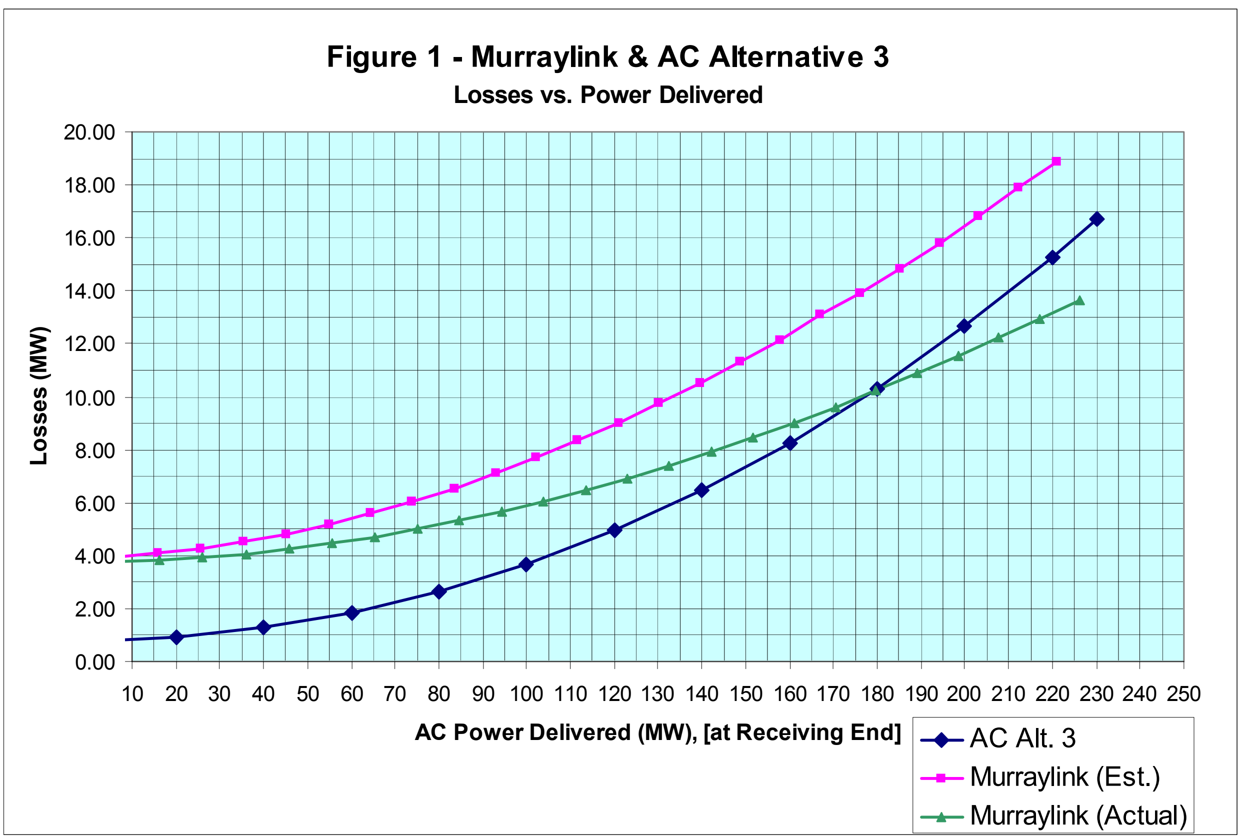
In comparing the estimated AC Alternative 3 losses to the actual Murraylink losses, the AC alternative losses are less at low power levels, however, for high power transfers, the losses are less for Murraylink. The crossover level for equivalent losses between the two options is approximately 176 MW of delivered power. At 220 MW delivered, AC Alternative 3 estimated losses are 16% higher than the actual calculated losses over Murraylink. During periods of high power transfer over the interconnector, where network reliability will often be most crucial, incremental transfers over Murraylink will incur less loss as compared to AC Alternative 3.

During periods of zero or low transfers over Murraylink where the cost of losses may out weigh the benefit of transferring power, Murraylink can simply block power transfer and go into stand-by mode. Losses associated with stand-by mode are estimated to be 778 kW. The stand-by condition for Murraylink is defined as:

1. Red Cliffs Converter Station is connected to the 220 kV ac bus at Red Cliffs Substation but the IGBT valves are "blocked" from switching. Auxiliary power is supplied to the converter station via the tertiary winding on the converter power transformer.

2. Berri Converter Station is connected to the 132 kV ac bus at Monash Substation but the IGBT valves are "blocked" from switching. Auxiliary power is supplied to the converter station via the tertiary winding on the converter power transformer.

3. The dc transmission cables are connected at both converter stations, and are energized to about 276 kV dc.



Burns and Roe Worley

Burns and Roe Worley Pty Ltd

Level 15, 300 Flinders Street
Melbourne, VIC 3000
PO Box 293 Collins Street West
Melbourne, VIC 8007 Australia
Telephone +61 3 9291 7700
Facsimile +61 3 9291 7770
www.burnsandroeworley.com.au

BRW

power & water expertise

2 April 2003

REF: 024/45003

Murraylink Transmission Company
GPO Box 7077
Riverside Centre
BRISBANE QLD 4001

Attention: Stéphane Mailhot
Chief Executive Officer

RE: MURRAYLINK ACCC ISSUES PAPER

Dear Stéphane

Burns and Roe Worley (BRW) is pleased to provide the following responses to issues raised in submissions to the ACCC regarding Murraylink Transmission Company's application for conversion to a prescribed service.

1 The Type of Alternative Projects to be considered

Response

The methodology used by BRW in assisting the Murraylink Transmission Company (MTC) to propose the opening regulatory asset value (RAV) was "to select and assess alternative projects that offer the same technical service (and hence, the same market benefits) as Murraylink". Alternatives having system characteristics different to those of Murraylink were not pursued.

As indicated in the Executive Summary of BRW's report *TransÉnergie – Murraylink Selection and assessment of alternatives* (16 October 2002), the technical service identified included the following:

- Provides an additional 220 MW injection capability into the South Australian region during moderate and light load periods. It can also provide at least an additional 110 MW injection capability into the South Australian region during peak load periods. This can occur even when Victorian generation is constrained and excess generation must be sourced from the New South Wales region, subject to a prudent level of additional voltage support.
- Maintains a power transfer capability from the Victorian to South Australian regions even during times when the Heywood to South East substation ("SESS") interconnector is constrained. For example during times of lightning activity in the south-east region, Heywood transfer is reduced from 500 MW to 250 MW.
- Provides an additional 220 MW injection capability into Victoria from South Australia subject to constraints related to Riverland load and generation capacity in the South Australian region. During times of heavy Riverland load, Murraylink will be constrained to lower levels to prevent overloading the 132 kV circuits between Robertstown and Monash substations.

- Provides reactive support and assists with regulating the voltage profile of the AC networks at both the sending and receiving ends of the link. The reactive support is provided in a controlled manner, with minimal delay time and without incremental block changes as would otherwise be offered by shunt reactors and capacitor banks. Previously synchronous condensers provided this form of "smooth" reactive support, though the modern equivalent is an SVC. This reactive control is classified as an ancillary service and ranges from –110 MVAr to +140 MVAr during rectifier operation and –125 MVAr to +120 MVAr during inverter operation.
- Provides an additional transmission in-feed into the Monash substation 132 kV bus that relieves a potential future non-compliance with the SA Transmission Code[1], which defines the Riverland as a category 3 connection point. Such substations require all customer loads to be supplied under a single element contingency without load shedding.

