Preliminary View

Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue

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Commissioners
Bhojani
Willett
McNeill
Martin

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Glossary

AC	Alternating Current
ACG	Allens Consulting Group
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
Code	National Electricity Code
Commission	Australian Competition and Consumer Commission
CRA	Charles River Associates
DC	Direct Current
DRP	Draft Statement of Principles for the Regulation of Transmission Revenues
DSM	Demand Side Management
ECCSA	Electricity Consumers Coalition of South Australia
ESC	Essential Services Commission (Victoria)
ESCOSA	Essential Services Commission Of South Australia
EME	Edison Mission Energy
ESIPC	Electricity Supply Industry Planning Council
EUAA	Energy Users Association of Australia
EUCV	Energy Users Coalition of Victoria
HVDC	High Voltage Direct Current
IOWG	Interconnector Options Working Group
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRPC	Inter-Regional Planning Committee
MAR	Maximum Allowed Revenue
MNSP	Market Network Service Provider
MTC	Murraylink Transmission Company
MTP	Murraylink Transmission Partnership

MW	Megawatts
NECA	National Electricity Code Administrator
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NSP	Network Service Provider
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
Opex	Operating and maintenance expenditure
QCA	Queensland Competition Authority
QNI	Queensland – New South Wales Interconnector
RAB	Regulated Asset Base
RAV	Regulatory Asset Value
SEIL	Saha Energy International Ltd
SNI	South Australia – New South Wales Interconnector
SRMC	Short Run Marginal Cost
TEA	TransEnergie Australia
TEUS	TransEnergie United States
TNO	Transmission Network Owner
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System
USE	Un-served Energy
VENCorp	Victorian Energy Networks Corporation
VoLL	Value of Lost Load
WACC	Weighted Average Cost of Capital

Executive Summary

Introduction

Murraylink is a privately funded electricity transmission asset owned by the Murraylink Transmission Partners (MTP) and operated by the Murraylink Transmission Company (MTC) on behalf of MTP. It includes the world's longest underground power cable (180 kilometres) and connects the Victorian and South Australian regions of the National Electricity Market (NEM) transferring power between the Red Cliffs substation in Victoria and the Monash substation in South Australia. Murraylink's current rated capacity is 180 megawatts (MW).

Murraylink operates in the NEM as a market network service provider (MNSP) relying on the spot price differential between the Victorian and South Australian regions of the NEM, or contractual arrangements, to earn revenue.

On 18 October 2002, the Australian Competition and Consumer Commission (Commission) received an application from MTC, seeking a decision by the Commission that:

- the network service provided by Murraylink be determined to be a 'prescribed service' for the purposes of the National Electricity Code (code); and
- for the provision of this prescribed service, MTP be eligible to receive the maximum allowable revenue from transmission customers (through a coordinating network service provider (NSP)) for a regulatory period commencing from the date of the Commission's final decision on MTC's application to 31 December 2012.

Clause 2.5.2(c) of the code gives the Commission discretion to determine whether a market network service should be converted to a prescribed service, and adjust a revenue cap accordingly:

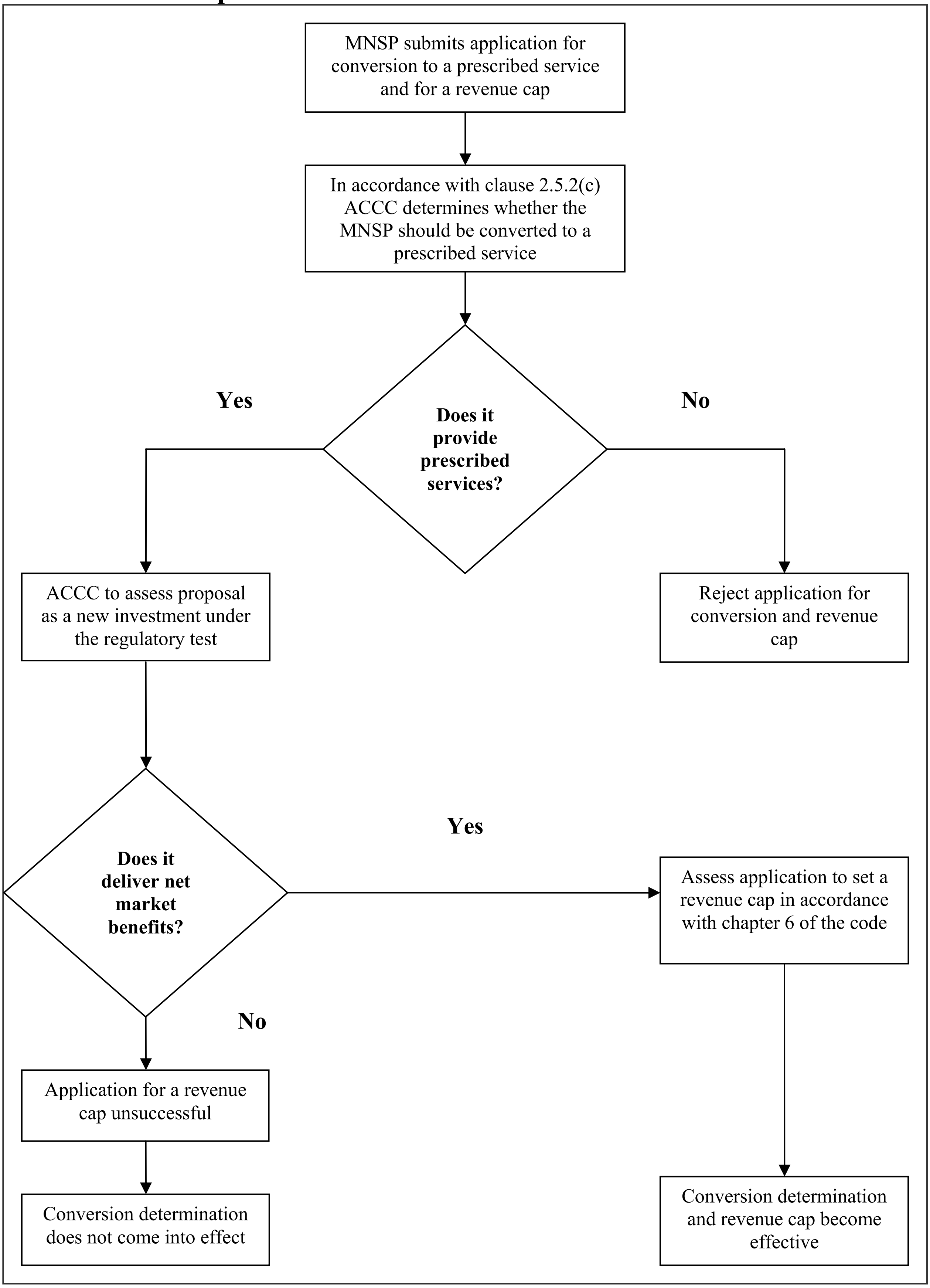
> If an existing network service ceases to be classified as a market network service it may at the discretion of the Regulator or Jurisdictional Regulator (whichever is relevant) be determined to be a prescribed service or prescribed distribution service in which case the revenue cap or price cap of 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.

Process for assessing MTC's conversion application

The code does not set out specific criteria for conversion of a MNSP to a prescribed service. As a result, on 5 February 2003, the Commission released an issues paper providing interested parties with guidance on the administration of the relevant provisions of the code as well as outlining its thinking at the time on how it would proceed with the assessment of MTC's conversion application. It also engaged PB Associates and Saha Energy International (SEIL) to assist it in its review of the application. The Commission received 38 submissions in response to MTC's application, the Commission's issues paper and its consultancy reports. These are listed in Appendix A.

The process that the Commission has adopted in assessing MTC's conversion application is to first determine whether the assets can be classified as a prescribed service. For this, the Commission has looked to the relevant provisions and definitions contained in the code. The Commission then assessed whether Murraylink delivers net benefits to the market using the regulatory test. This process ensures that an MNSP will not accrue a material advantage by bypassing the relevant provisions in chapter 5 of the code. For interconnectors that deliver net benefits to the market the Commission will set an opening asset value approximating an Optimised Depreciated Replacement Cost (ODRC) valuation. This process is contained in Figure 1 which is intended to aid the reader's understanding of the Commission's process.

Figure 1 – Conversion process



Conversion

The code does not provide any criteria on how the Commission must exercise its discretion in assessing conversion applications. Clause 2.5.2(c) provides, inter alia, that a market network service may at the discretion of the Regulator be determined to be a prescribed service. Therefore, the determination of whether a market network service is to be a prescribed service is at the Commission' discretion. There are no express limits on the exercise of the Commission' discretion, other than that the network ceases to be classified as a market network service. No criteria are provided to guide the regulator in exercising its discretion.

The Commission has focused its assessment on whether or not the service is a prescribed service for a number of reasons.

Firstly, the Commission notes that the intention of the NECA Working Group was to provide a right for an MNSP to apply for conversion to ensure that investment is not inefficiently inhibited:

> …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.

Secondly, the authorisation of the Network Pricing and MNSP code changes containing the conversion provisions provided a signal that conversion would be a possible option for an MNSP, and that the Commission would consider conversion on a case by case basis. Given the NECA Working Group's comments it is inconsistent for the Commission to now set what arguably would be a higher threshold for assessing MTC's conversion application.

Thirdly, the approach adopted by the Commission will help ensure consistency between its considerations of MTC's application for conversion and its approval of other forms of regulated investments. In this case, it has assessed Murraylink in the same way that other new investments undertaken by TNSPs are assessed. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass the intent of the provisions contained in chapter 5 of the code. This will ensure that the regulated revenue entitlement is appropriate, and that transmission customers will not bear the costs of inefficient investment.

Finally, the conversion option enables MNSPs to reduce the risks of their investment by applying for the determination of regulated revenue. By reducing the risks of investment faced by MNSPs, conversion encourages transmission investment in the NEM.

Code obligations

The relevant clauses in the code are 2.5.2(c), which deals with the process of conversion, and 6.2.4 which sets out the process and mechanisms by which the Commission must administer revenue caps to prescribed services.

“Prescribed Services” are defined in chapter 10 of the code (glossary) as:

> “Transmission services provided by transmission network assets or associated connection assets to which the revenue cap applies”.

The definition of transmission services is:

> “The services provided by a *transmission system* associated with the conveyance of electricity which include *entry services*¸ *transmission use of system service*, and *exit services* and *new network services* which are being provided by part of a *transmission system*.”

Chapter 10 defines a revenue cap (relating to transmission) as:

> “In Parts B and C of Chapter 6, the maximum allowed revenue for a year determined by the Regulator for prescribed services applicable to a Transmission Network Owner”.

In considering the above code definitions the Commission has developed a working definition of a prescribed service to be a service that is not:

a) a Market Network Service;

b) found to be contestable under clause 6.2.4(f); or

c) excluded from the revenue cap under a more light handed regime imposed by the Commission pursuant to clause 6.2.3(c).

The Commission believes that Murraylink satisfies criteria (a) and (c) of its working definition. However, with regard to the second criterion, the code presents different tests for determining contestability. In the first instance, clause 6.2.4(f) requires the Commission to consider whether a service is contestable.

Clause 6.2.4(f) of the code states:

> *Revenue caps* set by the ACCC are to apply only to those services, the provision of which in the opinion of the ACCC are not reasonably expected to be offered on a *contestable* basis.

However, there is a tension between that test and the code glossary’s definition of a contestable service which is defined as:

> In relation to *transmission services* or *distribution services*, a service which is permitted by the laws of the relevant participating jurisdiction to be provided by more than one *Network Service Provider* as a contestable service or on a contestable basis.

In order to consider the question of contestability, the Commission conducted a competition analysis to determine whether Murraylink operates in a market that is characterised by effective or potential competition. The competition analysis determined that there are high barriers to entry, limited substitution, and little countervailing power to facilitate further market entry to compete against Murraylink. Therefore, the Commission concludes that Murraylink is not a contestable service.

The Commission, therefore, considers that Murraylink satisfies the working definition of a prescribed service, and that MTC is subsequently entitled to receive regulated revenue.

Commission's jurisdiction

Under clause 2.5.2(c) of the code, if an existing network service ceases to be classified as a market network service, it may at the discretion of the Commission be determined to be a prescribed service. The Commission is currently of the view that its ability to exercise its discretion to determine a service to be a prescribed service does not arise until an existing network service ceases to be classified as a market network service. That is, the classification change is a pre-condition to the exercise of the Commission's power.

Accordingly, the Commission has released its current views as a Preliminary View, and proposes to subsequently release a Position Paper setting out its position on MTC's conversion application and revenue cap. The Commission does not propose to issue a formal decision until it is advised of the details of the Murraylink service ceasing to be classified as a market network service.

Regulatory test

The regulatory test and conversion

The regulatory test is an important tool in the Commission's decision making process for a number of reasons. As noted previously, as far as possible the Commission is seeking a consistent approach between its considerations of MTC's application for conversion and its approval of other forms of regulated investments. In this case, it has assessed Murraylink in the same way that other new investments undertaken by TNSPs are assessed. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass the intent of the provisions contained in chapter 5 of the code. As is the case for new investments made by other TNSPs, the regulatory test will also provide the Commission with an initial value for the purpose of setting a revenue cap.

Power transfers

The power transfer capability of Murraylink is a critical input into the calculation of the market benefits of the interconnector. The greater the transfer capability of Murraylink then the greater its potential market benefits as assessed under the regulatory test. In the case of Murraylink additional augmentations are required in NSW and Victoria in order for it to achieve its stated power transfer capabilities.

As confirmed by PB Associates, in the absence of MTC's proposed augmentations Murraylink's power transfer capability will be reduced to 180 MW. However, in response to the concerns raised by PB Associates, MTC submitted additional information, in association with VENCorp, supporting its 220 MW transfer capabilities. Further work undertaken by PB Associates supports MTC's claimed power transfer capabilities provided additional augmentations proposed by VENCorp plus those proposed in the MTC application are in service. The Commission is therefore satisfied the MTC achieve can achieve its 220MW. The Commission understands that this transfer capability is consistent with the transfer capabilities that Murraylink could achieve if unbundled SNI was in place[1]. The Commission also understands that SNI, running in parallel with Murraylink would not deliver any more capacity than either one of these options operating in isolation.

Gross Market Benefits

In calculating the gross market benefit of a proposed interconnector or augmentation option the regulatory test requires sensitivity analysis be undertaken with respect to the key input variables. It also requires, amongst other things, reasonable forecasts of a range of variables including electricity demand, the value of energy to electricity consumers and efficient operating and capital costs of other sources of energy.

The Commission's consultant, SEIL, concluded that the methodology employed by MTC in estimating Murraylink's gross market benefits appears to be broadly consistent with guidelines set out under the regulatory test, and was applied consistently with the analysis undertaken for the South Australia - New South Wales (SNI) and SNOVIC interconnection. Where there was divergence from the SNI and SNOVIC analysis, SEIL did not believe that the divergence was unreasonable. However, it recommended that further sensitivity analysis be conducted to determine the appropriateness of the gross market benefits.

In line with SEIL's recommendation, the Commission requested that further sensitivity work be undertaken by MTC to ensure the robustness of MTC's analysis. Based on the additional information provided to the Commission, Murraylink's gross market benefits fall within the range from $136 million to $300 million, with the median value around $190 million.

Alternative projects

A regulatory test assessment requires that the augmentation maximises the net present value of the market benefit having regard to a number of alternative projects.

The alternative projects identified by MTC are:

1. Buronga to Monash 275 kV AC mostly overhead transmission line, with substation augmentations at Buronga and Monash and undergrounding through the bookmark biosphere (following a similar route to the interconnector portion of the SNI)

2. Red Cliffs to Monash 140 kV DC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash and undergrounding

[1] Unbundled SNI is generally taken to be SNI without the physical link between Buronga in New South Wales and Robertstown in South Australia. It includes augmentations to the New South Wales and Victorian Networks.

through the Lyrup State Forest and on the approach to the Red Cliffs and Monash substations

3. Red Cliffs to Monash 220 kV AC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash and undergrounding through the Lyrup State Forest and on the approach to the Red Cliffs and Monash substations

4. Robertstown to Monash 275 kV AC overhead transmission line, Heywood to South East substation 275 kV AC overhead transmission line, with substation augmentations at Robertstown, Monash, Heywood and South East substation, and series capacitors at Tailem Bend

5. Generation in South Australia and the Riverland area; and

6. Demand side management.

In its report SEIL stated that stronger justification should be provided for both the need for, and cost of, underground cables for the alternative projects. The Commission is sensitive to the increasing emphasis on undergrounding transmission lines and has therefore consulted with various Government departments. Based on advice from SA Planning, it has formed the following view:

- an overhead transmission line through the Bookmark Biosphere and Ramsar regions, similar to the route taken by Alternative 1, would be questionable from an environmental perspective

- although Murraylink and Alternatives 2 and 3 traverse populated areas and farming communities, there is not a similar imperative for these transmission lines to be undergrounded as in densely populated areas.

The Commission concurs with Murraylink's proposed undergrounding for alternative 1, but at this stage does not believe that undergrounding would be required for alternatives 2 and 3. The Commission will therefore reduce the level of undergrounding proposed by MTC for these projects.