Submissions to the ACCC have proposed a number of alternative projects and these have been assessed against the above technical services as follows:

Alternative	**220MW injection in South Australian Region (from Victoria)**	**Maintains power transfer capability during times when Heywood is constrained**	**220MW injection into Victorian Region (from Sth Australia)**	**"Smooth" reactive support**	**Additional transmission Infeed into Monash substation**
SNI	No [1]	No	No	No	No [2]
Heywood A + Robertstown Monash	No [3]	No	No	No	Yes
Horsham A + Robertstown Monash	Yes	No	Yes [4]	No	Yes
NEWVIC 2500	No	Yes	Yes [5]	No	No
SA/VIC 150MW Upgrade [6]	See note 6	See note 6	See note 6	See note 6	See note 6
SNOVIC800	No	Yes	Yes [5]	No	No
Synergen	See note 7	See note 7	See note 7	See note 7	See note 7

Notes

1. With reference to *NEMMCO 5.6.6(b) Assessment of SNI, September 2001*, page 10, figure 4, the SNI project can deliver only 180MW to South Australia and 70MW to Victoria, for a total of a 250MW increase to the combined SA and Victoria regions.
2. SNI project, as defined in the document *IRPC – SNI Stage 2 Report Version 7.0, 26 October 2001*, does not provide for a transmission infeed to the Monash substation.
3. Heywood A, as defined in *Interconnection Options Working Group – Technical Issues and Costs of Interconnection Options for South Australia* increases transfer by only 130MW.

4. No detailed analysis has been undertaken by BRW to confirm that a 220MW transfer from Sth Australia to Victoria is achievable, and publicly available documentation confirming that such a transfer is possible has not been identified.

5. Increase in transfer is between Snowy/NSW and Victoria, not South Australia and Victoria.

6. BRW is unaware of a SA/VIC 150MW transfer increase project, unless this is referring to Heywood A option which is discussed in note 2 above.

7. With reference to Section 4.7.1 of BRW's report dated 16 October 2002, "Capital costs for open cycle gas turbine plant varies between $400 – $700 per kW depending on unit size, market conditions and the prevailing exchange rate. Taking the mid-range costing, the total capital cost for 220 MW of open cycle gas turbine is around $121 m. For combined cycle plant, the mid-range capital costs on a per MW basis has been assessed at $1000 per kW, or $220 m for a 220 MW facility. These costs exclude the operation and maintenance costs associated with generation alternatives and any augmentation that may be required to supply gas to the region." (BRW notes the recent generation constraints incurred in South Australia due to reduced availability of the Moomba gas pipeline.) "Even at low levels of generation, when these costs are included in any net present cost analysis, the total cost associated with these alternatives is in excess of the transmission alternatives."

2 Reason for inclusion of SVC/voltage control

Response

BRW has included SVC's in the alternative projects to provide a level of performance equivalent to that of Murraylink.

However, beyond this requirement there is a system need for fast acting automatic voltage control within the local system network around Red Cliffs and Monash.

Specifically for Alternatives 1 and 3, fast voltage control is required to control system voltage in the event that the link must be tripped. In most situations, Murraylink need not be tripped but it may be required to rapidly reduce power transfer ie: to provide fast runback. Without fast voltage control, the voltage at Monash substation may collapse under some situations. Red Cliffs substation may experience very high voltages under similar situations.

For strict equivalence with Murraylink, two SVCs should be costed for Alternatives 1 and 3 - one at Red Cliffs (or at Buronga) and one at Monash. Given that SVCs already exist at Kerang and Horsham which will provide limited voltage control for the Red Cliffs area. Consequently, BRW has only costed one SVC (at Monash) even though this does not strictly provide an equivalent service to that of Murraylink.

It is important to note, that in similar situations, SVCs have been installed for similar reasons or simply used to reduce losses during power transfers. For example, the SVC's at South East (2 SVC from +80 MVAr to –50 MVAr) are used to provide fast automatic voltage regulation for the existing link between Victoria and South Australia. There are also SVC's at Bremar and Armidale associated with the QNI interconnection between Queensland and NSW. They are very common in the USA and Europe wherever long interconnections between power systems occur. In some cases, it could be argued that SVCs are not required - but their absence would place greater restrictions on the operation of the system, and lead to a lower quality of power supply sometimes leading to voltage collapse conditions. It would also reduce the market benefits of any scheme.

3 *Component costings are excessive*

Response

BRW notes that in TransGrid's analysis of the alternatives, a number of detailed observations are made, particularly in its Appendix (*Analysis of Proposed Alternative Projects*). Each issue has been addressed below.

Alternative 1

(a) TransGrid states "Two 275/132kV transformers are provided at Monash with a spare. In reality one transformer is required at Monash with a spare if necessary";

BRW notes that 2 x 160MVA transformers are proposed to achieve the 220MW transfer into Monash. This is based on good engineering principles in that it allows for interchangability with existing ElectraNet 275/132kV transformers (which are typically sized at 160MVA). One transformer could have been installed but would have required a higher MVA rating at a greater cost (and would not be suitable for other ElectraNet substations). TransGrid appears not to have considered the size of the transformer when making this statement.

(b) TransGrid states the "provision of a spare phase shifting transformer appears unnecessary".

BRW notes that in the absence of this device, failure of the unit would cause the 220MW transfer to be unavailable for an extended period until the unit could be repaired or a new unit manufactured. BRW has applied good engineering principles in ensuring a suitable spare is available for this critical plant item.

(c) TransGrid states "the line and cable cost is given as $88M compared to an overhead line of the order of $30M";

BRW agrees with TransGrid. An AC cable is an expensive item, but tactical undergrounding is likely to be necessary to abide by the likely outcome of statutory environment approval processes.

(d) TransGrid states "An SVC is included at Monash at a cost of $19M, however, in early TransGrid/ETSA studies on network development similar to this option, an SVC was not required";

Refer to item 2 above.

(e) TransGrid states "the 132 kV connection cost at Monash is stated as $10M but TransGrid considers this is more likely to be of the order of $2M. A detailed engineering review is required to estimate the cost of the works";

BRW believes TransGrid has misinterpreted the basis for including this cost. $A10.4M is the estimated cost of a new 132kV injection point into the Riverland area of South Australia. This injection point became known as the Monash Substation which was substantially paid for, and built by MTC as part of the Murraylink interconnection project. In the absence of Murraylink, any alternative would be required to develop the Monash substation for connection to the South Australian system.

(f) TransGrid states "BRW quote the total cost of transformers (without spare) and connection at Monash to be in the order of $20M whereas, in the context of the SNI project, TransGrid considers that a cost of less than $10M would be incurred for connecting SNI at Monash with a single transformer";

With reference to the Base Cost Estimates contained in Section 3, Appendix 5 of BRW's report dated 16 October 2002, the total cost of switchyard works, not including SVC, PST and Monash connection costs noting this the cost of the substation alone, prior to any 275kV interconnection) are approximately $A30M which includes;

- 2 x 160MVA 275/132kV transformers
- 2 x 220kV CBs and 1 x 30MVAr reactor at Buronga
- 4 x 275kV and 1 x 132kV CBs at Monash
- Augmentation of existing plant due to impact of new interconnection (ie: switchgear replacements due to increased fault levels)

$A10M to connect SNI at Monash using a single transformer does not appear inconsistent with our estimate for substation works; however, a full scope of works proposed by TransGrid would be necessary before BRW could comment on such costs.

(g) TransGrid states "mention is made of "Augmentation of existing plant due to impact of new interconnection with increased fault levels". No details seem to be provided and these details are required to provide further comment";

Without detailed access to plant characteristics, available only to SPI Powernet and TransGrid, BRW is unable to determine what, if any network augmentations may be required due to the interconnection. However, it is not unreasonable to expect such work to be necessary. For example, in *NEMMCO 5.6.6(b) Assessment of SNI – Appendix C – VENCorp Report September 2001*, pages 3 and 4 approximately ten 22kV CBs at Red Cliffs may require to be replaced, and two 220kV CBs at Mount Beauty as a result of the SNI project. Similar works may be required as a result of Alternative 1.

(h) TransGrid states "no communications development costs appear to be included".

BRW would expect these costs to be included in the above augmentation costs discussed in (g) above.

Alternative 2

(a) TransGrid states "Spare converter transformers are included for each end of the link. It is not known whether such spares were purchased for Murraylink. In TransGrid's view only one dual voltage spare converter transformer is needed for Murraylink on the basis that it has three single-phase converter transformers at either end".

One spare transformer with multiple tappings (to allow for connection at either end of the HVDC line) is included in the estimate. BRW understands that MTC purchased two spare single phase units, with a unit located at either end of the link.

(b) TransGrid states "The cost breakdown of Appendix 5 of MTC's Application indicates that the Red Cliffs - Monash line and cable section would cost in the order of $53 million. The HVDC overhead line should cost of the order of $150k per km, with a total of the order of $23M based on 180 km route length that includes a 25 km underground section. Hence the 25 km of underground cable is costed at the order of $30M. TEA has often stated that undergrounding costs less than an overhead line. The cabling appears to cost of the order of $1.2M per km. Even if the line cost $200k per km or $31M this leaves 25 km of cable costing $22M or $0.9M per km. As a result, it is difficult to understand the costs of this option."

BRW's costs were based on in-house databases and quotations from suppliers. The assumed cost for an overhead DC transmission line is approximately $A140k/km (which is lower than the assumed value of approximately $A170k/km for an overhead AC line as less conductor is required and smaller towers). The DC cable costs are assumed to by 67% of the cost (both for supply and installation) of an equivalent AC cable.

Alternative 3

(a) With respect to power transfer TransGrid states "It appears that BRW has not taken into account the fact that operation of this new line with power flow of the order of 200 MW would significantly stress the NSW 220 kV system."

In the detailed costings provision is made for augmentations back within the SPI and TransGrid systems. Whilst acknowledging the differing reactive requirements, BRW would expect that if 220MW can be currently transferred across Murraylink from Red Cliffs, this should be achievable utilising AC transmission and phase shifting transformers.

It is important to note that with the existing system intact a 220MW transfer can easily be supported. The immediate post-contingent situation however is the major determinant in power transfer capability. In this regard Murraylink capability is facilitated by the use of automatic runback to alleviate post-contingent overloads and in some cases voltage violations. For an AC link an analogous automatic response is also required (in lieu of major augmentations). For SNI it was proposed to simply 'trip' the link between Buronga and Robertstown for certain contingencies in the south west NSW and Vic state grid network. BRW assumed its AC alternatives would also be tripped during such a contingency.

The advantage of the "runback" feature inherent in Murraylink is that it leaves the network intact with the VSC converter stations providing reactive support at each connection point, where as in the case of SNI tripping the Buronga to Robertstown lines, the system is "de-meshed", raising the impedance between points, increasing generator angle and potentially impacting on angle stability. With appropriate runback control an HVDC link can better utilise existing upstream network assets without the need for major augmentations and/or tripping of major components of an AC interconnector (as is proposed for SNI and any other AC link providing equivalent service level).

Alternative 4

(a) TransGrid states "BRW give the cost of the 275 kV from Heywood to South East Line as $38M. The IOWG estimated $150k per km over 80km, that is at $12M. TransGrid considers the BRW cost very high."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A38M reflects the cost of the 130km 275kV line section between Robertstown and Monash, and the 80km 275kV line section between Heywood and South East.

(b) TransGrid states "BRW estimate $6.4M for the series capacitors, while the IOWG estimated $24M for these works although it is possible that BRW has included part of the series capacitor cost in the switchgear cost."

BRW acknowledges the discrepancy. The estimate of $A6.4M reflects only the plant costs. Installation costs, civil works and associated switchgear costs have not been included.

(c) TransGrid states "BRW estimate the cost of switchgear at $22M. The IOWG estimated the switchgear costs would be in the order of $12M."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A22M reflects the cost of switchgear for works at Robertstown, Monash, South East and Heywood.

(d) TransGrid states "BRW estimate the cost of the transformer as $10.6M and the IOWG estimate for this is $9M."

The IOWG estimate is based on costs in 1997 dollars. Escalating the IOWG value would give a cost for the transformer to within 10% of BRW's estimate.

(e) In the context of the inclusion of the phase shifting transformer, TransGrid states "With a new third line in place the interconnector could then be rated at a higher secure level during storms. This may be above 500 MW depending on the rating of the new plant. As a result, the phase shift transformer is probably redundant – there is no need to provide power flow control given adequate rating on the other plant. The Heywood transformer is rated at 600 MVA and the line rating should not present any difficulty."

BRW notes that with a third line operating between Heywood and South East, there will be the existing double circuit line, and a third single circuit line. During periods of storm activity, the existing double circuit line is derated to 250MW (from a pre storm activity rating of 500MW). This derating would likely remain in place when the third line is placed in service. As there would be three lines in parallel (with essentially the same electrical characteristics), a reduction in the double circuit transfer to 250MW would also reduce the transfer in the single circuit line of 50% (or 110MW is the pre storm activity transfer was 220MW). To maintain the pre storm activity transfer of 220MW on the third line a phase shift transformer would be required.

Note that BRW understands the Heywood transformers have a firm rating of only 370 MVA, and an emergency rating of 525MVA.

(f) TransGrid states "The Monash works include a new 275/132 kV transformer and an SVC. The cost of transformers is given as $10.6M. It appears that this would cover two transformers. The system would be secure for loss of a transformer hence the reason for a spare is not clear."

BRW believes TransGrid has misinterpreted the nature of this estimate. The $A10.6M reflects the cost of a 500/275kV transformer at Heywood, and a 275/132kV transformer at Monash.

(g) TransGrid states "An SVC is included at Monash at a cost of $19M. In the ElectraNet and ESIPC work on the Riverland reinforcement there was no need for an SVC in addition to the 275 kV line. Presumably BRW seeks to provide the same level of voltage control as provided by Murraylink."

Refer to item 2 earlier detailing the reasoning for inclusion of SVC's.

(h) TransGrid states "the 132 kV connection cost at Monash is stated as $10M but TransGrid considers this is more likely to be of the order of $2M. A detailed engineering review is required to estimate the cost of the works";

As noted in item (e) for comments relating to Alternative 1, BRW believes TransGrid has misinterpreted the basis for including this cost. $A10.4M is the cost of a new 132kV injection point into the Riverland area of South Australia. This injection point became known as the Monash Substation which was substantially paid for, and built by MTC as part of the Murraylink interconnection project. In the absence of Murraylink, any alternative would be required to develop the Monash substation for connection to the South Australian system.

General comment on Costs

On page 21 of TransGrid's submission, costings are provided for various interconnection projects. The main source for these costs is the IOWG report *Technical Issues and Costs Of Interconnection Options for South Australia*. BRW notes that all estimates are quoted in 1997 dollars.

BRW also has a number of concerns with respect to the accuracy of these estimates, particularly the $A110M figure being quoted for the SNI project. This project has changed considerably in scope since the report above was published (ie: the above estimate does not include costs for the Jindera phase shifting transformer). It is also noted that the original estimate had no provision for many of the components critical to achieving the nominal 220MW transfer proposed for the SNI interconnection (such as line uprating works in south west NSW). BRW believes a thorough review of the SNI scope of works, including itemised cost estimates for all peripheral works be undertaken before credence be given to the $A110M estimate for this project.

4 Reason for profit and overhead

Response

BRW's original cost estimate assumed an EPC (Engineer, Procure and Construct) contractor would manage the switchyard and transmission line works as a total project. The BRW cost estimate has been derived from a "bottom-up" process. This involves obtaining quantities and cost estimates for plant and equipment from suppliers, estimating material quantities and labour hours, including detailed engineering and project management on an at cost basis, then applying profit and overhead margins. This estimating process simulates the development of an all-inclusive EPC cost to deliver a total project.