A number of interested parties raised concerns with the inclusion of phase shifting transformers for alternatives 1, 3 and 4. Most parties argue that phase shifting transformers are only required where controllability is desirable and that these costs were included by MTC to ensure that the alternatives provided the same level of service as Murraylink, thereby inflating the cost of these projects. Information provided by MTC indicates that the benefits of controllability are comparable to the costs. The Commission has therefore adjusted the cost of the alternatives to reflect the reductions in the phase shifting transformer and associated spares elements. These adjustments are outlined in table 1.

Other adjustments made by the Commission to the cost of the alternative projects include reductions in the contingency allowance, as recommended by SEIL, and associated reductions in the interest during construction and profits and overheads because of the reduced capital costs. Operating and maintenance expenditure (opex) costs are based on 1.5% of capital costs.

Table 1 Regulatory cost of alternative projects

	Alternative 1	Alternative 2	Alternative 3	Alternative 4
MTC's proposed capital costs	$235.49	$190.18	$189.38	$194.90
less undergrounding	$0	$36	$56	$0
less phase shifting transformers	$19	$0	$19	$19
Add contingency based on P50 rather than P75	$4.92	$6.68	$6.91	$3.51
Less difference of interest during construction	$8.34	$3.93	$6.65	$7.43
Less difference of profit and overheads	$0.33	$0.00	$0.55	$0.40
Commission's calculated capital cost	**$212.66**	**$157.31**	**$114.42**	**$171.48**
Add lifecycle opex costs	$30.65	$22.93	$16.95	$24.91
Commission's calculated regulatory cost	**$243.31**	**$180.25**	**$131.37**	**$196.39**

As outlined in Table 1 the Commission's proposed amendments to the cost of the alternative projects suggests that Alternative 3, which is an overhead AC line between Red Cliffs and Monash, is the lowest cost alternative. This cost is less than MTC's proposed regulatory asset value of $176 million.

While other alternatives were proposed in a number of submissions the Commission's analysis of these alternatives indicates that their costs were typically higher than those of MTC's proposed alternatives after the Commission's adjustments. Further, a number of parties argued that SNI should be considered an alternative project by the Commission. However, the Commission believes that the main elements of SNI are captured in alternative 1.

Net market benefits

A new interconnector or an augmentation option satisfies the regulatory test if it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. Based on the Commission's analysis, the interconnector which maximises the net market benefits is Alternative 3, which delivers net market benefits under most credible scenarios ranging from $5 million[2] in the lowest cost scenario to $269 million[3] under the realistic bidding scenario with average net market benefits close to $60 million in the median scenarios. The Commission will therefore use the alternative 3 for the purpose of setting MTC's revenue cap.

Maximum Allowed Revenue

MTC has proposed that the regulatory period should be of 10 years' duration. The Commission is of the view that a 10 year regulatory period is appropriate in this case for two reasons. The opex allowance for Murraylink is substantially below that requested for MTC in its application because the Commission has adopted alternative 3's opening asset value and thus Alternative 3's opex. The Commission is of the view that it is unlikely there is scope for substantial efficiency gains. Furthermore, MTC has not proposed a substantial capex program. The Commission therefore proposes to set MTC's revenue until June 2013. The Commission has added half a year to the regulatory period proposed by MTC to align MTC regulatory control period with other TNSPs. This provides a regulatory control period of 9 and ¾ years.

Cost of Capital

In determining MTC's revenue cap, the Commission must have regard to MTC's WACC. A number of submissions note the differences in the cost of capital parameters adopted by MTC compared to those adopted by the Commission in its previous revenue cap decisions for ElectraNet and SPI PowerNet, and called for consistency for the MTC revenue cap. With the exception of the 10 year bond rate, the Commission concurs with the views of interested parties and has calculated a post-tax nominal return on equity of approximately *11.17* per cent, which equates to a post-tax nominal vanilla WACC of *8.45* per cent. In arriving at those figures, the Commission has adopted:

- a nominal risk free interest rate of *5.19* per cent, reflecting the short term average yield on ten year Commonwealth Government bonds;
- a real risk free rate of *3.02* per cent based on the short term average yield on ten year capital indexed bonds;
- an expected inflation rate of *2.11* per cent derived from the difference between the two yields;
- a debt margin of *1.45* per cent above the nominal risk free interest rate resulting in a nominal pre-tax cost of debt of *6.64* per cent.
- an equity beta of 1, derived from the mid-point of a feasible range for the equity beta of between 0.75 and 1.25.

The Commission's post-tax nominal return on equity of *11.17* per cent lies below MTC's proposal of a nominal post tax return on equity of 12.15 per cent. This largely reflects the prevailing market conditions and MTC's contention that it requires a

2 $136 million (gross market benefits) less $131 million (life cycle project cost)
3 $310 million less $131 million (life cycle project cost)

higher rate of return to reflect the level of risk faced by its network from competing energy sources.

Table 2 provides a comparison of the cost of capital parameters proposed by MTC and the Commission.

Table 2 Comparison of cost of capital parameters proposed by MTC and the Commission

Parameters	MTC's proposal	Commission's parameter
Gearing ratio (D/V) %	60%	60%
Asset beta β_a	0.60	0.4
Debt beta	0.2	0
Equity beta	1.13	1.00
Debt margin (over R_f) %	1.50%	1.45%
Market risk premium (R_m-R_f) %	6.00%	6.00%
Nominal risk free interest rate (R_f)%	5.4%	5.19%
Expected inflation rate (F) %	2.2%	2.11%
Cost of debt $R_d = R_f +$ debt margin %	6.90%	6.64%
Value of imputation credit	45%	50%
Nominal post tax return on equity	12.15%	11.17
Post tax nominal WACC	6.97%	6.74%
Pre tax nominal WACC	9.96%	8.96%
Pre tax Real WACC	7.76%	6.72%
Vanilla WACC	9.00%	8.45%

Opening asset base

MTC proposes a regulatory asset value of $176.906 million. It derives its value from the gross market benefits, assuming a medium growth scenario, of $212.24 million less $37.334 million which is the life-cycle operating and maintenance costs. MTC's proposal is above the lowest cost option of $114.42 million which is derived from a modified Alternative 3. The Commission therefore proposes that for the purposes of the setting a revenue cap MTC's opening asset valuation will be set at $114.42 million.

Based on the opening asset base and capex the Commission's modelling of MTC's asset base is outlined in Table 3.

Table 3 MTC's MAR to 30 June 2013 ($ nominal million)

	Financial year ending 30 December										
	2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Opening asset base	114.42	114.41	114.14	113.82	123.41	122.88	122.27	121.58	120.81	119.95	119.00
Capital expenditure	-	-	-	10.26	-	-	-	-	-	-	-
Economic depreciation	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
Closing asset base	114.41	114.14	113.82	123.41	122.88	122.27	121.58	120.81	119.95	119.00	118.48
Return on capital	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03

1 This is data for a three month period, 1 October 2003 to 31 December 2003.
2 This is data for a six month period, 1 January 2013 to 30 June 2013.

Opex

Consistent with the Commission's proposed approach of referencing the costs of the lowest cost alternative project for the purposes of determining MTC's MAR, the Commission will include an opex allowance based on the costs of Alternative 3 of $19.37 million ($nominal) over the regulatory period.

Pass-through rules

MTC's application and subsequent information proposes that the pass-through mechanism would operate for five categories of events:

- a Change in Taxes Event;
- a Service Standards Event;
- a Non-contestable Capital Works Event;
- a Terrorism Event; and
- an Insurance Event.

With the exception of the Non-contestable Capital Works Event the Commission approves MTC's proposals.

Total Revenue

Based on the various elements of the building block approach, the Commission propose a smoothed revenue allowance that increases from $2.97 million from 1 October 2003 to 31 December 2003 to $12.25 million, $12.49 million, $12.74 million, $12.99 million, $13.25 million, $13.51 million, $13.78 million, $14.05 million and $14.33 million in the subsequent full years of the regulatory period (Table 4).

Table 4 MTC's MAR to 30 June 2013 ($ nominal million)

	Financial year ending 30 December										
	2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Return on capital	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03
Return of capital	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
Operating expenses	0.43	1.82	1.86	1.90	1.94	1.98	2.02	2.06	2.11	2.15	1.10
Estimated taxes payable	0.22	0.98	1.00	1.02	1.12	1.14	1.16	1.18	1.20	1.21	0.62
Less value of franking credit	0.11	0.49	0.50	0.51	0.56	0.57	0.58	0.59	0.60	0.61	0.31
Unadjusted revenue allowance	2.97	12.25	12.33	12.69	13.46	13.54	13.62	13.70	13.77	13.84	6.95
Smoothed MAR	**2.97**	**12.25**	**12.49**	**12.74**	**12.99**	**13.25**	**13.51**	**13.78**	**14.05**	**14.33**	**6.95**

1 This is data for a three month period, 1 October 2003 to 31 December 2003.
2 This is data for a six month period, 1 January 2013 to 30 June 2013.

In arriving at its Preliminary View the Commission notes that its proposed revenue cap is approximately 50 per cent lower than MTC's proposed revenue cap.

The difference between MTC's proposed MAR and the Commission's MAR is largely the result of:

- a lower value for the RAB arising from the selection of a adjusted alternative 3
- different cost of capital parameters used in deriving the post-tax nominal return on equity and
- a significant reduction in opex.

Service Standards

The Commission, in association with Sinclair Knight Merz (SKM) has developed five key service performance measures on which to base its service standards performance incentive scheme. While PB Associates concurs that only circuit availability is required for a transmission system comprising only a single circuit interconnector it recommends that circuit availability be subdivided into:

- planned availability
- forced availability during peak periods and
- forced availability during off-peak periods

and associated performance targets be set for each category rather than a single overall target. Taken together, the three targets represent a cumulative unavailability of 1.77%. Given the importance of interconnectors in the NEM and the limited history of Murraylink's operation the Commission considers PB Associates' recommended performance incentive targets are appropriate.

Commission's Preliminary View

The Commission's Preliminary View can be summarised as follows

In accordance with its obligations under the code, the Commission determines Murraylink's services to be classified as prescribed service and therefore proposes conversion of Murraylink from a market network service to a prescribed service. As a result, the Commission will determine a maximum allowable revenue (MAR) for MTC, in accordance with Chapter 6 of the code subject to the outcomes of the regulatory test.

The Commission is satisfied that if the additional augmentations are in place then Murraylink's rated capacity will be 220 MW.

The Commission accepts that Murraylink delivers gross market benefits ranging from $136 million to $300 million under most credible scenarios, with the median being around $190 million.

The Commission's proposed amendments to the cost of the alternative projects suggests that Alternative 3, which is an overhead AC line between Red Cliffs and Monash, is the lowest cost alternative. As a result, Alternative 3 satisfies the regulatory test and, for the purposes of determining MTC's regulatory asset value and opex costs the Commission proposes to use adjusted Alternative 3 in determining MTC's MAR.

The Commission will grant opex based on 1.5% of the lowest cost alternative. It will also allow pass through for the following events:
- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

On the basis of its building block approach the Commission has determined a revenue cap applying for a regulatory period of 10 years for MTC that increases from approximately $2.97 million from 1 October 2003 to 31 December 2003, $12.25 million from 1 January 2004 to 31 December 2004 to $14.33 million for 31 December 2012. For the period 1 January 2013 to 30 June 2003 a revenue of $6.95 million.

Introduction

The National Electricity Code (code) establishes two frameworks for the development of network services in the National Electricity Market (NEM), regulated and unregulated network services. Regulated, or prescribed, transmission services earn regulated revenue determined by the Commission in accordance with chapter 6 of the code. Unregulated assets earn revenue from trading in the wholesale electricity market in accordance with chapter 3 of the code. In particular, market network service providers (MNSPs) rely on the spot price differential between two interconnected regions, or contractual arrangements, to earn revenue.

The National Electricity Code Administrator's (NECA) Working Group on Interregional Hedges and Entrepreneurial Interconnectors (NECA Working Group) developed the framework for the governance and participation of unregulated interconnectors in the NEM. The NECA Working Group recommended that an MNSP have an option to apply to convert to regulated status, at which time a revenue entitlement would be assessed.

The Network Pricing and MNSP code changes, which introduced the MNSP arrangements, including the option to apply for conversion, were authorised by the Commission in September 2001. Clause 2.5.2(c) of the code gives the Commission discretion to determine whether a market network service should be converted to a prescribed service and, adjust a revenue cap accordingly:

> 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 light of the option to apply for conversion, on 18 October 2002, the Commission received an application from MTC, on behalf of MTP, seeking a decision by the Commission that:

- the network service provided by Murraylink be determined to be a 'prescribed service' for the purposes of the National Electricity Code (code); and
- for the provision of this prescribed service, MTP be eligible to receive the maximum allowable revenue from transmission customers (through a coordinating network service provider (NSP)) for a regulatory period commencing from the date of the Commission's final decision on MTC's application to 31 December 2012.

This chapter sets out:

- the process that the Commission will adopt when assessing a conversion application

- the review and public consultation processes followed by the Commission in reaching its decisions;
- an overview of the Murraylink transmission network; and
- the structure of this document.

Process for assessing MTC's conversion application and regulation of transmission revenues.

The code does not set out specific criteria for conversion of a MNSP to a prescribed service. As a result, on 5 February 2003, the Commission released an issues paper providing interested parties with guidance on the administration of the relevant provisions of the code as well as outlining its thinking at the time on how it would proceed with the assessment of MTC's conversion application. It also engaged PB Associates and SEIL Energy International (SEIL) to assist it in its review of the application. The Commission received 38 submissions in response to MTC's application, the Commission's issues paper and its consultancy reports (refer to Appendix A).

The process that the Commission has adopted in assessing MTC's conversion application is to first determine whether the assets can be classified as providing a prescribed service. For this, the Commission will look to the relevant provisions and definitions contained in the code. If the interconnector is determined to provide a prescribed service the Commission will then assess whether it delivers net benefits to the market using the regulatory test. This ensures that an MNSP will not accrue a material advantage by bypassing the provisions in chapter 5 of the code. For interconnectors that deliver net benefits to the market the Commission will set an opening asset value approximating an Optimised Depreciated Replacement Cost (ODRC) valuation.

Conversion Assessment

The code does not provide any criteria on how the Commission must exercise its discretion in assessing conversion applications. The Commission therefore proposes to limit its considerations to assessing whether the service should be a prescribed service in accordance the code provisions. The relevant clauses in the code are 2.5.2(c), which deals with the process of conversion, and 6.2.4 which sets out the process and mechanisms by which the Commission must administer revenue caps to prescribed services.

"Prescribed Services" are defined in chapter 10 of the code (glossary) as:

> "Transmission services provided by transmission network assets or associated connection assets to which the revenue cap applies".

The definition of transmission services is:

> "The services provided by a *transmission system* associated with the conveyance of electricity which include *entry services¸ transmission use of system service*, and *exit services* and *new network services* which are being provided by part of a *transmission system*."

Chapter 10 defines a revenue cap (relating to transmission) as:

> "In Parts B and C of Chapter 6, the maximum allowed revenue for a year determined by the Regulator for prescribed services applicable to a Transmission Network Owner".

Under clause 6.2.3(c) the Commission is responsible for determining whether a network service can be excluded from a revenue cap under a more light-handed regime imposed by the Commission.

In considering the above code definitions the Commission has developed a working definition of a prescribed service to be a service that is not:

a) a Market Network Service;

b) found to be contestable under clause 6.2.4(f); or

c) excluded from the revenue cap under a more light handed regime imposed by the Commission pursuant to clause 6.2.3(c).

While typically, a market network service that is converting will satisfy criteria (a) and (c) of the Commission's working definition, the second criteria presents different tests of contestability in the code. In the first instance, clause 6.2.4(f) requires the Commission to consider whether a service is contestable.

Clause 6.2.4(f) of the code states:

> *Revenue caps* set by the ACCC are to apply only to those services, the provision of which in the opinion of the ACCC are not reasonably expected to be offered on a *contestable* basis.

However, there is a tension between that test and the code glossary's definition of a contestable service which is defined as:

> In relation to *transmission services* or *distribution services*, a service which is permitted by the laws of the relevant participating jurisdiction to be provided by more than one *Network Service Provider* as a contestable service or on a contestable basis.

In order to consider the question of contestability, the Commission has conducted a competition analysis to determine whether a market network service operates in a market that is characterised by effective or potential competition.

Regulatory test assessment

An applicant who proposes to establish a new large network asset must follow the procedures outlined in clause 5.6.6 of the code and, in particular, must undertake a regulatory test assessment. To ensure that market network services applying to convert to prescribed services do not accrue a material advantage over prescribed services the Commission will ensure that the MNSP must follow the process set out in the regulatory test. The regulatory test is based on the traditional cost-benefit analysis framework with key features that include

- reference to net public benefits

- calculating the net benefits of the various options with reference to the underlying economic cost savings and not with reference to pool price outcomes which may be distorted by market participants exercising market power
- excluding from the analysis the costs and benefits associated with competitive, non-electricity, market activities as the test is to be used to assess the merits of regulated electricity network assets
- including in the analysis only those environmental impacts that governments or their environment agencies have sought to redress
- using the discount rate that would be used by participants in the contestable markets and
- relying on forecasts of future market behaviour based on both assumptions of a competitive market as well as actual market behaviour.

A new interconnector or an augmentation option satisfies the regulatory test if it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios.

Form of transmission revenue regulation

In its role as the regulator of NEM transmission revenues, the code requires the Commission to adopt a regulatory process which prevents monopoly pricing, provides a fair return to network owners and creates incentives for managers to pursue ongoing efficiency gains through cost reductions. In achieving these aims the Commission is aware of the need to ensure compliance costs are minimised and that the regulatory process is objective, transparent and as light handed as possible.

Consistent with the proposals contained in its draft *Regulatory Principles*, the Commission has adopted an accrual building block approach in the present revenue cap decisions. In implementing this framework, the 'post-tax nominal' accrual building block approach calculates the MAR as the sum of the return on capital, the return of capital, an allowance for operating and maintenance (non-capital) expenditure and income tax payable; that is:

MAR = return on capital + return of capital + opex + taxes ± service standards

= (WACC * WDV) + D + opex + taxes ± service standards

where:	WACC	=	post-tax nominal weighted average cost of capital;
	WDV	=	written down (depreciated) value of the asset base;
	D	=	depreciation allowance;
	opex	=	operating and maintenance expenditure
	taxes	=	income tax liability allowance and
	service standards	=	ACCC performance incentive scheme

Furthermore, in implementing the CPI-X incentive mechanism the revenue cap will increase each year in line with inflation but decrease by a smoothing factor, X.

Review and public consultation processes

The key aspects of the review of the MTC conversion application which have occurred to date are as follows:

- *On 18 October 2002, MTC submitted its application for the Commission's consideration*: The application outlines its views on key elements of the regulatory test and revenue cap setting processes. The application is available on the Commission's website.

- *The Commission engaged consultants to review Murraylink's power transfer capabilities, its regulatory test assessment and its service standards regime.* PB Associates was engaged to conduct the power transfer and service standards consultancies, while SEIL Energy International was engaged to review MTC's regulatory test application. Copies of the PB Associates and SEIL reports are available on the Commission's website.

- *On 5 February 2002 the Commission released an issues paper addressing MTC's application*: The issues paper set out the Commission's initial views on its administration of the relevant provisions of the code with regard to conversion. Interested parties were invited to make submissions on the issues paper. A copy of the issues paper is available on the Commission's website.

- *The Commission conducted discussions with MTC and interested parties*: The information provided by MTC subsequent to its submission is included in this preliminary view.

- *The Commission made this preliminary view on 14 May 2003*.

The Commission now invites submissions on this Preliminary View. Written submissions, or submissions on disk, in Word 7.0 compatible format, can be sent to:

Mr Sebastian Roberts
A/g General Manager
Regulatory Affairs - Electricity
GPO Box 520J
MELBOURNE VIC 3001

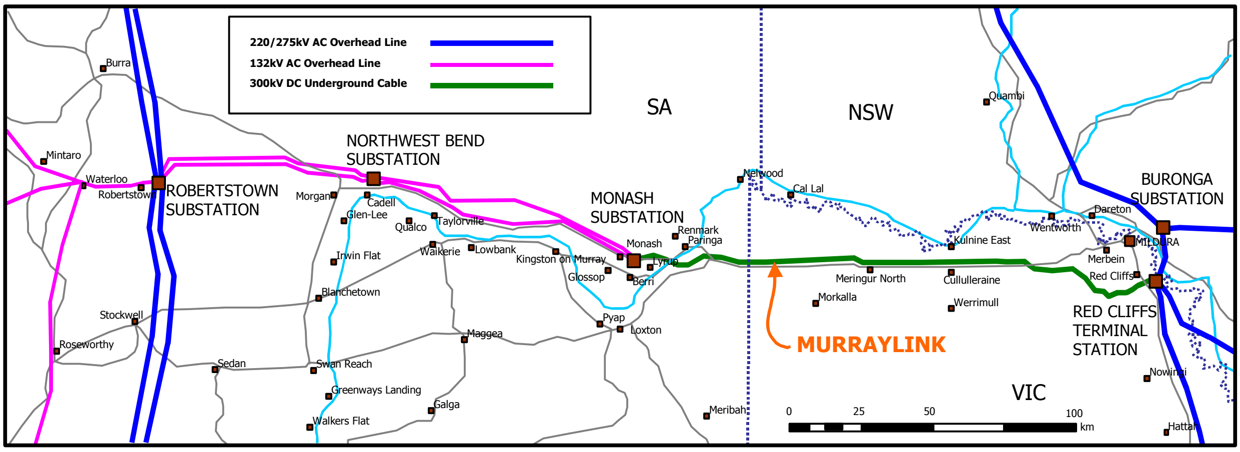
Submissions close on 11 July 2003.

Overview of the Murraylink transmission network

Murraylink is a privately funded electricity transmission asset owned by MTP and operated by MTC on behalf of MTP. It includes the world's longest underground power cable and connects the Victorian and South Australian regions of the National Electricity Market transferring power between the Red Cliffs substation in Victoria and the Monash substation in South Australia. Murraylink currently has a rated capacity of 180 MW. It came into operation in early October 2002.

The Murraylink route for the transmission cables is a total of 180 kilometres, approximately 145 kilometres in Victoria and 35 kilometres in South Australia, along roads and highways.

Figure 1 Murraylink Cable Route



Murraylink operates in the NEM as an MNSP relying on the spot price differential between the Victorian and South Australian regions of the NEM, or contractual arrangements, to earn revenue.

Murraylink utilises the latest ABB high voltage direct current ("HVDC") transmission technology known as HVDC Light. This technology has been specifically designed to meet both high reliability and technical standards and has been used previously in Australia, the United States of America and Sweden. TransEnergie Australia (TEA) and TransEnergie US (TEUS) have used the technology for the Directlink project in Australia and the Cross Sound Cable project between Long Island, New York and Connecticut in the north-eastern United States of America.

The HVDC Light system consists of two elements: converter stations (one at each end of the system) that convert alternating current electrical energy ("AC") to direct current electrical energy ("DC"), or vice versa; and a pair of DC transmission cables.

Structure of this document

The remainder of this document explains the Commission's preliminary views on MTC's application for conversion and maximum allowable revenue. It is structured as follows:

- Section 1 contains the Commission's assessment of MTC's conversion application using the process described in this introduction.
- Section 2 details the regulatory test assessment containing:
  - an analysis of Murraylink's power transfer capabilities
  - a study of its gross market benefits and
  - an assessment of the costs of the alternative projects
- Section 3 concerns the Commission's revenue cap setting process. In particular it
  - deals with MTC's weighted average cost of capital (WACC)
  - sets out the Commission's assessment of MTC's RAB as at 1 October 2003;
  - outlines operating and maintenance expenditure and pass through;
  - the Commission's assessment of each element of the building block and
  - sets out the service standards appropriate to the level of the revenue cap determined.

Section 1 – Conversion of Murraylink to a prescribed service

1 Commission's assessment

1.1 Introduction

Clause 2.5.2(a) of the code enables an NSP to voluntarily classify its network services as market network services, provided that it satisfies the provisions set out in clause 2.5.2(a) of the code (Safe Harbour Provisions).

Clause 2.5.2(a) provides:

> (1) the relevant *network service* is to be provided by *network elements* which comprise a *two-terminal link* and do not provide any *prescribed service* or *prescribed distribution service*;
>
> (2) the *Network Service Provider* is registered under clause 2.5.1 in respect of the *network elements* which provide the relevant *market network service* and the *Network Service Provider* has provided an access undertaking to the *ACCC* in respect of the relevant *market network service* provided by those *network elements* as required under clause 5.2.3(a2)*;*
>
> (3) the relevant *network service* must;
>
> (A) not have ever been *a prescribed service* or *a prescribed distribution service;* or
>
> (B) be ineligible to be such a service;
>
> (4) the *connection points* of the relevant *two-terminal link* must be assigned to different *regional reference nodes*; and
>
> (5) the relevant *two-terminal link* through which the *network service* is provided;
>
> (A) does not form part of a *network loop;* or
>
> (B) must be an *independently controllable two-terminal link*,
>
> and must have a registered *power transfer capability* of at least 30MW.

The Safe Harbour Provisions are important in terms of an interconnector's physical characteristics. Interconnectors that have been developed as market network services according to the Safe Harbour Provisions are technically different to typical transmission services that are developed according to chapter 5 of the code. In turn, the physical characteristics of a market network service that is seeking conversion are relevant to the Commission's considerations of what constitutes an efficient facility in the NEM.

MTC is currently registered with the National Electricity Market Management Company (NEMMCO) as an MNSP. Its application has been lodged in accordance with clause 2.5.2(c) of the code, which states that:

> 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.

The Commission is the regulator for the purposes of this clause.

Clause 2.5.2(c) indicates that an assessment of a conversion application consists of two parts.

1. *Conversion to a prescribed network service*
   - Chapter 2 allows an MNSP to voluntarily notify NEMMCO that the network services provided are no longer classified as market network services, and also allows the Commission to determine the network service to be a prescribed service.
2. *Revenue cap determination*
   - Clause 2.5.2(c) allows the regulator to adjust the NSP's revenue cap in accordance with chapter 6 of the code.
   - Chapter 6 of the code sets out the Commission's obligations when setting a revenue cap. In particular, clause 6.2.4 of the code sets out the form and mechanism of revenue capping of a transmission service.

Commission's jurisdiction to make a 'conversion' determination

Under clause 2.5.2(c) of the code, if an existing network service ceases to be classified as a market network service, it may at the discretion of the Commission be determined to be a prescribed service. The Commission is currently of the view that its ability to exercise its discretion to determine a service to be a prescribed service does not arise until an existing network service ceases to be classified as a market network service. That is, the classification change is a pre-condition to the exercise of the Commission's power.

Accordingly, the Commission has released its current views as a Preliminary View, and proposes to subsequently release a Position Paper setting out its position on MTC's conversion application and revenue cap. The Commission does not propose to issue a formal determination until it is advised of the details of the Murraylink service ceasing to be classified as a market network service.

1.2 Submissions from interested parties

Conversion of Murraylink

The Essential Services Commission of South Australia (ESCOSA), Energy Users Association of Australia (EUAA), Headberry Partners[4], TransGrid, ElectraNet SA (ElectraNet) and AGL all indicate support for conversion if it is shown that there is a net benefit to customers, given that customers will bear the increased TUoS costs arising from Murraylink's conversion. TransGrid submits that to make that

[4] Headberry Partners prepared a joint submission on behalf of ElectraNet, the Electricity Consumers Coalition of South Australia, and The Energy Users Coalition of Victoria.

assessment, the Commission needs to know the benefits to the market that would arise from the conversion of Murraylink from a market network service to a prescribed service.[5]

Headberry Partners, TransGrid, ElectraNet, Integral Energy, the NSW Minister of Energy (NSW Government) and Ergon believe that the Commission should not allow conversion in circumstances where an MNSP has been a poor investment and wishes to convert to regulated status to receive guaranteed financial returns. ElectraNet notes the NECA Working Group's report which stated that:

> "…the conversion option should not shield the proponent from normal commercial risks, eg 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 need for the facility at the time of the application, rather than guaranteeing a return on the original capital cost".[6]

The EUAA, Integral and Edison Mission Energy (EME) note that generators do not enjoy the same comfort. Integral submits that the Commission should reject MTC's application for conversion, and that an efficient outcome would follow from private bargaining between MTC and its customers. Ergon states that the conversion option places a 'floor' under any risks of failure as an MNSP but does not 'cap' the earnings of successful entrepreneurial investments. In principle, Santos supports the Commission's approach to assessing the conversion application but disagrees with allowing Murraylink to convert.

The South Australian Electricity Supply Industry Planning Council (ESIPC), EUAA, NSW Government, and EME all contend that allowing conversion to occur may present opportunities for MNSPs to 'game' the regulatory approval process. The EUAA and ESIPC submit that merchant projects might be built based on strong initial cash flows, but in the longer run become unprofitable, thus inducing the proponent to apply for conversion to regulated status with zero net market benefits.

Headberry Partners submits that the financial commitment of a market based augmentation recognises that there is a benefit to the market, much of which it is anticipated by the asset owner will be captured for itself. Thus, Headberry Partners submits, conversion is effectively a transfer of risk from the asset owner to users of the augmentation.

1.2.1 Commission's discretion under clause 2.5.2(c)

ElectraNet urges the Commission to be guided in its exercise of discretion by the comments of the NECA Working Group on the inclusion of the conversion option and the regulated revenue entitlement.

TransGrid submits that the Commission must adopt a principled and transparent method in evaluating MTC's application, and that the Commission cannot exercise its discretion mechanistically by simply adopting a modified version of the regulatory

[5] This issue is addressed in more detail in Regulatory Asset Valuation chapter.
[6] NECA Working Group on Inter-regional hedges and entrepreneurial interconnectors, February 1999.

test. TransGrid submits that the Commission retains the discretion to reject MTC's application on reasonable grounds including factors such as whether the conversion would allow the applicant to make up for an imprudent investment or obtain windfall gains by strategic conversion from unregulated to regulated status.

Headberry Partners contends that the lack of guidance from the code implicitly places a more stringent obligation on the regulator to explain the reasons for the exercise of its discretion.

1.2.2 Incremental benefits of conversion

ElectraNet, Ergon Energy, ESIPC, the NSW Government, NERA, and TransGrid suggest that an alternative approach to deriving Murraylink's regulatory asset value (RAV) would be to apply the regulatory test according to the incremental benefits of Murraylink's conversion to regulated status. This will be referred to as the "incremental benefits" approach. ElectraNet states that under MTC's approach, any benefit to the market which might arise as a result of the conversion will be fully offset by the regulatory costs used to determine its revenue cap.

Headberry Partners and the EUAA submit that before a RAV is determined for Murraylink, the Commission must specifically assess whether Murraylink will increase the technical performance of the network in a way that could not be achieved by alternative means for a lesser cost.

EME argues that as Murraylink already exists (and by definition a consumer/producer surplus exists), converting Murraylink to regulated status has no net economic benefit, as there is no change in consumer/producer surplus. Therefore, EME believe that the Commission should reject MTC's application, or alternatively approve it with a capitalised value of $0.

1.2.3 Response from the applicant

Conversion of Murraylink

The Allen Consulting Group (ACG) prepared a report on behalf of MTC in response to the economic issues raised in submissions. ACG argues that the 'escape clause' contained in clause 2.5.2(c) is necessary to promote investments in MNSPs.

ACG states:

> "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."[7]

ACG also argues that the administration of the NEM rules, as well as the rules themselves, can have a substantial impact on a project's viability. Therefore, ACG

[7] The Allen Consulting Group, *Report to Murraylink Transmission Company, Application for conversion of Murraylink to a prescribed service, commentary on the economic issues*, April 2003.

submits, it is not unreasonable for an ‘escape clause’ to exist for MNSPs, and for it to be factored into MTC’s business plan. ACG also contends that, in the exercise of its discretion, the Commission may take into account whether the regulatory test is satisfied, being the test that is relevant to applicants seeking prescribed status for new large network assets under clause 5.6.6 of the code.

Incremental benefits

ACG argues that on close analysis, the incremental benefits methodology is unreasonable. It states that an implication of the incremental benefits methodology, as expressed by NERA, is that the regulatory cost for Murraylink would be set at the ODV, *less* the benefits that Murraylink creates as an MNSP that it is unable to capture. 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 costs. ACG argues that this methodology is counter-intuitive to the background leading to the inclusion of the clause 2.5.2(c) ‘escape clause’ in the code.

ACG argues that more generally, the ‘incremental benefits’ valuation methodology has the effect of giving market participants a right to continue to receive for free, the benefits that they are technically ‘free-riding’ on. ACG contends that there is no economic reason for allowing this to continue, and that the appropriate response would be to correct this market failure, using the rules that were put in place to address such a market failure, should it arise.

Alternatively, ACG submits that the relevant question for the Commission is whether conversion would advance economic efficiency, and the economy overall. It also argues that when analysed objectively, it is difficult to see how conversion would reduce efficiency. ACG argues that efficiencies arising from Murraylink’s conversion might come from two sources. Firstly, any incentive or ability to withhold Murraylink’s capacity from the market would disappear if Murraylink were a regulated interconnector; and secondly, operating Murraylink on an open access basis might also provide for a more certain environment for the planning of the national electricity grid.

1.3 Commission's considerations

1.3.1 Framework for whether a service is eligible to be a prescribed service

MTC's application includes the expectation that if Murraylink passes the regulatory test, then it will be determined to be a prescribed service, and the regulatory cost of Murraylink will also constitute the Regulatory Asset Value of Murraylink:

"…MTP has an expectation that if it proposes a regulatory asset value at which Murraylink satisfies the Regulatory Test, the Commission will:

- determine that the network service being provided by Murraylink should be a prescribed network service; and
- allow MTP to incorporate Murraylink into its regulatory asset base at that regulatory asset value." [8]

In its Issues Paper, the Commission indicated that it would have regard to the regulatory test in considering the conversion application. After giving further consideration to the issue and having had regard to submissions received, the Commission is of the view that assessment of the application involves a two step process: conversion and a revenue cap decision. The application of the regulatory test will be relevant for the latter step. Therefore, the Commission believes that there is a threshold question of whether Murraylink should be converted to a prescribed service, before addressing a potential regulatory asset value for Murraylink. The Commission proposes that conversion applications be assessed in accordance with certain provisions of the code. The relevant clauses in the code are 2.5.2(c) which deals with the process of conversion, and 6.2.4, which sets out the process and mechanisms by which the Commission must administer revenue caps to prescribed services.