Yours sincerely
Burns and Roe Worley

R McD Touzel
General Manager Consulting

Murraylink Transmission Company

SNI

Option Cost Estimate

Document No. 45003-04

16 April 2003

Revision	Project Number	Description	Prepared by	Reviewed by	Approved by
0	024/45003	Revised Draft	Andrew Robertson	Bruce Petersen	Rod Touzel

Burns and Roe Worley Pty Ltd
ABN 98 000 886 313

Melbourne: Level 15 300 Flinders St Melbourne VIC 3000 (PO Box 293 Collins St West Melbourne VIC 8007) Tel 61 3 9291 7700 Fax 61 3 9291 7770
Perth: Level 5 QV1 Building St Georges Terrace Perth WA 6000 Tel 61 9 278 8345 Fax 61 9 278 8383
Sydney: Level 7 116 Miller Street North Sydney NSW 2060 (PO Box 1812 North Sydney NSW 2060) Tel 61 2 8923 6800 Fax 61 2 8923 6801
Brisbane: Level 6 80 Albert Street Brisbane QLD 4000 (PO Box 81 Albert Street Brisbane QLD 4002) Tel 61 7 3221 2347 Fax 61 7 3221 7791

EXECUTIVE SUMMARY

Murraylink Transmission Company engaged Burns and Roe Worley Pty Ltd (BRW) to prepare an independent capital and lifecycle cost estimate of the SNI project as defined in NEMMCO's December 2001 *Determination under Clause 5.6.6 of the Code – SNI Option* (the NEMMCO determination). This estimate was prepared using the same costing approach that BRW used for its report *TransÉnergie-Murraylink: Selection and Assessment of Alternatives* dated 16 October 2002. Murraylink Transmission Company also requested that BRW provide an estimate of the SNI Option with and without undergrounding of the line through the Bookmark Biosphere consistent with the underground of this section in BRW's Alternative 1 from its report of 16 October 2002.

BRW relied on the scope of the SNI Option defined in the NEMMCO determination and other publicly available submissions made to NEMMCO as identified in this report. Publicly available information does not provide BRW with the same level of certainty about the precise scope of the SNI Option that BRW was able to achieve for the Murraylink alternative projects. Where BRW has made assumptions about the scope of SNI, the assumptions have been stated in this report.

The following tables summarise the BRW cost estimate for the SNI Option at May 2003 price levels.

Summary of SNI Option Costs (May 2003 price levels)

	As Defined in the NEMMCO Determination **$000**	**With Tactical Undergrounding** **$000**
Total Capital Cost	192,147	263,244
O&M Costs	1.56 /yr	1.56 /yr
Total NPV Capital Cost	181,245	246,319
O&M Net Present Value over 40 years	14,493	14,493
Total Net Present Value	**195,739**	**260,812**

This costing is simply for the actual development and construction of the SNI Option. BRW makes no interpretation as to how a revision of the SNI Option's actual costs will affect the NEMMCO determination. BRW's costing does not represent a regulatory asset valuation such as that the Australian Competition and Consumer Commission might undertake using a depreciated optimised replacement value or deprival value methodology under the National Electricity Code.

BRW has not had access to a detailed breakdown of the TransGrid estimate of $109.5M (assumed 2001 price levels) for the SNI Option confirmed to NEMMCO in November 2001. A comparison was made with a breakdown provided to the ACCC by ESIPC on 23 March 2003 based on material placed before the National Electricity Tribunal. Escalating the estimated cost from TransGrid to May 2003 price levels ($116.16M) results in the TransGrid cost being approximately $76M lower than the BRW estimate ($192M which includes contingency). Based on the breakdown provided by ESIPC, the TransGrid estimate is significantly lower in most categories, particularly when development costs are allowed for. BRW's estimate allows for contingency based on a probabilistic risk assessment. Details are not available on the allowance or basis for contingency in the TransGrid estimate. Similarly, BRW's estimate allows for interest during construction and TransGrid's allowance for this cost is unknown.

TABLE OF CONTENTS

1 CLIENT BRIEF

Murraylink Transmission Company has requested Burns and Roe Worley Pty Ltd (BRW) to prepare a paper setting out an independent capital and lifecycle cost estimate of the SNI project as defined in NEMMCO's December 2001 *Determination under Clause 5.6.6 of the Code – SNI Option*.

MTC requested that this estimate be prepared using the same rigorous costing approach that BRW used in its report *TransÈnergie Australia - Murraylink: Selection and Assessment of Alternatives* dated 16 October 2002. This approach involves collating detailed and current industry data held by BRW and provided by key suppliers to determine a base cost of the project, which BRW has analysed using a fully integrated project risk assessment process to determine the cost that a transmission owner would be most likely to pay for the whole project.

Murraylink Transmission Company also requested that BRW provide an estimate of the SNI Option with and without undergrounding of the line through the Bookmark Biosphere consistent with the underground of this section in BRW's Alternative 1 from its report of 16 October 2002.

In responding to this brief, BRW has relied on the scope of the SNI Option as defined in the NEMMCO determination and clarifications provided in other publicly available submissions to NEMMCO as identified in this report. Publicly available information does not provide BRW with the same level of certainty about the precise scope of the SNI Option that BRW was able to achieve for the Murraylink alternative projects. In some instances where the scope of work has not been well defined, BRW has made assumptions and these have been stated. BRW has not carried out studies to confirm the requirements or scope for the SNI Option and BRW does not warrant performance or completeness of the scope of work used as the basis for this estimate.

This costing is simply for the actual development and construction of the SNI Option. BRW makes no interpretation as to how a revision of the SNI Option's actual costs will affect the NEMMCO determination. BRW's costing does not represent a regulatory asset valuation such as that the Australian Competition and Consumer Commission might undertake under using a depreciated optimised replacement value or deprival value methodology under the National Electricity Code.

2 SNI SCOPE OF WORKS

2.1 SNI Detailed Scope of Project Works

The scope of work of SNI to be covered in this estimate is that defined in NEMMCO's *Determination under Clause 5.6.6 of the Code – SNI option*. A more detailed scope for these works is set out in *5.6.6(b) Assessment of SNI Appendix A – SNI Project Works*, IOWG September 2001.

The works, as detailed in the documents above are as follows:

Line Works

Construction of a 275kV single circuit line from Buronga to Robertstown.

Upgrading the Darlington Pt – Balranald – Buronga line from 220kV to 275kV operation.

Uprating the Lower Tumut – Wagga 330kV line (continuous rating exceeding 890 MVA and 5 minute rating exceeding 1250 MVA).

Uprating a number of NSW 132kV lines. The lines include:

- Yass to Wagga, Yass to Wagga via Murrumburrah and Yass to Wagga via Tumut 132kV lines;
- Wagga to Yanco 132kV lines
- Wagga to Finley 132kV line

Darlington Point Substation

Installation of one 330/275kV transformer.

Development of a single 275kV bus and switching works.

One 50MVAr switched shunt reactor connected to the 275kV line.

One 132kV 40 MVAr capacitor bank.

Buronga Substation

Installation of one 275/220kV transformer.

Bus development and switching modifications for 275kV and 220kV.

One 50 MVAr shunt reactor switched to the Darlington Pt line.

One 30 MVAr shunt reactor switched to the Robertstown line.

Installation of 220kV capacitor banks with a total rating of 100 MVAr.

Robertstown Substation

One 30 MVAr shunt reactor switched to the Buronga line.

One 100 MVAr capacitor bank. This will be switched to the 275kV bus.

Jindera Substation

One 132kV, 60 MVAr capacitor bank.

One 330kV phase shifting transformer at Jindera on the Jindera – Wodonga 330kV line. The phase shifter is to be continuously variable to 30 degrees with automatic controls. It will also be fitted with voltage boost capability.

Yass Substation

Additional Yass 330/132kV transformer (which possibly brings forward by one year a project already under consideration).

Dederang Substation

Advancement of fourth 330/220kV transformer at Dederang, identical to the existing transformers.

One 220kV, 200 MVAr capacitor bank at Dederang or relocated to other suitable locations.

Capacitor Bank Installations

Capacitor bank works in New South Wales to support the SNI project.