The Commission's discretion

Clause 2.5.2(c) provides, inter alia, that a market network service may at the discretion of the Regulator be determined to be a prescribed service. Therefore, the determination of whether a market network service is to be a prescribed service is at the Commission' discretion. There are no express limits on the exercise of the Commission' discretion, other than that the network ceases to be classified as a market network service. No criteria are provided to guide the regulator in exercising its discretion.

The approach adopted by the Commission is to determine whether Murraylink falls into the category of "prescribed service" as defined by the code. The remainder of this chapter explains how the Commission has defined the term prescribed service and how it has assessed Murraylink against that definition.

Other issues were raised in submissions that could be considered as part of the assessment of the conversion application. For example, whether an MNSP should

[8] Murraylink Transmission Partnership, *Application for conversion to a prescribed service and maximum allowable revenue for 2003-12*, 18 October 2002, p26.

demonstrate that the NEM has changed since its decision to construct a market network service, and the overall benefits to the public from conversion.

However, the Commission is of the view that it is appropriate to focus its assessment on whether or not the service is a prescribed service for a number of reasons.

Firstly, the Commission notes that the intention of the NECA Working Group was to provide a right for an MNSP to apply for conversion to ensure that investment is not inefficiently inhibited:

> …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.

Secondly, the authorisation of the Network Pricing and MNSP code changes containing the conversion provisions provided a signal that conversion would be a possible option for an MNSP, and that the Commission would consider conversion on a case by case basis. Given the NECA Working Group's comments it would be inconsistent for the Commission to now set what arguably would be a higher threshold for assessing MTC's conversion application.

Thirdly, the approach adopted by the Commission will help ensure consistency between its considerations of MTC's application for conversion and its approval of other forms of regulated investments. In this case, it has assessed Murraylink in the same way that other new investments undertaken by TNSPs are assessed. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass the intent of the provisions contained in chapter 5 of the code. This will ensure that the regulated revenue entitlement is appropriate, and that transmission customers will not bear the costs of inefficient investment.

Finally, the conversion option enables MNSPs to reduce the risks of their investment by applying for the determination of regulated revenue. By reducing the risks of investment faced by MNSPs, conversion encourages transmission investment in the NEM.

Prescribed service

One of the eligibility criteria under the Safe Harbour Provisions is that an intending MNSP must never have been a prescribed service, nor be eligible to be such a service. This is consistent with clause 2.5.2(b), which provides that a transmission service that is classified as a market network service is not a prescribed service, and the code does not permit an MNSP to impose any charges for use of a market network service under chapter 6 of the code.

Although the safe harbour provisions in clause 2.5.2(a) of the code effectively exempt MNSPs from classification as a prescribed service, the question the Commission is considering is whether Murraylink would be a prescribed service if it were not covered by the safe harbour provisions. That is, does Murraylink exhibit characteristics that are consistent with the definition of a prescribed service? If Murraylink fits within the definition of a prescribed service, the Commission intends to allow it to be classified as a prescribed service (i.e. convert), and then address the matter of a revenue cap for Murraylink.

"Prescribed Services" are defined in chapter 10 of the code (glossary) as follows:

> "Transmission services provided by transmission network assets or associated connection assets to which the revenue cap applies".

The definition of transmission services is as follows:

> "The services provided by a *transmission system* associated with the conveyance of electricity which include *entry services*¸ *transmission use of system service*, and *exit services* and *new network services* which are being provided by part of a *transmission system*."

Chapter 10 defines a revenue cap (relating to transmission) as:

> "In Parts B and C of Chapter 6, the maximum allowed revenue for a year determined by the Regulator for prescribed services applicable to a Transmission Network Owner".

In considering the above definitions it becomes apparent that neither definition sets out which services are to be subject to a revenue cap and are therefore to be prescribed services. However, chapter 6 of the code provides some guidance. Part B of chapter 6 sets out two circumstances where transmission services will be *excluded* from a revenue cap:

i. clause 6.2.4(f) provides that revenue caps set by the Commission are to apply only to those services, the provision of which in the opinion of the Commission are not reasonably expected to be offered on a contestable basis; and

ii. clause 6.2.3(c) provides that the Commission is responsible for determining whether the state of competition warrants the application of a form of regulation that is more light handed than revenue capping, and if so, the form of that regulation.

Given the above, a 'working definition' of a prescribed service is a service that is not:

(a) a Market Network Service;

(b) excluded from the revenue cap under a more light handed regime imposed by the Commission pursuant to clause 6.2.3(c) ; or

(c) found to be contestable under clause 6.2.4(f).

Murraylink as a market network service

With respect to the first limb, once Murraylink ceases to be classified as a prescribed service, it would be eligible to be determined to be a prescribed service.

More light-handed regime?

With respect to the second limb, the Commission does not consider that sufficient competition would exist to warrant the application of a more light-handed regime.

Does Murraylink provide a contestable service?

With respect to the third limb of this definition, clause 6.2.4(f) of the code refers to services not reasonably expected to be offered on a contestable basis.

Clause 6.2.4(f) states that

> "Revenue caps set by the ACCC are to apply only to those services, the provision of which in the opinion of the ACCC are not reasonably expected to be offered on a contestable basis".

In turn, chapter 10 defines contestable as

> "a service which is permitted by the laws of the relevant participating jurisdiction to be provided by more than one Network Service Provider as a contestable or on a competitive basis."

This definition is not particularly instructive as the relevant jurisdictions (South Australia and Victoria) do not explicitly specify which services can be provided by more than one service provider.

Therefore, the Commission must consider what contestable means. Guidelines developed by the Victorian Office of the Regulator-General (now Essential Services Commission (ESC)), the Independent Pricing and Regulatory Tribunal of NSW and the Queensland Competition Authority provide useful guidance on this. In each case the guidelines exclude services from regulation where the market for those services is contestable. Contestability was defined by the ESC as describing a market that would be characterised by effective or potential competition.[9]

The ESC drew upon the ACCC's merger guidelines to develop guidelines for assessing whether a market is characterised by effective competition. If a service is not effectively competitive the ESC goes on to determine whether it is potentially competitive. Table 1 sets out the criteria used by the ESC. The Commission has adopted such a framework and assessed Murraylink against these criteria. Table 1 provides comments against each of the criteria. Overall this assessment indicates that Murraylink would fall into the category of prescribed service. A discussion of the comments against these criteria follows.

[9] Office of the Regulator-General, Victoria, *Electricity Distribution Excluded Services, Final Approach,* September 2001.

Table 1.1

Criteria for effectively competitive market	Competition Concern	Comment
Number of competing providers	Yes	• Two interconnectors into SA, but still some market power concerns, eg., when one is constrained. • Only one provider for Riverland support
Degree of countervailing power	Yes	• Limited
Availability of substitutes	Yes	• Heywood upgrade not considered to be as beneficial to the SA market as Riverland augmentation. • Generation in Riverland is costly and Demand Side Management unlikely. • An MNSP is insufficient to support all of the Riverland.
Criteria for potentially competitive market		
Nature and extent of barriers to entry	Yes	• Economies of scale to incumbent regulated interconnector. • Further MNSP entry unlikely. • Development costs for interconnectors are significant. • NEMMCO assessment shows that unbundled SNI will yield greater net benefits than SNI.

Effective competition

Competition is typically thought of in terms of the number of competing players, where the greater the number of competitors, the more competitive the market. However, regardless of the number of competitors, a market with "effective competition" means that there is limited scope for a supplier to wield market power, and regulation is likely to be unnecessary. As the ESC's criteria show, effective competition can occur when barriers to entry are low, close substitutes are available, or where customers have a significant degree of countervailing power. Similarly, a potentially competitive market is one in which firms do not exercise market power that might otherwise exist, because there is a credible threat of potential competition from new entrants. The concept of "potential competition" is similar to the conventional definition of contestability.

In considering whether Murraylink is a contestable service the Commission needs to first define the market in which it operates. There are two possibilities for this. At a broad level, Murraylink connects the Victorian and South Australian electricity grids, via an interconnector with a rated capacity of 220 MW.

South Australia is expected to be the importing region at most times. Therefore the relevant market may be for the transfer of power into South Australia.

Assuming the market to be the transfer of power into South Australia via an interconnector, an assessment of effective/potential competition can be made. For the purposes of clause 6.2.4(f) of the code, the service in question is Murraylink. The only competing provider would be the Heywood interconnector (Heywood). Murraylink and Heywood transfer electricity between Victoria and South Australia at a rated capacity of 220 MW and 500 MW respectively and have the benefit of significant economies of scale as the incumbent operators in this market. Furthermore, circumstances where either interconnector is operating at capacity would also enhance its market power.

The Commission notes that Heywood and the Queensland-New South Wales Interconnector (QNI) are prescribed services even though there are two interconnectors between their respective regions. This would suggest that the only reason that Murraylink is not a prescribed service is because of its current classification as an MNSP under the code's safe harbour provisions.

A new entrant in a transmission market typically faces barriers to entry including incumbent operators' economies of scale, lumpy investment, and in some cases, the risk of not recovering the sunk costs of new entry (barriers to exit). That is, in order to compete against the incumbents, a new entrant must develop an interconnector that is large enough for the new entrant to achieve its own economies of scale. Furthermore, the minium efficient scale of the market may be such that new entry is precluded entirely.

Substitutes for transmission into South Australia appear to be limited. While generation is an alternative option for increasing electricity supply, a generator does not provide similar technical services as an interconnector, and Murraylink in particular.

An upgrade of the Heywood interconnector has been proposed as a potential substitute for new interconnection. However, the Commission's consultants advise that an upgrade would not provide a sufficient level of service to the South Australian region, nor would it alleviate constraints in the Snowy/NSW or Snowy/Victoria interconnections. By contrast, Murraylink in conjunction with augmentations in NSW and Victoria will address these constraints.

As the preceding paragraphs indicate, transmission into South Australia is an essential service with few substitutes. Countervailing power constitutes the ability of consumers to bypass a service through their consumption decisions. In the context of electricity, demand-side management would be a form of countervailing power. However, demand-side management would need to occur on a scale that is comparable to Murraylink's 180 MW rated capacity. Given the unlikelihood that this will occur, countervailing power/demand-side management does not seem to be a credible influence on Murraylink's market conduct.

On the basis of this assessment, the Commission believes that the conditions for potential and effective competition in the market for transmission services into South Australia are not satisfied.

The second possible market definition is the Riverland region of South Australia. The Commission is of the view that, currently, the needs of the South Australian market are best met through transmission augmentation in the Riverland, suggesting that this may be a more accurate market definition for the purposes of the service that Murraylink provides. In December 1999 the ESIPC published the Riverland discussion paper, which detailed the forecast need for augmentation of the transmission system, based on the forecast electricity demand at the Berri and North West Bend connection points. Relevantly, Murraylink enters the South Australian region at Berri, and consequently connects the Riverland region with the Victorian electricity grid. In terms of competing providers, it would appear that none currently exist as Heywood is neither a competitor nor a substitute for Riverland support.

As noted above, there appear to be high barriers to the development of another interconnector into South Australia. In the Riverland, the potential for new entry depends on whether there is sufficient demand to support the development of a second interconnector in the region. The Commission notes the concerns raised in submissions that if both Murraylink and SNI proceed to be developed as regulated interconnectors, then electricity customers, particularly in South Australia, would be required to pay TUoS based on the combined RAV of both projects. ESIPC suggests that the benefits of both projects could be achieved by one interconnector. The Commission expects that based on forecasts of demand in the Riverland region, it is questionable whether a second interconnector in the Riverland region would be commercially viable, particularly given the high start-up costs.

With regard to substitutes, the regulatory tests conducted for both Murraylink and SNI, and studies by ESIPC conclude that generators and MNSPs cannot economically provide Riverland support on a sustainable basis.[10] Therefore, regulated interconnection between the Riverland and either Victoria or NSW is generally accepted to be the most cost-effective option for Riverland support. The relevant question arising from this analysis is whether it would be economic to develop another regulated interconnector in this area. As noted above, the Commission expects that this would be unlikely.

As with the assessment of a market for interconnection into South Australia, countervailing power on a comparable level to Murraylink's rated capacity is not a viable option in the Riverland region.

The Commission's assessment suggests that the conditions for effective or potential competition are either weak or not present under both market definitions. Consequently, the Commission's assessment is that under either market definition, Murraylink cannot reasonably be expected to be offered on a contestable basis.

Other considerations

The assessment against the ESC's criteria is supported by the principles and objectives of the code, particularly the chapter 6 regime for the regulation of transmission revenues, which are underpinned by the Part IIIA access regime. The

[10] The Electricity Supply Industry Planning Council, *Transmission system major augmentation review: Riverland Region Supply System, Review of Proposals, Recommendations*, July 2000.

objectives of the transmission revenue regulatory regime are set out in clause 6.2.2, including the following:

- an efficient and cost-effective regulatory environment;
- *prevention of monopoly rent* extraction by TNOs/TNSPs;
- an environment which fosters *an efficient level of investment* within the transmission sector; and upstream and downstream of the transmission sector;
- an environment which fosters *efficient use of existing infrastructure*;
- *promotion of competition* in upstream and downstream markets and promotion of competition in the provision of network services where economically feasible;
- reasonable and well defined regulatory discretion which permits an *acceptable balancing of the interests of TNOs/TNSPs, transmission network users and the public interes*t as required of the ACCC under the provisions of Part IIIA of the Trade Practices Act (emphases added).

The Commission believes that these principles and objectives offer further guidance on whether Murraylink should be converted to a prescribed service. The Commission's considerations in the context of these objectives are set out below.

Firstly, as noted above, the Commission has a responsibility to foster an efficient level of investment within the transmission sector. The Commission fulfils this responsibility by determining regulated revenue that enables the service provider to receive a return on an efficient mix of productive inputs. Hence, if Murraylink were converted, the Commission's views on whether Murraylink constitutes an efficient level of transmission investment would be dealt with through the application of the regulatory test and its use in the determination of a revenue cap.

Several interested parties contend that the conversion process enables an MNSP to receive a guaranteed revenue stream for a poor investment. Indeed, the conversion option enables MNSPs to reduce the risks of their investment by applying for the determination of regulated revenue. By reducing the risks of investment faced by MNSPs, conversion encourages transmission investment in the NEM. When the conversion option originated, the NECA Working Group 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.

The process for assessing MTC's conversion application is consistent with the intent of the NECA Working Group. The assessment process incorporates the application of the Commission's DRP, wherein the asset valuation methodology does not accommodate inefficient investment. As foreshadowed by the NECA Working Group, the revenue entitlement for Murraylink will be based on its ongoing value to the market as a prescribed service. The Commission considers that this methodology provides a safeguard against MNSPs receiving regulated revenue for inefficient or 'gold-plated' investments.

The regulatory regime should also promote an environment that fosters the efficient use of existing infrastructure, the promotion of competition in upstream and downstream markets, and the promotion of competition in the provision of network services where economically feasible. The Commission believes that allowing Murraylink to operate as a regulated service enables these conditions to be met. While the Commission also questions the *extent* that MTC can currently exercise market power through Murraylink (as an MNSP), the improvements outlined by ACG provide an example of how existing infrastructure can be used more efficiently. ACG contends that:[11]

1. Murraylink's conversion to a regulated interconnector would remove any incentive or ability to withhold its capacity from the market, and so preclude any such inefficiency; and
2. Operating Murraylink on an open-access basis may also provide for a more certain environment for the planning of the national electricity grid. ACG states that this reflects the fact that all of Murraylink's capacity (subject to relevant constraints) would be available for the independent operator to use as the system dictates rather than the available capacity being determined by MTC's bidding behaviour.

The increased efficiency in the way that Murraylink is provided to the market will benefit electricity suppliers upstream and downstream of Murraylink, and subsequently, all users of those services.

1.3.2 Relevance of the regulatory test to conversion

As previously noted, the Commission's issues paper indicated that it would have regard to the regulatory test in considering MTC's conversion application. However, after giving further consideration to the issue and having had regard to the submissions received, the Commission is of the view that the primary relevance of the regulatory test is its role in determining whether the "converted" network service constitutes an efficient investment for the purpose of a revenue cap determination.

The regulatory test is the usual process for determining the economic efficiency of a new network augmentation. The market benefits limb of the regulatory test (an extended cost-benefit analysis) includes the principle that a proposed network investment must maximise prospective investments over costs. Hence, the regulatory test assesses the benefits to the entire market of specific projects. When a TNSP applies the regulatory test to a new large network asset, it determines the asset's regulatory cost (based on an engineering assessment). If the proposed augmentation

[11] The Allen Consulting Group, Op. Cit.

satisfies the regulatory test (i.e. it maximises net market benefits compared to relevant alternatives), the regulatory cost is typically included in the TNSP's asset base.

An applicant for conversion to prescribed status is not expressly required to address the matters set out in clause 5.6.6 of the code in relation to new assets, particularly whether the asset satisfies the regulatory test. Nevertheless, the Commission is of the view that, in the absence of specific criteria under clause 2.5.2(c) it is appropriate for the Commission to have regard to similar matters to those relevant to decisions made under chapters 5 and 6 of the code.

Although Murraylink is not a "new" asset for the purposes of chapter 5 of the code, MTC's conversion application seeks regulated status for Murraylink. Earlier in this section, the Commission determined that Murraylink is eligible to be classified as a prescribed service. The Commission believes that it is appropriate to apply the regulatory test in order to assess whether Murraylink delivers net benefits to the market. This process ensures that an MNSP will not accrue a material advantage from bypassing the chapter 5 provisions. The outcomes of the regulatory test will then guide the Commission in the determination of a revenue cap. This is addressed in section 3 – Maximum Allowable Revenue.

1.3.3 Incremental benefits

Several submissions support the application of the regulatory test on the basis of measuring the incremental market benefits of its conversion. According to these submissions, the methodology would involve determining the gross market benefits of Murraylink's current operation as an MNSP, compared with the market benefits of it operating as a prescribed service. The difference between these two outcomes would, according to NERA, place a cap on the regulatory cost of the converted-Murraylink.

The Commission also notes the concerns raised by interested parties that the option to apply for conversion enables MNSPs to effectively bypass the requirements of clause 5.6.6 of the code and obtain regulated status more easily. However, the Commission does not believe that the incremental benefits approach is the appropriate method for achieving symmetry between the processes used by MNSPs who apply for conversion, and transmission augmentations proposals made under chapter 5 of the code. The Commission considers that as the conversion option has been included in the code, a measurement of the market benefits of an interconnector should be aligned to the intention of the regulatory test as closely as possible.

Therefore, the Commission considers that it should determine the market benefits that result from having Murraylink operate as a prescribed service in the NEM. If the regulatory test is applied robustly, then the test should capture the impact of the operation of Murraylink as a prescribed service on a forward looking basis.

Regardless of the gross market benefits arising from Murraylink's operation as an MNSP, MTC's application of the regulatory test demonstrates that a certain level of gross market benefits can be captured from having Murraylink operate as a regulated interconnector. In quantifying the gross market benefits, the Commission has derived a regulatory cost that it considers is suitable to reflect this. It should be noted however, that in determining a RAB for Murraylink, the Commission will not have regard to the actual cost of Murraylink. Instead, the Commission will take into account the cost and configuration of what it considers to be the lowest cost option for a regulated interconnector that provides a certain level of gross market benefits. The Commission considers that this is consistent with the intent of the regulatory test and with the ODRC valuation process that the Commission uses to value and/or revalue transmission network assets. The net market benefits are discussed in section 2 of this document.

Preliminary View

In accordance with the code provisions, the Commission determines Murraylink to be a prescribed service, and therefore allows conversion of Murraylink from a market network service to a prescribed service. As a result, the Commission will determine a maximum allowable revenue (MAR) for MTC, in accordance with Chapter 6 of the code subject to the outcomes of the regulatory test.

Section 2 - Regulatory Test Assessment

The regulatory test is an important tool in the Commission's decision making process for a number of reasons. As far as possible the Commission is seeking a consistent approach between its considerations of MTC's application for conversion and its approval of other forms of regulated investments. In this case, it has assessed Murraylink in the same way that other new investments undertaken by TNSPs are assessed. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass the intent of the provisions contained in chapter 5 of the code. As is the case for new investments made by other TNSPs, the regulatory test will also provide the Commission with an initial value for the purpose of setting a revenue cap.

2.1 Power transfers

2.1.1 Murraylink's Power Transfer Capabilities

The power transfer capability of Murraylink is a critical input into the calculation of the market benefits of the interconnector. The greater the transfer capability of Murraylink then the greater its potential market benefits as assessed under the regulatory test. Therefore, it is essential for the Commission to accurately assess the transfer capability so that the economic value of Murraylink can be estimated from a market benefit analysis, and hence, the regulated revenue for MTC can be set.

2.1.2 MTC's application

MTC states that at the time Murraylink was developed, the Interconnector Options Working Group (IOWG) performed a technical assessment of the capability of Murraylink and the supporting networks in the NEM. MTC states that while many of the IOWG's findings remain current, some have been superseded by subsequent studies conducted by TransEnergie Australia (TEA) and verified by Power Technologies International (PTI).

The main findings of the TEA report can be summarised as follows:

1. In the case where spare generation is available within the Victoria region, Murraylink can deliver up to 220 MW to the South Australian region under summer peak load conditions with:

    - 1900MW being imported into the Victorian region from the NSW/Snowy regions, and
    - the implementation of the augmentations listed in chapter 4 of its study

2. In the case where no spare generating capacity is available from within the Victorian region, Murraylink can deliver up to 110 MW transfer into the South Australian region from excess NSW generation, simultaneous with 1900 MW being imported into the Victorian region from the NSW and Snowy regions across the Snowy-Victoria interconnector. The augmentations listed in

section 4 of the TEA report, the majority of which are reactive support, are required to achieve the stated power transfer capability

3. Power imports into the Victorian region from the NSW/Snowy region, and the Murraylink dispatch into South Australia, both compete for spare capacity on certain parts of the network, particularly in south-west NSW and at times power flow into the Victorian region from the NSW region is less than 1900 MW, spare generation capacity in the NSW region can be dispatched to achieve the 220 MW transfer capability

4. With runback in place, Murraylink's transfer capability for power transfers from the South Australian region to Victorian region is limited by the pre-contingent loading capability of the two 132 kV lines between Robertstown and the North West Bend. Accordingly, Murraylink's transfer capability can be expressed as

   ML <= 222 – RL (MW) (summer) To a maximum of 150MW
   ML <= 280 – RL (MW) (winter) To a maximum of 150MW

   Where:
   ML is the Murraylink transfer capability and
   RL is the Riverland load

MTC engaged PTI to conduct an independent review of TEA's transfer capability assessment. PTI's main findings can be summarised as follows:

1. PTI's studies confirm the results of TEA's studies, given the limited scenarios and technical inquiry.

2. With power supplied from the Victorian to the South Australian region, that is, in the Victorian swing bus case:

   - Murraylink can operate in a secure state at a level of 180 MW under peak load conditions, assuming some minor additional voltage support as indicated by TEA; and
   - A flow up to 220 MW on Murraylink could be made secure under peak load conditions and for all single contingency events but higher levels of voltage support and network control services (e.g run-backs) would be required.

3. With power supplied from NSW to the South Australian region, that is, in the NSW swing bus case, a secure Murraylink flow in the order of 110 MW is sustainable under peak load conditions and for all single contingency events with other minor additional voltage support also suggested by TEA.

4. The "Secure" states cited are ones which allow single contingency events without voltage collapse. For certain contingencies, subsequent run-back would be needed in order to alleviate network overload conditions.

2.1.3 PB Associates' Review

PB Associates was engaged by the Commission to review, analyse and comment on the assumptions, methodology and findings of TEA's report and the due diligence of TEA's Power Transfer Capability Report, undertaken by PTI.

The main findings and recommendations of PB Associate's review can be summarised as follows:

- Under the assumption that the findings of original IOWG assessments of Murraylink, SNOVIC and SNI were correct, and noting the findings of the PTI due diligence, PB Associates believes that the following Murraylink transfer capabilities should be achievable:
    - 2003/04 Peak summer demand, high import (1900 MW) to Victoria from Snowy / NSW, incremental generation in Victoria – Murraylink transfer capability Victoria to South Australia (South Australia) is **180 MW.** This is lower than the capability proposed by TEA.
    - 2003/04 Peak summer demand, high import (2010 MW) to Victoria from Snowy / NSW, incremental generation in NSW – Murraylink transfer capability Victoria to SA is 110 MW
    - 2003/04 Peak Riverland demand – Murraylink transfer capability South Australia to Victoria is 95 – 100 MW This assumes that the existing and additional augmentations defined in the TEA report are in service.

PB Associates notes that the 180 MW transfer capacity from Victoria to South Australia with incremental generation in Victoria is less than the 220 MW transfer capacity given in the MTC application for these conditions. PB Associates states that this difference is due to uncertainty on whether unacceptable voltage depression or collapse in the state grid region of Victoria might occur for transfers greater than 180 MW under these conditions. PB Associates recommended that further dynamic studies be performed, in consultation with VENCorp, to determine whether the full 220 MW transfer capability claimed by TEA is achievable, considering the additional augmentations proposed in the TEA report or similar. Further, PB Associates notes that these transfer capabilities assume that the existing and additional augmentations defined in the TEA report are in service.

In its review of PTI Due Diligence of TEA Transfer capability studies while the analysis performed by PTI involved independent power system studies to confirm the general findings of TEA on Murraylink's transfer capabilities, the power system model, loading and generation dispatch scenarios were provided and defined by TEA.

PB Associates indicates that the PTI due diligence confirms the requirements for the additional augmentations and runback schemes in MTC's application, it highlights that TEA's proposed additional reactive support in the SW-NSW does not appear to be confirmed by PTI studies, and voltage rise studies do not appear to have been reported. PB Associates considers that the results would be more conclusive with a contingency study with the TEA additional reactive support indicating no voltage control issues, including the over voltage criteria.

PB Associates states that it is important to note that the TEA proposed additional reactive support indicated to PTI at the time of the studies had changed slightly from that proposed in the TEA report. PB Associates notes that these changes are due to minor adjustments during the design phase resulting from new information on the configuration of operation of the network. TEA also points out that exact specification of reactive support will only be achieved during more detailed design phases and as such is likely to result in minor changes, which is supported by PB Associates.

2.1.4 Submissions from interested parties

A number of parties raised concerns about the accuracy of Murraylink's transfer capability. In particular, ESIPC argues that despite PB Associates' review of the TEA and PTI studies there has not yet been an independent verification of the physical capacity and representation of Murraylink. ElectraNet notes that its studies suggest that the capability of Murraylink will be limited to less than the 220 MW due to conditions in the Victorian region and the primary plant rating within the South Australian network.

TransGrid and EME suggest that any transfer capability that is approved should be conditional upon further dynamic studies being undertaken. Further, EME recommends that if conversion were to take place earlier, then the lower capacity values should be used in calculating the revenues.

TransGrid and ElectraNet also raise concerns about MTC's proposed network augmentations to enhance Murraylink's transfer capability. TransGrid notes that there is some commonality between the proposed augmentations and the proposed works associated with SNI. Both note that these investments will not be in operation at the time that the Commission makes its decision and should be included as future capital expenditure, rather than in the initial capital base. They also contend that if the future capex is not included in MTC's initial capital base then the market benefits should be recast as a result and that public consultation under the regulatory test would be required.

VENCorp, in studies undertaken in conjunction with MTC, concludes that 220 MW Murraylink transfer capability is feasible when the changes recommended by PB Associates are taken into account.

2.1.5 Commission's considerations

The power transfer capability of an interconnector will be dependent not only on the rated capacity of the interconnection, but also on the design of its associated controls, the state of the power system at each end of the interconnection including the system load at a particular time, and the direction of power flow. The power transfer capability may be lower than the interconnector's rated capacity and may change with time in accordance with changes in the operating state of the transmission network at each end.

In the case of Murraylink, additional augmentations are required in NSW and Victoria in order for it to achieve its stated power transfer capabilities. In response to the concerns raised by PB Associates, MTC submitted additional information in association with VENCorp which supports the 220 MW transfer capability rating. The Commission engaged PB Associates to undertake a further review of VENCorp's work, and the Commission is now satisfied that if the additional augmentations are in place, Murraylink's rated capacity will be 220 MW as submitted by MTC. While further works may be required upstream in the NSW and Victorian networks to ensure greater reliability, at peak times, the Commission believes that this will only further enhance Murraylink's transfer capacity.

Should MTC not proceed with the construction of the additional augmentations, the Commission understands that works known as Unbundled SNI will also have the same effect and enable Murraylink to transfer 220 MW into South Australia. The Commission will be working with TransGrid over the coming months in the lead up to its Revenue Cap reset to understand whether TransGrid is likely to proceed with a regulatory test assessment for Unbundled SNI.

Preliminary View

The Commission is satisfied that if the additional augmentations are in place then Murraylink's rated capacity will be 220 MW.

2.2 Gross Market Benefits

2.2.1 Introduction

In undertaking a regulatory test assessment the Commission must determine the market benefits of an interconnector. The greater the need for an interconnector the higher the gross market benefits. Market benefits are defined in the regulatory test as:

> the total net benefits of the *proposed augmentation* to all those who produce, distribute and consume electricity in the National Electricity Market. That is, the increase in consumers' and producers' surplus or another measure that can be demonstrated to produce equivalent ranking of options in most (although not all) credible scenarios

The regulatory test excludes from the analysis the costs and benefits associated with competitive, non-electricity, market activities as the test is to be used to assess the merits of regulated electricity network assets. Only the relevant costs and benefits that apply to a specific project are considered. The relevant set of costs and benefits may vary across different projects and this is entirely appropriate. Furthermore, if there are costs and benefits which cannot be measured in financial terms, or do not relate to producer or consumer surplus, such costs or benefits do not qualify to be included in the test.

In determining the magnitude of the market benefits, section (1)(b) of the notes to the regulatory test provides guidance as to the assumptions to be made. These include:

i. *electricity demand (modified where appropriate to take into account demand side options, variations in economic growth, variations in weather patterns and reasonable assumptions regarding price elasticity);*

ii. *the value of energy to electricity consumers as reflected in the level of VoLL;*

iii. *the efficient operating costs of competitively supplying energy to meet forecast demand from existing, committed and modelled projects including demand side and generation projects;*

iv. *the capital costs of committed, anticipated and modelled projects including demand side and generation projects and whether the capital costs are completely or partially avoided or deferred;*

v. *the cost of providing sufficient ancillary services to meet the forecast demand; and*

vi. *the capital and operating costs of other regulated network market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.*

2.2.2 MTC's application

As part of MTC's methodology for the calculation of its regulatory asset valuation, TransEnergie US (TEUS), on behalf of MTP, conducted a study to determine the scope and magnitude of Murraylink's market benefits. MTC engaged Charles River Associates Ltd (CRA) to comment on and assess TUES's market benefits study.

TEUS identifies the following market benefits that Murraylink can bring to the NEM:

- ***Energy and Deferred market entry benefits.*** MTC notes that Murraylink provides the opportunity for less expensive generation in one region to displace more expensive generation into another region. MTC indicates that by doing so in the short run, Murraylink continuously reduces the short run variable operating and maintenance costs, and fuel costs in the NEM. It was also noted that Murraylink also reduces the economic costs associated with voluntary load reductions and/or curtailments by reducing the expected frequency and magnitude of such events.

  MTC highlights that over time Murraylink also defers the entry of new market entry generation plant and hence defers the major capital expenditures associated with that plant.

- ***Reliability benefits***. MTC notes that probabilistic system modelling has shown that with Murraylink in service, there is less likelihood of events where electricity demand in the NEM outstrips the ability of the NEM generation and transmission system to supply that demand. The impact of these events is measured as the projected amount of unserved energy. The probabilistic system modelling has quantified the expected reductions in unserved energy associated with Murraylink. TEUS has valued unserved energy at $10,000 per mega-watt hour, which is the value of lost load set down by the code.

- ***Riverland deferred benefits***. MTC notes that Murraylink provides additional supply capacity to the Riverland area, from the summer of 2002-03, deferring the need for major transmission augmentation up to 2012-13.

TEUS's calculations provide that the gross market benefits provided by Murraylink are valued at **$214.20 million** (net present value as of 1 May 2003). The gross benefits identified are over a 39.5 years horizon.

MTC has assumed and selected alternatives that provide the same technical service and gross market benefits as Murraylink. A discussion of the alternatives and their configuration is provided in chapter 3 of this section.

Inputs and assumptions

TEUS notes that the models used in the calculation of market benefits (PROSYM and MARS) requires detailed assumptions regarding the loads, generator characteristics, fuel costs, bidding behaviour, and simplified transmission network topology and constraints. TUES indicates that the primary source of the information and assumptions have been the IRPC Stage 1 Report for SNI. All costs and financial assumptions from the IRPC Stage 1 Report were released in late 2001. Therefore model results have been inflated from September 2002 to May 1 2003 using Australian All Cities CPI for September 2002 and June 2002, plus 10 months at an annual inflation rate of 2.2% (rate developed by R.R Officer for the purpose of MTC’s cost of capital).

TEUS’s calculation of reliability benefits used un-served energy (USE) valued at $10,000/MWh to obtain the reliability benefits. However, TEUS has also inflated this figure by the inflation rate.

Murraylink’s design life is 40 years. The analysis undertaken by TEUS is for a 39.5 year period. The PROSYM modelling covers years 2003 to 2012 (modelled monthly). TEUS assumes that by 2012, the NEM is anticipated to have reached a long run equilibrium status. Energy results for calendar years 2013 to 2042 are assumed to replicate 2012 results on a monthly basis.

TEUS used the transmission limits provided in the TEA study in the calculation of the gross market benefits of Murraylink as outlined in Chapter 1 of this section. MTC notes that PTI and CRA confirmed the manner in which TEUS applied these limits as appropriate.

CRA notes that the definition of market benefits and the methodology to calculate the four main components are appropriate, reasonable and accurate and robust. CRA also states that the methodology complies with the intent of the regulatory test, and data source and assumptions presented in the TEUS report are reasonable and consistent wherever possible with those used in the IRPC study for SNI evaluation.

Discount rate

Deloitte Touche Tohmatsu (Deloitte) was engaged by MTP to determine a discount rate for the purpose of the regulatory test.

Deloitte determines a discount rate for the calculation of market benefits that is a real, pre-tax WACC. Based on its analysis, Deloitte indicates the discount rate for the analysis of a private enterprise investment in the electricity sector to be 9.25%, with a discount rate for the low and high case of 7.76% and 10.40% respectively.