All banks to be fitted with automatic controls to allow post-contingency switching

- Canberra – one 132kV, 120 MVAr capacitor bank
- Wagga – two 132kV, 120 MVAr capacitor banks
- Finley – one 66kV, 6 MVAr capacitor bank
- Deniliquin – two 66kV, 8 MVAr capacitor banks replacing the existing 5 MVAr banks

Control Systems

Control schemes to be implemented to trip SNI for overloads and reactive deficiencies (as a result of SNI flow) on:

- Selected 220kV circuits in Victoria
- Selected 66kV circuits in Victoria
- Selected 132kV circuit in NSW

Other Victorian Works

Dederang – Glenrowan – Shepparton 220kV line switching upgrade including one new circuit breaker

A small amount of 22kV switchgear at Red Cliffs and up to two 220kV circuit breakers at Mount Beauty will be upgraded if necessary

3 ADVANCEMENT COSTS

With reference to the detailed scope as detailed in Section 2.1, there are a number of items which are not solely required as part of the SNI project. Rather, they represent works that might be required due to load growth, but would be brought forward (advanced) as a result of the SNI project. As the determination for SNI was made in 2001, BRW has attempted to identify which projects within the SNI Option scope of works are required just to be brought forward, and BRW has designated them as “advancement costs” within the SNI Option. These costs are an NPV cost in 2003 dollars.

These works are;

Line Works

Of those works identified under this heading in Section 2.1, only the uprating of the Lower Tumut – Wagga 330kV line is considered as an advancement cost.

BRW has reviewed the *2001* and *2002 NSW Annual Planning Reports* and no indication is given as to whether the 132kV line upgrades are required external to the SNI project and thus, the full costs of these works remain in the estimate.

Darlington Point Substation

Based on a review of the *2002 NSW Annual Planning Report* (page 73), which indicates the requirement for a 40MVAr capacitor bank at Darlington Point, BRW has assessed the cost of the 132kV 40MVAr capacitor bank nominated as part of the SNI Option project to be required by 2003 with an associated cost of advancing the project by 2 years.

Yass Substation

As noted in Section 2.1, installation of an additional Yass 330/132kV transformer is an existing project under consideration. However, in neither the 2001 nor the *2002 Annual Planning Report* is the explicit installation of an additional Yass transformer stated. Rather, the *2001 NSW Annual Planning Report* (page 42) and *2002 Annual Planning Report* (page 33) indicates the refurbishment of the 330kV Yass substation is required by late 2004.

As the installation of an additional Yass transformer is stated in the scope of works for the SNI Option, BRW has considered this project to be required by 2004, with an associated cost of advancing the project by 3 years.

Dederang Substation

As noted in Section 2.1, the fourth 330/220kV transformer at Dederang should be considered an advancement cost. As the *2002 VENCorp Annual Planning Report* (page 73) states that the fourth transformer is likely to be required by 2005, BRW has included an associated cost of advancing the project by 4 years.

There has also been a major increase in capacitor bank installations at Dederang (and surrounding substations) associated with SNOVIC project. However, the 220kV 200 MVAr capacitor bank nominated as part of SNI would still have been required in the absence of SNOVIC and thus, the full cost of this work has been included.

Capacitor Bank Installations

Based on a review of the *2002 NSW Annual Planning Report* (page 73), which indicates the requirement for 120MVAr capacitor banks at Wagga and Canberra by 2003, BRW has included a cost of advancing these installations by 2 years.

As the original scope of works indicates two 120 MVAr capacitor banks at Wagga would be required, BRW has included the full cost of the second 120MVAr capacitor bank.

Note also that *2002 NSW Annual Planning Report* (page 72) indicates that capacitor banks have recently been installed at Finley and Deniliquin. BRW has also included a cost of advancing these installations by 2 years. However, given the relative size of these projects, the contribution of this advancement cost to the base cost is negligible.

Other Victorian Works

The line switching upgrades at Dederang, Glenrowan and Shepparton were identified in the VENCorp *2001 Annual Planning Review* as being required in 2 to 4 years. As these works would be necessary for the SNI Option, their costs are included as advancement costs.

The costs for the nominated switchgear replacements are not considered as advancement costs and the full costs have been included.

4 DETAILED CAPITAL COSTS

All figures at May 2003 price levels.

4.1 Basis of Cost Estimate

Cost Estimates were prepared on the same basis and using the same unit prices as the estimates for the alternative projects in BRW's report "*TransÉnergie Australia – Murraylink: Selection and Assessment of Alternatives*" dated 16 October 2002. All costs have been adjusted to May 2003 price levels.

A breakdown of the estimates for the transmission line, switchyard and advancement capital costs has been provided in Appendix 1. Scoping assumptions have had to be made due to the lack of detail in the publicly available information relating to the SNI Option scope. These have been stated in Appendix 1 against each cost category. The development costs have also been estimated on the same basis as those for the alternative projects and these include the costs of feasibility and environmental studies, consultants (e.g. technical, environmental, legal and market) and the planning, environmental and regulatory approvals processes.

The proponent of SNI does not propose currently to include undergrounding through the Bookmark Biosphere and the environment impact of the SNI Option is still being assessed and conditions are yet to be placed on its approval by State and Commonwealth planning bodies. The development costs of the alternative projects were determined on the basis that their proponent would accept the need for tactical undergrounding. As Saha Energy International Limited stated in its review of BRW's assessment of Murraylink's alternative projects, it is quite likely that the costs of obtaining planning and environmental approvals would be significantly higher without undergrounding[1]. Therefore, BRW's estimate of the costs of obtaining planning and environmental approvals for SNI is conservative.

The base cost estimate (May 2003 price levels) for the SNI Option as defined in the NEMMCO determination is provided in Table 4.1.

[1] Saha Energy International Limited, February 2003, *Review of Murraylink Transmission Company Pty Ltd's Application of the Regulatory Test*, p. 60.

	$000
Total Development Costs	10,608
Easements	8,380
Total Transmission Line Cost	*66,421*
Total Switchyard Cost	*65,465*
Contractor overhead and margin	*13,189*
Subtotal EPC PROJECT COST	145,074
Total Base Project Cost	**164,062**
Interest during construction	14,497
Advancement Costs	4,986
TOTAL PROJECT COST	**183,545**

Table 4.1 - Base cost estimate for SNI option as defined in NEMMCO determination

Interest during construction has been calculated on the basis of capital outlays as described in Table 4.2.

4.2 Time Schedule and NPV Cost

BRW understands that TransGrid is currently undertaking an environmental impact study (EIS) for the SNI Option. Allowing time for the completion of this work and finalising all other internal and regulatory approvals, BRW considers that a commissioning date of summer 2005/06 whilst optimistic could be achievable. Table 4.2 is a schedule used as a basis for the allocation of expenditure for evaluation purposes and the calculation of net present value (NPV) costs.

Note that expenditure for advancement costs detailed in Table 4.1 above are not included in the derivation of the NPV for the base project cost

Year To	Dec 2001	Dec 2002	Dec 2003	Dec 2004	Dec 2005
	40% Development works budget	30% Development works budget	30% Development works budget	50% EPC budget	50% EPC budget

Table 4.2 - Capital outlays for completion of SNI program

Based on the above program, BRW has determined the NPV of the SNI Option capital cost in Table 4.3. Interest during construction has been calculated using a real cost of debt of 4.7% as derived by Deloitte Touche Tohmatsu (Appendix C of MTC application) from Prof. Officer's assessment of MTC's weighted average cost of capital (Appendix G of the MTC application)

	$000
NPV of Total Base Project Cost	*154,855*
NPV of Interest during construction	*13,522*
NPV of Total Base Project Cost	**168,377**
Advancement Cost	4,986
NPV of TOTAL PROJECT COST	**173,363**

Table 4.3 - NPV of base cost estimate for SNI option as defined in NEMMCO determination

5 SNI WITH UNDERGROUNDING THROUGH BOOKMARK BIOSPHERE

The proposed SNI project traverses the Bookmark Biosphere area and follows the same route on that used for BRW's Alternative 1 project[2].

As stated in BRW's report dated 16 October 2002, Kellogg Brown & Root (KBR) has advised that tactical undergrounding of a transmission line through the Ramsar Wetland area of the biosphere would likely to be required to meet environmental management objectives under the statutory approvals processes. BRW's base cost estimate for Alternative 1 allowed for 30km of tactical undergrounding based on KBR's "most likely" estimate of the requirement for undergrounding in this route.

As indicated in section 4.1 of this report, BRW notes that while the proponent of SNI does not propose currently to include undergrounding through the Bookmark Biosphere, the environment impact of the SNI Option is still being assessed and conditions are yet to be placed on its approval by State and Commonwealth planning bodies.

Table 5.1 provides an estimate of the base cost (May 2003 price levels) of the SNI Option as defined in the NEMMCO Determination allowing for 30km of tactical undergrounding consistent with the costing methodology and assumptions used by BRW in the assessment of its Alternative 1 project.

	$000
Total Development Costs	10,608
Easements	8,380
Total Transmission Line Cost	*127,307*
Total Switchyard Cost	*65,465*
Contractor overhead and margin	*19,277*
Subtotal EPC PROJECT COST	212,049
Total Base Project Cost	**231,036**
Interest during construction	19,344
Advancement Costs	4,986
TOTAL PROJECT COST	**255,367**

Table 5.1 - Base cost of SNI Option as defined in NEMMCO determination plus tactical undergrounding through Bookmark Biosphere

Based on the expenditure program listed in Table 4.2, BRW has determined the NPV of the SNI Option capital cost in Table 5.2.

[2] As defined in BRW's report "*TransÈnergie-Murraylink: Selection and Assessment of Alternatives*" dated 16 October 2002.

	$000
NPV of Total Base Project Cost	*216,219*
NPV of Interest during construction	*17,896*
NPV of Total Base Project Cost	**234,115**
Advancement Cost	4,986
NPV of TOTAL PROJECT COST	**239,101**

Table 5.2 - NPV of base cost estimate for SNI option as defined in NEMMCO determination plus tactical undergrounding through Bookmark Biosphere

6 PROBABILISTIC RISK ASSESSMENT

Risk factors associated with projects such as the SNI Option lead to uncertainties in cost estimating. As outlined in Sections 3.5 and 3.6 of BRW's report *TransÈnergie Australia – Murraylink: Selection and Assessment of Alternatives* dated 16 October 2002, a structured risk analysis approach was used to allow for a wide range of risk factors and to determine an appropriate level of contingency.

After a detailed risk assessment, BRW developed a lump sum estimate for the SNI Option based on a P75 level, i.e. a level of which the project has a likelihood of exceeding the project estimate. The level of contingency to achieve the P75 level was calculated using a probabilistic method.

BRW has provided separate advice to MTC on the rationale for the choice of contingency levels for projects such as the SNI Option. This rationale relates to the extent to which most but not all risks can be specifically addressed in a project risk assessment.

The result of this risk assessment is summarised in Table 6.1.

	As Defined in the NEMMCO determination $000	**With Tactical Undergrounding $000**
Total Project Cost	183,545	255,367
Contingency	8,602	7,877
Total Capital Cost	**192,147**	**263,244**
NPV of Project Cost	173,364	239,101
NPV of contingency	7,882	7,217
Total NPV Capital Cost	**181,245**	**246,319**

Table 6.1 - Cost of SNI option based on risk assessment

NPV of contingency assumes 50% spent by December 2004, and the balance spent by December 2005.

7 LIFE CYCLE COSTS

Table 7.1 provides a summary of the life cycle capital and O&M cost estimates for the SNI Option. Costs have been expressed in May 2003 price levels and net present value costs determined based on a 9.25% discount rate consistent with the methodology of BRW's report *TransÉnergie Australia – Murraylink: Selection and Assessment of Alternatives* dated 16 October 2002.

The assumed O & M cost is $A1.56M per annum. This figure is derived by escalating the proposed $A1.33M O & M cost for the previous SANI project (as detailed on page 45 of the report *Interconnection Options Working Group – Technical Issues and Costs of Interconnection Options for South Australia*) by 4% per annum over 5 years.

The relative level of the O&M cost is lower than that for the Murraylink alternative projects as the SNI option is an increment to an existing system for TransGrid rather than a new stand-alone project and O&M structure.

	As Defined **$000**	**With Tactical Undergrounding** **$000**
Total Capital Cost	192,147	263,244
O&M Costs	1.56 /yr	1.56 /yr
Total NPV Capital Cost	181,245	246,319
O&M Net Present Value over 40 years	14,493	14,493
Total Net Present Value	**195,739**	**260,812**

Table 7.1 - Summary of life cycle costs for SNI option (May 2003 price levels)

It should be noted that the NPV values for the capital costs and life cycle costs have been calculated by assuming a distribution of the capital cost over a project life as indicated in Section 4.2. The analysis carried out in the ROAM Consulting report to NEMMCO and the Inter Regional Planning Committee (*Economic Evaluation of the Proposed SNI Interconnector*, October 2001) as input to the NEMMCO determination assumed the total capital cost to be expended in a single year. This assumption is considered to be unrealistic.

The analysis also appeared to make no allowance for escalations to the capital costs that would be expected to have occurred from the original estimate prepared by TransGrid in 1997. BRW expects the source for the SNI base cost used in the Roam Consulting study to be TransGrid[3].

[3] Refer to letter DW Hutt (TransGrid) to Dr Stephen van der Mye (NEMMCO) on 23 November 2001 confirming the SNI Project cost of $A110M. This estimate has not changed since the 1999 report *Interconnection Options Working Group – Technical Issues and Costs of Interconnection Options for South Australia* despite significant changes to the scope.

8 COMPARISON OF COSTS

BRW has not had access to a detailed breakdown of the TransGrid estimated cost for the SNI Option. In response to request from NEMMCO on 19 November 2001 seeking a breakdown of the estimated cost as part of the determination process, TransGrid provided the following broad breakdown of the estimated cost[4]:

	$M
Design/other	4.3
Environmental	4.5
Easements/property	7.9
Equipment Procurement and Construction	92.9
Total	**109.5**

Table 8.1 - TransGrid SNI Cost Breakdown

ESIPC's letter to the ACCC dated 23 March 2003 provides a more detailed breakdown of the estimated cost based on material placed before the National Electricity Tribunal[5]. This breakdown is given in Table 8.2 as a comparison to BRW's cost estimate breakdown. As the TransGrid costs and ESIPC's reporting of these are understood to relate to the time of the NEMMCO determination in December 2001, BRW has escalated these costs at 4% per annum to facilitate comparison with the BRW costs (May 2003 price levels).

SNI ELEMENT COST	**ESIPC** ($M Dec 01)	**ESIPC** ($M May 03)	**BRW** ($M May 03)
Buronga to Robertstown Transmission Line	59.09	62.68	62.06
Line Upratings in NSW	6.20	6.58	11.00
Darlington Point Substation Upgrade	8.94	9.48	13.67
Buronga Substation Upgrade	11.50	12.20	18.26
Communications and Control Systems	3.60	3.82	1.65
Jindera substation works	8.40	8.91	18.64
Robertstown works	5.00	5.30	7.92
Dederang and Red Cliffs area upgrades	5.53	5.87	9.31
Wagga Substation works	1.23	1.30	
Canberra Cap Bank			2.56
EPC Project Cost			**145.07**

[4] Letter DW Hutt (TransGrid) to Dr Stephen van der Mye (NEMMCO) on 23 November 2001

[5] ESIPC's letter refers to a witness statement by Dr Colin Parker of TransGrid.