Market development scenarios and sensitivities

In MTC’s original application it provided three market development scenarios. The scenarios and the respective gross market benefits are provided in the table below. The gross market benefits have been discounted at a rate of 9.25%.

Table 2.1 Cumulative present worth of Gross Market Benefits

Scenarios	Gross market benefits ($000)
Base	214,240
Low Growth	135,514
High Growth	225,589

2.2.3 SEIL Energy International report

Saha Energy International Ltd (SEIL) was engaged by the Commission to undertake a review of MTC's application of the regulatory test provided in its *Application for Conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12* dated 18 October 2002 (MTC Application). As part of this consultation, SEIL assessed TUES' Market Benefits Report for Murraylink, and CRA's comments on the TEUS's study. The findings and recommendation of this report with respect to the market benefits identified for Murraylink are presented below.

The SEIL report is available on the Commission's website.

Components of market benefits

SEIL states that the methodology in which TEUS has estimated market benefits appears to be broadly consistent with guidelines as set out under the regulatory test, and in applications of the test in recent studies referenced by TEUS and reviewed by SEIL. SEIL also states that the primary components comprising market benefits are consistent with those identified in comparable analyses undertaken for the SNI and SNOVIC interconnectors.

SEIL notes that while a number of technical aspects underlying TEUS's methodology to estimate market benefits do diverge from comparable studies, SEIL did not find that such divergence in methodology is clearly unreasonable. SEIL indicates that in most cases where there is a divergence in methodology, the treatment has been reasonably transparent, although SEIL notes that in certain cases more detailed assessment is warranted given the technical complexity of the matters considered.

SEIL is generally comfortable with the choice of modelling tools employed by TEUS in their assessment of market benefits in terms of the practical alternatives available, but notes that the findings provided are sensitive to a number of features underlying those models, and that they are subject to error estimation. However, SEIL notes that this is the case with other commonly utilised modelling tools.

Technical review of primary assumptions

Riverland deferred augmentation of network

SEIL states that TEUS has calculated the market benefits of deferring Riverland's infrastructure requirements on the basis that the SNI project does not proceed. It has calculated market benefits figures based on an adjustment of ESIPC planning horizons in line with revised ESIPC load forecasts.

SEIL tested the sensitivity of the market benefits to the timing of the expenditure on the thermal upgrade capital expenditure forward from 2013 to 2012 or 2011, when a discount rate of 9.25% is applied, reducing the total market benefits by $1.5m and $3.2m respectively. SEIL also notes that its findings compare favourably with ESIPC's findings. Under a scenario where the Murraylink interconnector is not in service, inadequate reactive power support would be provided from 2007/08 onwards.

Evaluation of time horizon

SEIL notes that there has been little consistency in this aspect of the market benefits test across similar studies. The IRPC's SNI study derived residual terms by applying a uniform series present worth factor to all streams apart from the merchant entry and Riverland deferral benefits, to effectively apply an infinite planning horizon. Furthermore, SEIL indicates that in the VENCorp Latrobe Valley to Melbourne study, benefits were calculated over a 10 year planning horizon (2002/03-2011/12).

Inflation assumptions

SEIL states that there appears to be little consistency in the way that inflation is accounted (if at all) in applications of the market benefits to date. SEIL can find no clear precedent in the applications of the market benefits test for TEUS's use of the CPI as an inflator for SRMC, the generic capital costs of new generation, the costs of voluntary load interruptions and VoLL.

SEIL further notes that TEUS's method of indexing VoLL (holding VoLL at constant real dollars, as opposed to constant nominal dollars) may have merit as a proxy for consumers' value of loss load, but could diverge from the setting of VoLL under the code.

Discount rate

SEIL notes that there is considerable divergence in regard to the setting of a discount rate. The SNI study used a real pre-tax commercial discount rate of 11% with sensitivities at 9% and 13%. VENCorp, in its Latrobe Valley to Melbourne study, used a real pre-tax discount rate of 8%, with sensitivities at 6% and 10%. SEIL illustrates, through Table 2.2, the sensitivity of the NPV of market benefits to alternative discount rates.

Table 2.2 Sensitivity of NPV of market benefits to alternative discount rates

Discount Rate	Low = 7.76%	Base = 9.25%	High 10.40%
NPV Market Benefits	$245,388m	$215,061m**	$196,412m

* Discount rates assumptions from Deloitte Touche Tomatsu Appendix C.

** Calculation of the NPV of market benefits @ 9.25% varies slightly from Application due to use of annual data by SEIL as opposed to monthly data used by TEUS. This calculation is for illustrative purposes only.

Other assumptions

With respect to generator offer behaviour, SEIL notes that for the SNI and SNOVIC market modelling, simulations were carried out using two different generator offer strategies. In the first, generators were assumed to offer into the market at short run marginal costs, and in the second, they were assumed to offer in long run marginal cost. SEIL also notes that the three market development scenarios in the TUES report differ only in their forecasts of economic growth. All scenarios use SRMC bidding for existing, committed, and market entry generators.

In regard to the assumptions regarding demand-side bidding, SEIL indicates that the IRPC has stated that a reduction in demand side participation is a benefit to the market. The SNI study assumed a value of $500/MWh for all savings in demand side participation, whichever block it was priced at. However, TUES appears to have valued the savings at the bid prices of the individual blocks i.e., $500/MWh, $1,000/MWh, $3,000/MWh, and $5,000/MWh

With respect to reliability-driven generation, SEIL notes that in the TUES study, no reliability plant is assumed to be commissioned. All unserved energy is costed at VoLL, the price at which the IRPC's SNI reliability generation would be offered into the market in the SNI market scenarios. SEIL indicates that the two approaches are equivalent, except that in the SNI study, the construction of the SNI interconnector may have added benefits of delaying the commissioning of reliability-driven generation. The TEUS study does not contemplate this additional source of benefits, but instead calculates the savings of avoided USE.

2.2.4 Submissions by interested parties

Riverland deferral benefits

ESIPC believes that the level of gross market benefits claimed by MTC is materially overstated and that an economic assessment conducted on a similar basis to that used in the recent SNI and SNOVIC 400 assessments would reveal much lower gross market benefits, possibly in the range of $0 to $30m.

ESIPC believes that Murraylink's estimate of $26 million in Riverland deferral benefits is contrary to ESIPC's assessment of that region. ESIPC believes Murraylink has not modelled demand growth accurately, and that this results in an uncertain forecast. As such, ESIPC's assessment is that Murraylink will not defer the capital needed to augment the Riverland region beyond 2007-08, thus significantly reducing Murraylink's gross market benefits. ESIPC notes that Murraylink as a regulated asset would serve to defer the capital involved in a new 275kV line, estimated at around $35m, for 5-6 years resulting in an estimated Riverland deferral benefit of approximately $10-$15m. This benefit would be significantly reduced if SNI were to proceed.

The EUAA refers to ESIPC's comments regarding deferral benefits. ESIPC queries the level of gross market benefits claimed by Murraylink ($214 million), particularly the deferral benefits of $130 million, suggesting a figure below the $32 million estimated for SNI. ESIPC also notes that the benefits of Murraylink claimed for Riverland deferral would be between zero (with SNI) and no more than $10-15 million (without SNI), not $26 million as stated in the MTC application.

NERA and TransGrid note that TUES appears to have included the Riverland augmentation in the market development scenario against which Murraylink has been assessed. However, alternative market development scenarios may not all include the Riverland augmentation. Under these scenarios, there would be no deferral benefit associated with Murraylink.

Gross market benefits of alternatives

VENCorp notes that the MTP assessment does not appear to fully consider the likelihood that each alternative has different technical characteristics, and thus are likely to provide different levels of benefits. An analysis conducted in accordance with the regulatory test would take into account the different characteristics and the benefits associated with each option.

The NSW Government notes that the Commission recognised that a variety of projects could provide similar but not identical benefits and costs to the project in question and that the issue was maximising the present value of the net market benefit, rather than obtaining the same technical service or level of gross market benefits.

Headberry Partners notes that under the regulatory test and consistent with commentary by the Commission, no two augmentations can deliver the same benefits when all locational issues, rating, design features, cost, construction, environmental, timing and operating parameters are taken into consideration. Thus, when comparing a number of alternative augmentations, it is the value achieved for the expenditure made that is the key, rather than equivalence of the benefits that needs to be sought. Furthermore, Headberry notes that when assessing an existing augmentation for conversion to regulatory status, care must be taken not to use the apparent size and benefits provided by the proposed augmentation as the basis for comparing it to alternative augmentations, because carrying out cost/benefit analysis on augmentations which may well provide similar or even lessor capacity, may result in a much higher market benefit.

NERA and TransGrid note that MTC's application does not contain information in relation to the gross market benefits of the alternative projects, but has only considered the costs. NERA further notes that it cannot be assumed that the gross benefits of alternative projects will be equal to the gross benefits calculated for Murraylink, since the benefits of alternatives need not arise from the same source. NERA also notes that this point is highlighted in the CRA report submitted as part of Murraylink's application.

Market development scenarios

NERA, TransGrid and ESIPC note that there has not been any consideration of alternative market development scenarios such as the future commissioning of Basslink, nor has there been any stress testing or sensitivity analysis using different assumptions and parameters. TransGrid notes that market development scenarios should include future transmission and generation investment changes, as both types of investment are interrelated and will impact on the gross market benefits of Murraylink.

ElectraNet notes that MTC's application is based on a very limited number of market development scenarios and alternative network and non-network options. It is the view of ElectraNet that additional market development scenarios, and alternative developments (together with the full assessment of the net market benefits associated with those developments) should be undertaken when determining the economic value of Murraylink. Appropriate sensitivity analysis should also be undertaken to test the robustness of all assumptions made.

NERA notes that MTC has failed to consider alternative market development scenarios. The role of market development scenarios is to capture the uncertainty which necessarily exists about the future development of the electricity market, and to ensure that the project which passes the regulatory test is robust to different assumptions about the future development of the market. NERA is of the view that MTC's approach to considering a single market development scenario in deriving the RAV is inadequate and does not represent a proper application of the regulatory test.

Discount rate

ESIPC, EUAA, NERA, TransGrid and ElectraNet question the use of a single discount rate, and note that MTC has used a commercial discount rate of 9.25%, which is significantly lower than that used in other recent applications of the regulatory test (11%), and therefore likely to increase the RAV and transmission charges. ElectraNet notes that while there has been a downward trend in interest rates since this work was undertaken, ElectraNet is of the view that interest rates have not reduced by 1.75% in this time, and the 9.25% proposed by MTP is lower than the rates that would be required by a commercial entity investing in unregulated electricity infrastructure.

NERA notes that 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, TEUS' choice of the discount rate will have a direct impact on the RAV derived for Murraylink.

Augmentation work

EUAA, TransGrid and NERA note that the calculation of gross market benefits includes around $9 million in additional investments not yet committed to, whereas this appears not to have been included in the regulatory test analysis.

NERA states that for the value of these investments to be incorporated into the analysis, Murraylink would first need to commit to funding them. If the investment is expected in the current year, then it could be included as part of the RAV derived for Murraylink. However, if the expected timing is after 2003, then the investment should be included as future capex, in deriving Murraylink's revenue requirement for the proposed regulatory period, rather than being included in the RAV. In this case, TEUS' assessment of the gross benefit of Murraylink would also need to be re-calculated, as any delay in the timing of the additional investment also implies a delay in the time at which the some of the market benefits arising from Murraylink arise.

NERA also notes that in the absence of a commitment by Murraylink to fund the additional investment, then the assessment of the gross benefit of Murraylink would need to be re-calculated, on the assumption that the investment was not in place. This would reduce the expected gross benefit, and therefore the RAV derived for Murraylink. The additional investments, if they had a proponent in future, could then be assessed at that time in the standard way, via an *ex ante* application of the regulatory test.

Reliability Benefits

ESIPC notes that MTC has used a different modelling approach for the calculation of reliability benefits compared to the approach used in assessing SNI and SNOVIC 400. ESIPC notes that Murraylink's assessment is based on assumptions of SRMC bidding behaviour and market driven new entry in combination with a quite separate and unproven modelling approach (in the NEM context) to forecasting unserved energy, resulting in the inclusion of the very high level of 'other reliability benefits'. ESIPC contends that there has been no consideration of alternative bidding scenarios or reliability driven (least cost) new entry, which we understand are required by the Regulatory Test.

NERA notes that MTC has calculated the reliability benefit by assessing how much market-driven generation is expected under both the 'with Murraylink' and 'without Murraylink' scenario, and then calculating the extent of the unserved energy which remains (using a probabilistic modelling tool) and valuing this unserved energy at VOLL (i.e., $10,000/MWh).

NERA indicates that the approach adopted by Murraylink differs significantly from the approach which was adopted by the IRPC in its evaluation of SNI and SNOVIC 400. The IRPC explicitly considered the reserve levels established by the Reliability

Panel for each region in the NEM, and then compared the expected market generation with these required reserve levels. Where there was a shortfall, reliability generation was then added to the market development scenario, such that the reserve criterion was met. The reliability benefit associated with each alternative project in the SNI and SNOVIC 400 analyses was then calculated on the basis of the extent to which each alternative defers the need for this reliability generation. As such, the calculation of the reliability benefit was conducted on a similar basis to the calculation of the benefit from the deferral of market generation.

NERA therefore recommends that, at the very least, the materiality of the difference in the approach is established by also valuing the reliability benefit associated with Murraylink on the basis of the value of the deferral of reliability generation (i.e., on a consistent basis to the previous IRPC analysis).

ElectraNet is concerned that there is a potential to double count the reliability benefits and the benefit associated with deferred market entry when calculating the gross market benefits attributed to Murraylink. ElectraNet notes that it would seem that either one or the other benefit is appropriate, but not both.

NERA notes that the TEUS assessment only assumed generator SRMC bidding, but that TEUS has correctly noted that benefits assuming another bidding scenario will be greater. However, NERA states this greater benefit would apply to all of the alternatives considered, but whether the *net impact* on the RAV calculated for Murraylink would be to increase the RAV if non-SRMC bidding scenarios were considered is not certain. NERA recommends that the modelling analysis explicitly considers the impact on the RAV of non-SRMC bidding assumptions.

VENCorp submits that MTP's analysis of market benefits should also include consideration of the relative economics benefit of Murraylink alongside a "least cost market development" sequence. The generation developments assumed under the "least cost market development" scenario would be the least-cost sequence of new generation required to ensure maintenance of the Reliability Panel's maximum unserved energy criteria. That is, additional alternatives should be assessed which result in the level of unserved energy in the NEM equivalent to the maximum level of unserved energy set by the Reliability Panel.

2.2.5 Commission's considerations

Does Economic value equal Gross market Benefits?

A number of submissions by interested parties have raised the issue of whether gross market benefits derived from the regulatory test should be used to determine the regulatory asset value of MTP.

The DRP proposes the use of an ODRC methodology for valuing and revaluing regulated assets together with the ability to write-down assets to below the ODRC value where this exceeds its economic value. Furthermore, in the authorisation of the Network Pricing and Market Network Service Providers code changes, the Commission stated that it would apply an ODRC valuation for conversion applications, and that the NSP would be required to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test. The regulatory test is consistent with the valuation of assets outlined in chapter 6 of the code.

In its response to submissions by interested parties, MTC states that consistent with the Commission's guidance, it has adopted an optimised deprival value (ODV) methodology for deriving a regulatory value for the Murraylink asset. Under the ODV, the regulatory value of the asset would be defined as the lesser of the ODRC or the economic value of the asset. As such MTC notes that it has defined the economic value in a manner consistent with the estimation of market benefits under the Commission's regulatory test. MTC further notes that this definition of economic value creates consistency between the Commission's regulatory test and the valuation and ongoing re-valuation of regulated assets.

The question for the Commission is whether it is appropriate to equate the economic valuation of an asset with the gross market benefits that it brings to the NEM is appropriate.

The Commission notes that as stated in the DRP, the derivation of the economic value of an asset-and the use of the value as a regulatory value – can be problematic, given that the regulatory setting determines the value of an asset to its owner, not the benefits that such an asset provides to the NEM. On the other hand, the ODRC valuation of an asset is well-defined, at least in theory and has been applied in a number of settings for the valuation and revaluation of assets. The Commission is not convinced that defining the gross market benefits as the economic value of Murraylink is appropriate or consistent with the intent of the regulatory test. That is, a backward deduction application of the regulatory test to determine an economic value in which the NPV of opex is subtracted from the gross market benefit is not consistent with the intent of the regulatory test. The Commission therefore proposes to determine the regulatory asset value based on the lowest cost alternative, which is akin to an ODRC method.

The Commission notes that there is difficulty in providing a definitive market benefit value based on one sensitivity analysis to determine the economic value of the asset. The gross market benefits as calculated under the regulatory test are subject to variability depending on the sensitivity and market development scenarios applied and the assumptions to the input variables applied. The range of market benefits for Murraylink and the alternatives (under MTC's assumption) is highlighted by the additional sensitivity analysis provided to the Commission by MTC.

Sensitivity Analysis and Market development scenarios

A number of submissions noted the lack of market development scenarios and stress testing or sensitivity analysis using different assumptions and parameters considered by MTC. In response to a request by SEIL during its review of TEUS's market benefits review, MTC provided additional market development scenarios and sensitivities that are presented in the tables below.