SNI ELEMENT COST	ESIPC ($M Dec 01)	ESIPC ($M May 03)	BRW ($M May 03)
Advancement Costs			4.99
Easement Costs			8.38
Miscellaneous development costs			10.61
Interest during construction			14.50
Contingency			8.60
Total Project Base Cost	**109.49**	**116.16**	**192.15**

Table 8.2 - Cost Comparison of ESIPC and BRW estimates

There are obvious differences due to cost categories used by the respective parties and in this respect it is noted that:

- Easement costs have been treated as a line item by BRW as they would not form part of an EPC contact for the project works. It is likely that these costs would be included in the ESIPC/TransGrid Buronga to Robertstown transmission line costs.
- BRW has grouped costs for Shepparton Switching Works, Dederang Capacitor Bank and Red Cliffs Area Switchgear Replacements and classified them as "Dederang and Red Cliffs upgrades" to facilitate comparison with the ESIPC/TransGrid costs. As noted in section 2.1, Mt Beauty is likely to require switchgear replacements which have been included in BRW's estimate.
- Wagga substation costs have been treated as an advancement cost by BRW.
- BRW has determined advancement costs for line and substations works as detailed in Section 3 – as an NPV cost and not part of an EPC contract, this has been segregated. TransGrid's treatment of advancement costs is not known, and they could be included in respective substation and line categories.
- ESIPC/TransGrid has not segregated estimates for project development costs. As noted in Table 8.1, TransGrid has estimated $8.8M (December 2001) for "Design/Other" and Environmental costs. On an escalated basis, $9.3M (May 2003) is relatively comparable with BRW's estimate of $10.6M for miscellaneous development costs.
- ESIPC/TransGrid's costs do not indicate an allowance for interest during construction. As noted in Section 7, the Roam Consulting report to NEMMCO and the Inter Regional Planning Committee (Economic Evaluation of the Proposed SNI Interconnector, October 2001) allocated the capital costs to be expended in one year and this is considered to be unrealistic. IDC is a real and significant cost and should be allowed for.
- BRW's estimate makes provision for a contingency component based on a probabilistic risk assessment at the P(75) level. TransGrid's allowance for contingency is unknown.
- BRW has segregated project development costs including project management, design environmental and other approvals.

The following comments are made on areas of significant higher cost difference between the estimated comparative costs:

- Transmission line costs appear comparable. It is likely that the ESIPC/TransGrid costs include an allowance of $8.4 Million for easements ($ May 2003), in this event the ESIPC/TransGrid costs would be some 12.5% lower than the BRW costs.
- Line Upratings in NSW. Detailed scope definition and inspection of the relevant lines would be required to comment on the cost difference.
- Darlington Point Substation Upgrade. The ESIPC/TransGrid cost is some $4.2 Million lower than the BRW estimate. BRW considers the ESIPC/TransGrid estimate as low given the need to develop a 275kV switchyard with 330/275kV transformation and provision of reactive plant.
- Buronga Substation. The ESIPC/TransGrid costs is some $4.2 Million lower than the BRW estimate. BRW considers the ESIPC/TransGrid estimate as low given the need to develop a 275kV switchyard with 275/220kV transformation and provision of reactive plant.
- Jindera Substation Works. The ESIPC/TransGrid costs is approximately $6 Million lower than the BRW estimate. BRW considers the ESIPC/TransGrid costs to be low given the requirement for installation of a phase shifting transformer and is significantly higher costs compared to those of a conventional transformer.

As ESIPC/TransGrid has not segregated the $9.4M development cost in its estimate, it is assumed that this cost is distributed across the various cost categories. This is equivalent to 8% of the total project base cost. Segregation of the development component would effectively lower the cost of individual ESIPC/TransGrid work categories, thus increasing the cost difference to the BRW estimate for the various work categories.

MURRAYLINK Transmission Company

GPO Box 7077
Riverside Centre, Brisbane, 4001
Level 11, 77 Eagle Street, Brisbane, 4000
Phone: 61-7-3211 8617
Facsimile: 61-7-3211 8619

on behalf of **MURRAYLINK Transmission Partnership**

4 April 2003

Pass Through Rules

1. REGULATED PASS THROUGH

1.1 Rules form part of revenue cap

These Pass Through Rules form part of the revenue cap set by the Commission to apply to MTC for the regulatory control period commencing on [***date to be inserted when known***]. Any Pass Through Amount approved under these Pass Through Rules forms part of the revenue cap.

1.2 Pass Through Event

Each of the following is a Pass Through Event:

(a) a Change in Taxes Event;

(b) a Service Standards Event;

(c) a Non-contestable Capital Works Event;

(d) a Terrorism Event; and

(e) an Insurance Event.

1.3 Entitlement to pass through

If a Pass Through Event occurs, MTC is entitled or may be required to amend the revenue cap to pass through the financial effect of the Pass Through Event in accordance with the procedures set out in these Pass Through Rules.

1.4 Form of Pass Through Amount

A Pass Through Amount will reasonably reflect the factors in clause 3.4 and be expressed as an increase or decrease in the amount of the revenue cap (with its Relevant Coordinating Network Service Providers to determine the corresponding change in transmission charges in accordance with the Code).

2. ANNUAL INSURANCE INFORMATION

2.1 MTC to provide annual insurance information

MTC will provide to the Commission a copy of insurance premium invoices at least 50 business days before the start of each financial year.

3. PROCEDURE

3.1 Initiation of pass through

(a) If Commission believes MTC is or will be entitled or required to pass through the financial effect of a Pass Through Event, it may instruct MTC to give a Notice of Proposed Pass Through to the Commission in relation to a Pass Through Event specified by the Commission.

(b) If Commission instructs MTC give a Notice of Proposed Pass Through to the Commission in relation to a Pass Through Event specified by the Commission, MTC will do so in accordance with clause 3.2.

(c) If MTC believes it is or will be entitled or required to pass through the financial effect of a Pass Through Event, then it may give a Notice of Proposed Pass Through to the Commission in accordance with clause 3.2.

3.2 Notice of Proposed Pass Through

A Notice of Proposed Pass Through will include:

(a) details and documentary evidence of the relevant Pass Through Event;

(b) the date on which the relevant Pass Through Event took effect or will take effect;

(c) the estimated financial effects of the Pass Through Event on the provision of revenue capped transmission services; and

(d) the Pass Through Amount proposed by MTC in respect of the relevant Pass Through Event.

3.3 Determination by the Commission

(a) The Commission will, within the Assessment Period, determine whether the Pass Through Event specified in the Notice of Proposed Pass Through did occur (or will occur).

(b) If the Commission determines that the Pass Through Event did occur (or will occur), the Commission will determine:

(i) the Pass Through Amount in respect of the relevant Pass Through Event; and

(ii) the date from, and period over which, the Pass Through Amount may be applied, and notify MTC in writing of the Commission's decision.

(c) If the Commission does not give a notice to MTC under clause 3.3(b)(ii) within the Assessment Period, then the Commission is taken to have notified MTC of its determination that:

(i) the relevant Pass Through Event has occurred (or will occur); and

(ii) the Pass Through Amount and form of the Pass Through Amount are as specified in the Notice of Proposed Pass Through given by MTC under clause 3.2.

3.4 Relevant Factors

In making a determination under clause 3.3, the Commission must seek to ensure that the financial effect on MTC associated with the Pass Through Event concerned is economically neutral taking into account:

(a) the relative amounts of revenue capped transmission services provided by MTC;

(b) the time cost of money for the period over which the Pass Through Amount is to be applied;

(c) the financial effect on MTC associated with the provision of revenue capped transmission services attributable to the Pass Through Event and the time at which the financial effect took place or will take place;

(d) in relation to a Change in Taxes Event:

(i) the amount of any increase or reduction in another tax, rate, duty, charge, levy or other like or analogous impost intended to offset in whole or in part the relevant Change in Tax Event and the manner in which and the period of over which that increase or reduction occurs; and

(ii) the amount included in the operating expenses or other cost inputs of MTC's revenue cap;

(e) in relation to a Terrorism Event, any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with:

(i) the Terrorism Event; or

(ii) any action taken in controlling, preventing, suppressing or in any way relating to the Terrorism Event;

(f) in relation to an Insurance Event:

(i) the amount of any loss, damage, cost or expense of any nature directly or indirectly caused by, resulting from or in connection with the Insurance Event and including without limitation:

(A) the cost of any material increase or decrease in premium paid or payable by MTC beyond that provided for in MTC's revenue cap;

(B) the cost of any material increase or decrease in deductible paid or payable by MTC beyond that provided for in MTC's revenue cap; and

(C) if an Insurance Event occurs and MTC either does not continue the relevant Insurance or continues the Insurance on different terms, losses resulting from any uninsured event or partially uninsured event where that event would have been insured or fully insured by Insurance at the date of the Determination, and

(ii) the economic consequences for MTC of a decision to Self Insure.

(g) in relation to a Service Standards Event, the financial effect on MTC associated with any increased or decreased costs or risks (including in the nature, scope or asymmetry of risks) resulting from the Service Standards Event including, where relevant, an appropriate self insurance allowance relating to the increased risks.

3.5 Application of Pass Through Amount

Within 10 business days of MTC receiving or taking to have received a notice under clause 3.3 determining a Pass Through Amount, MTC will notify its Relevant Coordinating Network Service Providers of:

(a) the Pass Through Amount; and

(b) the date from and period over which the Pass Through Amount will apply,

4. INFORMATION DISCLOSURE

4.1 Non-confidential information

Unless designated by MTC as confidential, the Commission may disclose publicly information provided to it by MTC under clauses 2.1 and 3.2 of these Pass Through Rules.

4.2 Confidential information

If MTC designates as confidential any information provided to the Commission under clauses 2.1 and 3.2 of these Pass Through Rules, the Commission will not disclose publicly that information, subject to clause 6.2.6 of the Code.

5. DEFINITIONS

The terms in these Pass Through Rules have the same meaning as in Chapter 10 of the National Electricity Code and in MTC’s Application to the Commission of 18 October 2002.

5.1 Additional Definitions

Applicable Law means any legislation, delegated legislation (including regulations), codes, licences or guidelines relating to the provision of one or more revenue capped transmission service, and includes the National Electricity Code and the National Electricity Law.

Assessment Period means 40 business days from the date the Commission receives from MTC a Notice of Proposed Pass Through or a period not longer than 80 business day determined by the Commission at its discretion.

Authority means any government or regulatory department, body, instrumentality, minister, agency or other authority or any body which is the successor to the administrative responsibilities to that department, body, instrumentality, minister agency or authority, and includes the Essential Services Commission of Victoria, the Essential Services Commission of South Australia, VENCorp, ElectraNet SA, NEMMCO, NECA and the Commission.

Change in Taxes Event means:

(a) a change in the way or rate at which a Relevant Tax is calculated (including a change in the application or official interpretation of Relevant Tax);

(b) the removal or imposition of a new Relevant Tax,

to the extent that the change or imposition:

(c) occurs after the date of the Determination; and

(d) results in a change in the amount MTC is required to pay or is taken to pay (whether directly, under any contract or as part of the operating expenses or other cost inputs of MTC's revenue cap) by way of Relevant Taxes.

Determination means the determination of the Commission setting the revenue cap for MTC in relation to the regulatory control period commencing on [***date to be inserted when known***].

Insurance means insurance whether under a policy or a cover note or other similar arrangement:

(a) for risks of the sort for which MTC was covered at the date of the Determination;

(b) for amounts not less than amounts underwritten in favour of MTC at the date of the Determination; and

(c) on terms, including without limitation terms specifying deductibles payable and any applicable exclusions, no less favourable to MTC than the terms in place at the date of the Determination.

Insurance Event means where one or more of the following circumstances occurs:

(a) where Insurance in respect of any risk becomes unavailable to MTC;

(b) where Insurance in respect of any risk becomes unavailable to MTC at reasonable commercial rates;

(c) where Insurance in respect of any risk becomes unavailable to MTC on terms which are at least as favourable to MTC as those generally available at the date of the Determination;

(d) where the cost of Insurance (including, without limitation, premiums and deductibles) in respect of any risk becomes materially higher or lower than the cost of Insurance at the date of the Determination; or

(e) where an insurance benefit payment to MTC under its Insurance in respect of any risk is reduced by a deductible amount.

Non-contestable Capital Works Event means any event where MTC is required under a connection or network service contract or under Applicable Law to undertake non-contestable capital works.

Notice of Proposed Pass Through means a notice described in clause 3.2.

Pass Through Amount means a variation to MTC's revenue cap as a result of a Pass Through Event determined in accordance with these Pass Through Rules.

Relevant Coordinating Network Service Provider means VENCorp for the Victorian region and ElectraNet SA for the South Australian region.

Relevant Tax means any tax, rate, duty, charge, levy or other like or analogous impost that is:

(a) paid, to be paid, or taken to be paid by MTC in connection with the provision of transmission services, or:

(b) included in the operating expenses or other cost inputs of MTC's revenue cap;

(c) but excludes

(d) income tax (or State equivalent tax) or capital gains tax;

(e) penalties and interest for late payment relating to any tax, rate duty, change, levy or other like or analogous impost;

(f) fees and charges paid or payable in respect of a Service Standards event;

(g) stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;

(h) any tax, rate, duty, charge, levy or other like or analogous impost that replaces the taxes or charges referred to in (c) to (f).

Self Insure means where MTC elects following the occurrence of an Insurance Event to self insure for all or part of a risk of the sort for which MTC previously maintained Insurance.

Service Standards Event means a decision made by the Commission or any other Authority or any introduction of or amendment to an Applicable Law after the date of the Determination that:

(a) has the effect of:

  (i) imposing or varying minimum standards on MTC relating to revenue capped transmission services that are different to the minimum standards applicable to MTC in respect of revenue capped transmission services at the date of the Determination;

  (ii) altering the nature or scope of services that comprise the revenue capped transmission services;

  (iii) changing MTC's connection or revenue recovery contracts with ElectraNet SA, VENCorp or SPI PowerNet, or their successors, in a manner that is beyond MTC's reasonable control;

  (iv) substantially varying the manner in which MTC is required to undertake any activity forming part of revenue capped transmission services from date of the Determination; or

  (v) increasing or reducing MTC's risk in providing the revenue capped transmission services, and

(b) results in MTC incurring (or being likely to incur) materially higher or lower costs in providing revenue capped transmission services than it would have incurred but for that event.

Terrorism Event means an act, including but not limited to the use of force or violence and/or the threat thereof, of any person or group(s) of persons, whether acting alone or on behalf of or in connection with any organisation(s) or government(s), which from its nature or context is done for, or in connection with, political, religious, ideological, ethnic or similar purposes or reasons, including the intention to influence any government and/or to put the public, or any section of the public, in fear.

5.2 References to certain general terms

Unless the contrary intention appears, a reference in these Rules to:

(a) (**variations or replacement**) a document (including these Rules) includes any variation or replacement of it;

(b) (**clauses, annexures and schedules**) a clause, annexure or schedule is a reference to a clause in or annexure or schedule to these Rules;

(c) (**reference to statutes**) a statute, ordinance, code or other law includes regulations and other instruments under it and consolidations, amendments, re-enactments or replacements of any of them;

(d) (**singular includes plural**) the singular includes the plural and vice versa;

(e) (**person**) the word "person" includes an individual, a firm, a body corporate, a partnership, joint venture, syndicate, an unincorporated body or association, or any Authority;

(f) (**successors**) a particular person includes a reference to the person's successors, substitutes (including persons taking by novation) and assigns;

(g) (**meaning not limited**) the words "include", "including", "for example" or "such as" are not used as, nor are they to be interpreted as, words of limitation, and, when introducing an example, do not limit the meaning of the words to which the example relates to that example or examples of a similar kind;

(h) (**reference to anything**) anything (including any amount) is a reference to the whole and each part of it.

5.3 Headings

Headings (including those in brackets at the beginning of paragraphs) are for convenience only and do not affect the interpretation of these Rules.