Table 2.3 Sensitivity Analysis

Sensitivity Description	Gross Market Benefits Estimate $m
Demand – low growth	136
Reliability benefits- using NEMMCO's reserve trader role	172
Discount factor – 10.25%	198
Indexing-VoLL treated at $10,000 MWh in 2003 nominal	199
Riverland deferral – deferred 5 years	199
Generator bid at 200% of SRMC- modelled results 2012	202
Riverland Deferral - deferred 6 years	202
Riverland Deferral – deferred 7 years	204
Riverland deferral – Deferred 8 years	211
Riverland deferral – low cost of Riverland augmentation	211
Riverland deferral – 100% decrease in deferred Riverland opex	212
Riverland deferral – Deferred 9 years	213
Reliability benefits – using NEMMCO's reserve trader role till 2005	214
Base case – medium growth	214
Long run equilibrium – year model results are assumed to represent long run equilibrium - 2012	214
Discount factor – 9.25%	214
10% increase in merchant O&M costs	215
Riverland deferral – Deferred 11 years	216
Riverland deferral – 100% increase in deferred Riverland opex	216
Riverland deferral – Deferred 12 years	217
Riverland deferral – high cost of Riverland augmentation	217
Long run equilibrium – year model results are assumed to represent long run equilibrium - 2018	218
Generator bid at 200% of SRMC- modelled results 2018	226
Demand – high growth	226
Discount factor – 8.25%	234
Long run equilibrium – year model results are assumed to represent long run equilibrium – 2014	239
Long run equilibrium – year model results are assumed to represent long run equilibrium - 2016	244
Long run equilibrium – year model results are assumed to represent long run equilibrium – 2013	246
Long run equilibrium – year model results are assumed to represent long run equilibrium - 2017	262
Long run equilibrium – year model results are assumed to represent long run equilibrium - 2015	270

Table 2.4 Market Development Scenarios

Scenario description	Gross Market Benefits ($M)
200% SRMC – Last Yr Market Simulation 2017	182
Murraylink incremental to SnowVic Augmentation (in-service date 1/1/2005)	201
200% SRMC – Last Yr Market Simulation 2012	202
Base Case	214
200% SRMC – Last Yr Market Simulation 2016	219
200% SRMC – Last Yr Market Simulation 2013	219
200% SRMC – Last Yr Market Simulation 2015	220
Murraylink incremental to Basslink (in-service date 1/1/2005)	229
200% SRMC – Last Yr Market Simulation 2018	226
200% SRMC – Last Yr Market Simulation 2014	309

Both tables highlight the variability in the gross market benefits. MTC notes that where the market benefits are calculated for the purpose of applying ODV methodology, the output required by the analysis is a single number, not a range. MTC further notes that the sensitivities demonstrate that the TEUS base case calculation of Murraylink's market benefits is sound, robust and conservative.

However, the sensitivities provided do not confirm that the base case chosen to determine the regulatory asset value is robust but indicate that the single number chosen by MTC is subject to variability. As such, the Commission considers that based on MTC's determination of a regulatory asset base using the gross market benefits derived from the regulatory test, the regulatory asset base would vary according to the input assumption, sensitivities and market developments scenarios.

Further, it must be recognised that there are a number of key assumptions in the regulatory test which has a direct and material impact on the estimation of market benefits. This highlights that the estimation of market benefits is highly sensitive to the assumptions adopted.

Discount rate

A number of submissions questioned the use of a single discount rate, and that the discount rate used by MTC was significantly lower than that used in other recent applications of the regulatory test. SEIL also noted that the NPV of the market benefits critically depends on the discount rate adopted. The higher (lower) the discount rate applied, the lower (higher) the gross market benefits.

The Commission has previously noted with respect to the discount rate that:

> The net present value calculation should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector[12]

MTC indicated that it appears to be widely accepted that the discount rate should reflect the cost of capital associated with an investment in unregulated activities in the

[12] ACCC, *Regulatory Test for New Interconnectors and Network Augmentations*, 15 December 1999.

electricity supply industry, and no comments have been made on this view. The Commission agrees with MTC that 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 and it would appear that such values have been selected arbitrarily.

The Commission also agrees with NERA in that the discount rate has proved to be a relatively uncontroversial parameter in regulatory test assessments as it has been used to rank alternative projects under the regulatory test, with absolute values not being relevant. Furthermore, 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 controversial. In the case of MTC, the choice of discount rate has a direct impact on the regulatory asset value derived for Murraylink. While MTC proposes a definitive value for the purpose of its methodology, such an approach is inconsistent with the way the regulatory test is applied. As noted previously, the sensitivity analysis has the purpose of ranking alternatives rather then determining one value.

Gross market benefits of alternatives

A number of submissions raised concerns with respect to the assumption that the gross market benefits of the alternative project are equivalent to that of Murraylink. The Commission notes that 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. As such MTC notes that a reasonable assumption it has made is that the market benefits associated with alternative projects are similar, and thus are unlikely to have a significant effect on the valuation determined. MTC indicates that the difficulty with quantifying the market benefits associated with different options provide a good rationale for being careful to have regard to only projects that have similar functions when undertaking an ODRC valuation.

MTC also notes 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 effect the ODRC valuation – and so a change to the ODRC valuation would only affect the ODV of an asset in circumstances where the economic value constraint is not binding. MTC also notes that the operative constraint on the ODV for the Murraylink asset is the economic value, rather than its estimated ODRC value. Accordingly, any change to the ODRC value on account of providing a different level of service would only affect the ODV to the extent that it was sufficient to change the relativity between economic value and the ODRC value.

The Commission agrees with interested parties that the benefits of alternatives to Murraylink need not come from the same source, and that each alternative has different technical characteristics, and thus is likely to provide different levels of benefits. However, the Commission notes that MTC has assumed and configured the alternatives so that each provides the same technical service and thus has the same technical characteristics.

While the Commission is of the view that care must be taken not to use the apparent size and benefits provided by the proposed augmentation as the basis for comparing it to alternative augmentations, and that the gross market benefits of the alternatives are considered. However, the Commission notes that the market benefits of the alternatives are unlikely to significantly differ from the market benefits of Murraylink. The Commission notes that in the SNI figures for SRMC, the medium growth, 9% discount rate case provides a market benefit of $219 million, which is in line, in gross terms, with Murraylink and its alternative gross market benefits.[13]

However, under the assumption adopted by MTC, a reconfiguration in the alternatives could possibly reduce their market benefits, and the benefits of Murraylink depending on which project is the least cost option.

Reliability Benefits

The Commission notes that a number of submissions have observed that the method TEUS's method of calculating Murraylink's reliability benefits is different from the method adopted by the IRPC for SNI, that TEUS has not explicitly modelled reliability entry plant, and that the inclusion of reliability plant would provide a lower level of unserved energy. The Commission's consultant, SEIL also noted the difference in the modelling of the reliability benefits.

In response to submissions by interested parties, MTC notes that TEUS's method is fully consistent with the code. The TUES methodology presumes only that VoLL represents the appropriate value of USE, and that market forces will continue to determine future market entry. It indicates that even if NEMMCO's reserve trader function is extended to July 2005, there is less chance that it will be extended beyond that time given the extent to which the market has matured already.
MTC further notes that TEUS used the MARS reliability simulation model and added reliability entry to the base case merchant entry schedule in regions and years where USE exceeded 0.002%. The simulation was repeated, adding progressively more reliability entry plant, until all regions satisfied the criterion in all years.

The Commission notes that calculating the reliability benefits prior to July 2005 using the methodology that MTC has adopted is likely to overstate the reliability benefits estimated, as NEMMCO's reserve trader role could be extended until July 2005. That said, the Commission is of the view that it does not find that TEUS assumption adopted to be inappropriate and inconsistent with the code or the regulatory test if such a methodology is applied beyond 2005.

In response to NERA's recommendation that the materiality in the different approach to valuing reliability benefits be determined, the Commission requested that MTC provide the difference in methodology on the gross market benefits calculated. MTC advises that using the reliability entry plant/reserve trader methodology through to June 2005, and the TEUS unserved energy methodology for July 2005 through to 2042 indicates a reduction in Murraylink's gross market benefits of $158,000 to $214.075 million. If these figures are current, it would appear that there is not material

[13] The Commission notes that the comparison is intended to be indicative only and the Commission notes that SNI evaluation by ROAM Consulting included a range of results.

difference between the methodologies for determining reliability benefits. On the other hand, MTC has advised that if it adopted a methodology consistent with the IRPC's for SNI, the gross market benefits would be $172 million.

With respect to comments by interested parties that the TEUS methodology has the potential to double count deferred merchant entry benefits and reliability benefits, the Commission agrees with MTC that TEUS has endeavoured 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. MTC notes that this becomes the separate estimate of Murraylink's reliability benefits.

Indexing VoLL

The Commission notes that TEUS assumes that VoLL will increase with inflation. MTC notes that TEUS has not studied the alternative case where VoLL remains constrained at $10,000/MWh in nominal dollars, and therefore declines in real dollars. MTC notes that this slow decline in the value of VoLL would not significantly change the energy benefits, market entry, or amount of unserved energy, but it would cause approximately $15 million in the value of unserved energy. Ignoring any other secondary impacts, this results in gross market benefits of $199 million.

The Commission agrees with SEIL's view that there is little consistency in the way that inflation is accounted for by MTC in the application of market benefits to date, and diverges away from the setting of VoLL under the code. However, the Commission notes that in recent times VENCorp has applied VoLL for its transmission planning of close to $29 600/MWh based on market consultation. A number of submissions have noted that VoLL, as defined in the code, is a wholesale market price cap and does not necessarily reflect the real or true value of lost load to end user customers, which may vary from customer type and location. The Commission concurs with these submissions.

Riverland Deferral benefits

A number of submissions queried the manner in which TEUS determined Murraylink's Riverland deferral benefits.

The Commission notes that in ESIPC's Riverland Augmentation Final Technical Report in December 2007/08, ESIPC states that "Murraylink alone does not provide adequate security for the Riverland beyond 2007/2008". Furthermore in the 2002 SA Annual Planning Report (APR) published by ESIPC, demand forecasts for the Riverland region are lower than those used in the Riverland study to the extent that the total demand originally forecast to occur in 2007/08 is, according to the ESIPC's estimates, is unlikely to occur until 2008/09. The Commission's consultant, SEIL also notes, based on ESIPC's Riverland study, that under a scenario where the Murraylink interconnector is not in service, inadequate reactive power support would be provided from 2007/08 onwards.

MTC provided additional sensitivities and market development scenarios which are presented above. MTC provided sensitivities with respect to the timing of the Riverland deferral benefits and estimated the gross market benefits for the deferral of Riverland works from 8 years till 12 years. As such, MTC has not provided the gross market estimates for the deferral of the Riverland works consistent with ESIPC's timing estimates.

In light of ESIPC's comments it would appear that the Riverland deferral benefits estimated for Murraylink by TEUS are overstated as it appears that Murraylink does not provide adequate security for the Riverland beyond 2008. As such the Commission agrees with ESIPC that in taking into account this timing issue and the impact on the gross market benefits, the estimated Riverland deferral benefits for Murraylink are in the order of $10 million to $15 million. The Commission's modelling has confirmed this.

Additional augmentation work

MTC has calculated the gross market benefits with the inclusion of $8.97 million in additional investment which it has included in the regulatory asset base. However, MTC has not committed to the additional investment. In discussions with MTC, the Commission was informed that such augmentation works were likely to be completed beyond 2003.

The Commission agrees with NERA and TransGrid that as the expected timing of these investments is after 2003, the investment should be included as future capex in deriving MTC's revenue requirement for the proposed regulatory period, rather than being included in the regulatory asset value. Further, the deferral of these augmentations implies a delay in the time at which some of the market benefits are realised and/or a reduction in the expected gross market benefits. The Commission has requested that MTC provide a revised value of gross market benefit which realises that the augmentation works are deferred till 2004/05.

In response, MTC advised the Commission that it will make a decision to progress the network augmentations based upon the Commission's final decision including the quantum and rationale of Murraylink's regulatory asset value. July 2005. As such based on this timing, MTC notes that the gross market benefits will reduce from $214.24 million to $211.156 million (a fall in $3.08 million). Furthermore, MTC has informed that due to a minor MARS data error identified by SEIL, there would be a $151,000 increase in the gross market benefits.

Phase-shifting Transformers and market benefits

MTC engaged engineering firm Burns and Roe Worley (BRW) to select and cost alternative projects that were deemed to provide the same technical service and gross market benefits as Murraylink. MTC notes that the essential features of the AC alternative projects are phase shifting transformers for alternative 3, and phase shifting regulators for alternative 1. Submissions by interested parties have indicated that such phase-shifting additions are not required for an AC line. As such the Commission proposes to exclude such additions from their respect projects. Phase-shifting transformers are discussed further in the alternative projects section of this chapter.

The Commission notes that in MTC additional submission of 17 March 2003, BRW describes the technical benefits of phase-shifting regulators/transformers and their ability to ensure that the alternative projects can transfer power in the same manner as Murraylink. Furthermore, TEUS describes that the increased transfer capacity due to the phase shifting transformers/regulators contribute between $20 and $25 million to the market benefits of Murraylink and its alternatives. The Commission notes that as it proposes to exclude such additions from the alternatives, it is likely that the gross market benefits for Murraylink and its alternatives would be reduced by between $20 and $25 million.

Preliminary View

The Commission accepts that Murraylink is likely to deliver gross market benefits ranging from $136 million to $300 million under most credible scenarios, with the median being around $190 million.

2.3 Alternative projects

2.3.1 Introduction

A regulatory test assessment requires an augmentation to maximise the net present value of the *market benefit* having regard to a number of alternative projects. This chapter compares the costs of alternative projects with Murraylink. This will facilitate the Commission's decision making process for two reasons. The first is that the Commission must determine whether Murraylink will deliver net benefits to the market, that is gross market benefits less the lifecycle operating costs. The second is that the lowest cost option will ultimately be used as the regulatory asset value for setting MTC's MAR.

2.3.2 MTC's application

BRW identified and assessed six possible alternatives to Murraylink which provided the exact same level of technical service as Murraylink : [14]

1. Buronga to Monash 275 kV AC mostly overhead transmission line, initially operating at 220 kV, with substation augmentations at Buronga and Monash.

2. Red Cliffs to Monash 140 kV DC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash.

3. Red Cliffs to Monash 220 kV AC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash.

4. Robertstown to Monash 275 kV AC overhead transmission line. Heywood to South East substation 275 kV AC overhead transmission line, with substation augmentations at Robertstown , Monash, Heywood and South East substation, and series capacitors at Tailem Bend.

5. Generation in South Australia and the Riverland and

6. Demand side management.

MTC indicates that BRW examined alternatives 5 and 6 for completeness and represented possible options for meeting the Riverland Load requirements, however they were deemed not equivalent to Murraylink.

MTC notes with respect to other alternatives, that a detailed base case was developed for the capital and the operations and maintenance costs of the assets, the base estimates were further subjected to a quantitative analysis of the cost risks so as to determine an appropriate contingency for each alternative. The contingency plus base estimates was used as the capital cost base for the project alternative and a net present cost of annual operations and maintenance over a 40-year period was added to develop a total cost for each of the alternative projects.

[14] KBR provided advice in relation to the environmental costs and constraints that would confront a developer of any of the alternatives projects to assist BRW to determine the likely impact of these costs and constraints upon the projects' costs.

Of this selection, BRW estimated that Alternative 3 was the lowest cost alternative with a total regulatory cost of $240.4 million, inclusive of lifecycle operations and maintenance costs.

Undergrounding

MTC states that undergrounding enables the Murraylink cable to be secure and reliable, and not susceptible to lightning, accidental vehicle damage or vandalism. MTC advises that the Murraylink route is situated along existing road reserves, and did not require new rights-of-way, easements or resumptions involving private land holdings. It says that this enabled Murraylink to be constructed without land-use impact, no visual impact, no ground current and minimal electromagnetic fields. MTC states that as a consequence, the environmental and community impacts of Murraylink are far less than those which would have resulted from the construction of a conventional overhead transmission line, (either HVAC or HVDC).

MTC also advises that the undergrounding of Murraylink provides a number of features which enabled the timely construction, environmental permitting, and cooperation with local citizens groups. MTC's application lists a number of features which it says assisted Murraylink's development and enabled it to be constructed in a relatively short period of time.

MTC's application lists the environmental awards that MTC has received based on the minimisation of environmental impact arising from the construction of Murraylink.

MTC engaged an environmental consultant, Kellogg Brown and Root Pty Ltd (KBR), to examine the four transmission line alternatives that were proposed by MTC. KBR states that its terms of reference included an assessment of potential undergrounding requirements to address environmental and social issues, and to achieve the required statutory approvals from relevant jurisdictions.[15]

KBR's letter to Burns and Roe Worley, dated 16 October 2002, states:

> "Other than a requirement for undergrounding of electrical services in subdivisions, there are no statutory, regulatory or policy positions, that we are aware of, for the undergrounding of high voltage transmission lines as a standard requirement. As such, it is very difficult to determine the extent of undergrounding, if any, that would be required for any of the alternatives proposed to achieve environmental and planning approvals.
>
> It is our view that in the current political climate, the government agency or Ministerial decision makers would balance the decision on environmental management objectives and requirements against the cost and commercial feasibility of undergrounding the transmission line. That is, if the environmental management objective is strongly held, then decision makers are likely to determine either that some undergrounding should be undertaken, or that the transmission line route should be altered to protect the environmental values identified. It is highly unlikely that they would require undergrounding of the entire transmission line to address environmental and social issues as proponents would probably argue that this would adversely affect project feasibility for little environmental and social gain."

[15] Letter from KBR to Burns and Roe Worley Pty Ltd, 16 October 2002.

As KBR notes in the same letter, a Joint Advisory Panel (Panel) appointed by the Commonwealth, Victorian and Tasmanian state governments, reviewed the environmental implications of the proposed Basslink interconnector. The Panel determined that as a general principle, the use of overhead transmission lines is acceptable, subject to environmental analysis. KBR also states that the Panel also identified a number of principles to provide guidance for situations where the use of overhead transmission lines might be inappropriate:

- Instances where the proposed transmission line passes too close to residences to breach the accepted buffer values relating to EMFs;
- The existence of highly valued heritage attributes, where an overhead transmission line could detract from the character of the attribute;
- A conflict between the transmission line and existing infrastructure or operations;
- Impacts upon flora and fauna in areas recognised for natural values under State and Commonwealth statute or policies.

Based on these principles, the panel recommended that the route of Basslink should be changed to lower the impact on high value conservation areas, and recommended the undergrounding of the cable on the coastal plain.

KBR provides examples of undergrounded transmission lines where proponents have altered their proposals to minimise potential environmental or community conflicts. These include the transmission line proposed by the State Electricity Commission of Western Australia (SEC), to connect the Beenyup Mineral Sands Mine to the Manjimup substation. In that case, the Western Australian Environment Protection Authority accepted the SEC's proposal on the proviso that the parts of the transmission line that passed through a high value forest were undergrounded.

KBR also notes transmission projects that have been voluntarily undergrounded. One is the Brunswick to Richmond (Victoria) transmission line, which was voluntarily undergrounded to minimise potential environmental or community conflicts, despite having been approved as an overhead line. KBR likens Murraylink to this project.

KBR's advice concerning MTC's proposed alternatives is categorised according to the lowest, most likely and potentially highest requirements for undergrounding transmission lines in specific areas (in terms of kilometres). The costs of undergrounding in the alternative projects were estimated subject to the expected costs that a developer might face to meet environmental restrictions on the project, such as re-routing lines to avoid environmentally sensitive areas, and tactical undergrounding where re-routing is not possible.

- **Alternative 1**: 30 km is categorised as 'most likely' needing to be undergrounded, based on a need for tactical undergrounding past the Ramsar wetland within the Bookmark Biosphere reserve in South Australia. Ramsar wetlands, migratory species of birds, and nationally threatened species and ecological communities are all matters of national environmental significance under the *Environment Protection and Biodiversity Conservation Act 1999* (EPBC Act). According to KBR, these environmental values would provide sufficient impetus for decision makers to consider tactical undergrounding to achieve environmental management objectives, despite increased cost.

60 km of Alternative 1 is categorised as highly likely. 60 km is estimated as the distance required to cross the Bookmark Biosphere reserve. KBR advised BRW that this outcome could eventuate if the decision making governments take a holistic view of the environmental and social values of the area.

- **Alternatives 2 and 3:**

  KBR states that 25 km of alternatives 2 and 3 are "Most Likely" to require undergrounding. This is based on these projects crossing the settlements at Red Cliffs (outskirts of Mildura, Victoria) and Lyrup in South Australia. KBR states that undergrounding in these areas would minimise social and environmental impacts, and community opposition to the proposal.

  40 km of undergrounding is considered by KBR to be "Highly Likely". This is based on these projects crossing the settlements at Red Cliffs and Lyrup, and the Sunset National Park (Victoria). KBR advises that re-routing the transmission line so that it does not cross the national park is not possible given the size and location of the park. KBR states that as a consequence, the only mitigation option would be to underground the transmission line where it passes through the national park.

2.3.3 SEIL Review

With respect to the alternative projects, the Commission engaged SEIL to consider:

- the methodology, assumptions and findings of TransEnergie US Ltd (TEUS) in their assessment of the market benefits associated with Murraylink;
- the appropriateness of the alternative projects selected by Burns and Roe Worley (BRW), and the costs associated with those alternatives; and
- the appropriateness of the opening asset valuation, in line with the regulatory test.

SEIL was not engaged to assess whether all the technical services provided by Murraylink are necessary or economic and proceeded on the basis that the alternatives would be compared with Murraylink's current transfer capability.

Selection of alternative projects

SEIL agrees with BRW's conclusion that generation and demand side management options should not be considered as alternative projects for the purposes of calculating a ODRC. Generation and demand side management options are considered in the calculation of the market benefits. The alternative generation options are the merchant entry generators that enter the market in the "without" Murraylink cases; and the demand side management options are the voluntary load reduction options that enter the market as in those cases.

SEIL found that alternatives 1, 2 and 3 provide technical services that are the same as, or sufficiently close to, those provided by Murraylink to consider them possible alternatives. On the other hand, the technical services provided by Alternative 4 are significantly different to those provided by Murraylink. The market benefits are also significantly different in that Alternative 4 provides no benefit to the Snowy/NSW or Snowy/Victoria interconnections and does not provide a direct linkage between the South Australian and NSW market regions. Therefore, Alternative 4 does not provide a sufficiently similar level of service as Murraylink to be considered an alternative to Murraylink for purposes of determining a ODRC for Murraylink.

SEIL noted that in order to obtain cost estimates that are directly comparable with the investment in Murraylink, the costs of the alternative projects are estimated subject to the conditions that they are:

- stand-alone projects being built by a new entrant. This means that, compared with projects being built by existing TNSPs, the new project carries the full costs of infrastructure support, administration and spares that could otherwise be spread over a number of projects. It also means that the costs of all spares are included in the capital cost estimates of the new project.
- real projects, so include all the costs that a developer would provide for, including:
  i. a budgeted contingency to cover uncertainty in the cost estimates; and
  ii. expected costs of mitigating environmental impacts. These include the costs which a developer might face to meet environmental restrictions on the project, such as re-routing lines to avoid environmentally sensitive areas and, where this is not possible, tactical undergrounding.

Cost of undergrounding

SEIL notes that the underground cable costs are a significant portion of the total base cost estimates for each alterative project, and particularly of the total transmission line costs:

- for Alternative 1, $60 million out of a total line cost of $88 million;
- for Alternative 2, $33 million out of a total line cost of $53 million; and
- for Alternative 3, $50 million out of a total line cost of just under $75 million.

SEIL also notes that these costs were obtained from one supplier, and that BRW had no internal estimates of underground costs to use as a benchmark. In the absence of a benchmark, BRW used the supplier's estimates as a base estimate in the quantitative risk assessment, and applied a cost material variation of -20% / +10% and installation cost variation of -25% / +15%.

SEIL states that it was unable to verify the accuracy of the cost estimates, but that the high proportion of the total costs highlights the dependence of the base cost estimates on KBR's recommendations regarding the necessity of undergrounding. As a result, it contends that stronger justification should be provided for both the need for, and cost of, underground cables for the alternative projects, and that the cost of the alternative projects crucially hinges on KBR's report, which recommends a "most likely" amount of undergrounding, as noted above.

SEIL illustrates the effect of the assumptions on the degree of undergrounding on the base cost estimates of the alternatives in the table below.

Table 3.1 Costs of undergrounding

Alternative (Base) Costs with and without undergrounding						
	Alternative 1		**Alternative 2**		**Alternative 3**	
	With	Without	With	Without	With	Without
Development costs	15,769		13,169		13,569	
Transmission line costs	88,095	35,793	53,029	25,146	74,647	31,482
Switchyard costs	78,588		81,186		58,572	
Total EPC project cost	166,683	114,561	134,215	106,332	133,219	90,054
Profit & overheads (10%)	16,668	11,456	13,422	10,633	13,322	9,005
Interest during construction	36,373	26,628	29,374	24,440	29,274	21,152
TOTAL	235,493	168,415	190,180	157,174	189,384	135,981
Difference		**-68,102**		**-36,432**		**-56,399**

Table 3.1 involves the following assumptions (made by SEIL):

1. The development costs remain unchanged. However, it believes that it is likely that the costs of obtaining planning and environmental approvals would be significantly higher without undergrounding.
2. The transmission line costs have been reduced by removing the underground cables and replacing them with overhead lines of the same unit (per km) cost as the other overhead lines in the project. SEIL advises that reducing the transmission line costs results in corresponding reductions in profit and overheads (10% of the total transmission line and switchyard costs) and interest during construction.

Contingency and treatment of risk

SEIL notes that BRW has added an allowance for contingency which has been added to base cost estimates. A contingency was calculated for each of the alternative projects using @Risk in Excel, a spreadsheet model utilised to assess the probability of the base cost estimate being too low or too high. BRW recommends that the P75 cost be used as the replacement cost of the alternative projects. SEIL considers that the P75 cost estimate is an overly conservative basis for valuation. While the general approach taken by BRW has merit, SEIL believes that the P50 cost is more in keeping with the ORC methodology which is aimed at setting a typical cost for particular categories of assets.

2.2.4 Submissions from interested parties

Selection of alternative projects

TransGrid, ElectraNet, ESIPC, the NSW Government and VENCorp contend that alternative projects selected should not be based on their technical equivalence to Murraylink. ElectraNet considers that the alternatives put forward by MTC and their costs are inappropriate. In particular, ElectraNet argues that plant and equipment such as Static Var Compensators, phase shifting transformers and underground cable is either not required or justifiable under the NEC; or does not represent the optimum means of providing the associated service. VENCorp and TransGrid also support the position that phase shifting transformers are not required in an AC network but would be required by an MNSP.

ElectraNet, ESIPC, TransGrid, and the NSW Government contend that SNI should also be considered as an alternative project to Murraylink.

TransGrid suggests that the Commission consider a number of other alternative projects including:

- Heywood A + Robertstown to Monash line at a cost of $100 million
- Horsham A + Robertstown to Monash line at a cost of $160 million and
- NEWVIC 2500 + Robertstown to Monash line at a cost of $200 million.

Powerlink contends that MTC's proposed spares will set a new benchmark level for other TNSPs which will be incorporated into subsequent regulatory resets.

The Mildura Rural City Council (Mildura Council), the Wentworth Shire Council, and the Australian Landscape Trust support the undergrounding of Murraylink and its alternative projects. The Mildura Council states that a large portion of Murraylink is installed in its municipality, including the converter station installed at Red Cliffs, approximately 15 km south of Mildura. The Mildura Council states that it supports MTC's position that any proposed transmission line developed generally from Mildura west to the South Australian border would require significant (or at least strategic) portions of the line to be undergrounded to gain development approval from the Council. The Mildura Council also states that it is likely that it would not approve transmission proposals in the Murray Sunset National Park region, and the region surrounding Red Cliffs west to the Calder Highway, unless the line was undergrounded in those two areas as a minimum. The Commission also received several submissions from private landowners in Queensland who support the undergrounding of transmission lines in most circumstances.

ESIPC, TransGrid and NRG Flinders note SEIL comments that the costs of the alternative projects are heavily influenced by the level of undergrounding assumed, and that more justification for undergrounding is necessary.

Powerlink presumes that if the Commission accepts that tactical undergrounding represents the lowest cost alternative for a transmission line in a remote rural area, then Powerlink could extrapolate a higher degree of tactical undergrounding for less remote and more urbanised environments for its own network. Powerlink contends that the Commission's acceptance of MTC's valuations of tactical undergrounding would set a number of precedents:

- a new benchmark for the definition of a Modern Equivalent Asset (MEA) and their value, for new transmission lines. Powerlink argues that in turn, this must flow on to the determination of replacement asset value for transmission lines.
- given the significant amount of new line projects arising in the next few years, the inclusion of tactical undergrounding would be so material as to trigger a mid-term revision of Powerlink's revenue caps.
- a Commission decision in favour of tactical undergrounding would change Powerlink's approach to active line projects, which are currently based on overhead lines only. Powerlink states that a number of these projects have generated actual (rather than possible) community agitation for undergrounding.

ElectraNet submits that Murraylink's custom-made underground cables (buried to greater than normal depth), implies over-design and sub-optimal augmentation of the network. It states that in examining Murraylink's net market benefits, the use of specialised underground cable and technology must be questioned, and if found to be inappropriate, should be optimised down to the least-cost technically acceptable alternative.

2.2.5 Commission's considerations

Selection of alternative projects

The Commission concurs with the views of interested parties that an assessment under the regulatory test does not require an assessment of alternative projects that provide the "exact same level of technical service". Similarly, for an assessment of an existing interconnector under the regulatory test for the purposes of a conversion application the Commission does not believe it is appropriate for alternative projects to have the "exact same level of technical service". The Commission feels it is more appropriate that it be guided by what delivers the highest net benefits to the market.

Therefore, the analysis conducted by the Commission considers what the NEM would have delivered at a specific point in time if a regulatory test assessment was conducted. Among the questions considered by the Commission were what level of undergrounding would have been appropriate and what level of controllability is desirable for the NEM.

Generally, the Commission believes that the range of projects specified by BRW is appropriate. While other alternatives were proposed in a number of submissions the Commission's analysis of these alternatives indicates that their costs were typically higher than those of MTC's proposed alternatives after the Commission's adjustments which are discussed below. Further, a number of parties argued that SNI should be considered an alternative project by the Commission. The Commission believes that the essential elements of SNI are captured in alternative 1.

Undergrounding

The Commission notes SEIL's comments regarding the New Zealand ODV Handbook, with respect to undergrounding. Essentially, the Handbook states that an underground cable will be valued at the cost of an overhead line, unless there is specific evidence that a local authority could not grant consent for overhead transmission lines, or a legal obligation for underground cables exists. In this context, MTC has provided the Commission with evidence of planning and environmental deliberations and approvals for other transmission lines and wind farms, although none for Murraylink itself.

The Commission considers that although similar rules to the ODV Handbook do not exist in Australia, these are reasonable considerations for the valuation of underground transmission assets. As the economic regulator of transmission network services in the NEM, the Commission is not in a position to make a judgement on where and when transmission lines should be undergrounded. Therefore, it is appropriate for the Commission to be guided only by the legal requirements that are relevant each particular case.

Further, the Commission recognises the growing concern about the construction of above ground high voltage transmission lines. The Commission has received a number of submissions from QLD residents who oppose the construction of above ground transmission lines. The Commission does not believe that sufficient evidence has been provided by MTC to support its proposed tactical undergrounding of Alternatives 2 and 3. The reasons for this are set out below.

MTC argues that tactical undergrounding is justified in the costing of the alternatives because it minimises potential difficulties in obtaining environmental approval, and opposition from local communities. In this context, the Commission notes the examples provided by KBR of transmission projects that have been voluntarily undergrounded in response to environmental and community concerns. KBR points to the Brunswick to Richmond transmission line as an example of a project that was voluntarily undergrounded to minimise potential environmental or community conflicts, despite having been approved as an overhead line. KBR's advice to MTC was that Murraylink could be included in this category. Conversely, Powerlink takes the view that where no specific environmental laws require it to underground its transmission lines, substantial community resistance shall not impede its plans either.[16]

Clearly, the proponents of transmission in the NEM have very dissimilar views on the degree that social and environmental issues should affect the development of a transmission line. MTC perceived that potential (not actual) opposition to overhead transmission lines from environment agencies and local communities provides sufficient imperative to develop Murraylink as an underground cable.

[16] Powerlink pursued its plans to build overhead transmission lines through a farming area to the extent that it successfully defended an attempted injunction in court.

Such diverse perceptions highlight the importance that the Commission have regard only to the legal requirements for the siting of transmission cables. To this end, the Commission has received advice from SA Planning that an overhead transmission line through the Bookmark Biosphere and Ramsar regions, similar to the route taken by Alternative 1, would be questionable from an environmental perspective. In light of this information, the Commission is satisfied that approximately 30 km of undergrounding through the Bookmark Biosphere would be likely to be necessary in order for it to obtain environmental approval.

Planning SA provided advice on the need for undergrounding through Lyrup. Unlike the Ramsar wetlands section of the Biosphere that falls within Commonwealth jurisdiction, the Lyrup region is administered by Planning SA.[17] Alternatives 2 and 3 both pass through this area. Planning SA has advised the Commission that following an environmental analysis of a transmission line crossing the Murray River at Lyrup, undergrounding would be a preference, but not a specific requirement. Furthermore, Planning SA states that any transmission line alignment between Red Cliffs and Monash may not require undergrounding, but that the undergrounding of river crossings for Murraylink was part of MTC's development application, and not a requirement of any approval.

Therefore, the Commission is not satisfied that sufficient evidence exists to support the undergrounding of Murraylink and its proposed alternatives at this stage. Although Murraylink and alternatives 2 and 3 traverse populated areas and farming communities, the Commission is of the view that there is not similar impetus for these transmission lines to be undergrounded as in the Brunswick to Richmond case, which is located in a densely populated area of metropolitan Melbourne.[18]

Furthermore, the undergrounding of that line occurred after several years of intense community opposition to the original proposal. While the Commission acknowledges that this is the type of opposition that MTC has referred to, specific information provided to the Commission from the relevant government departments indicates that MTC's views regarding environmental and community opposition to an overhead transmission line may not be exact.

Based on advice from SA Planning, the Commission has formed the following views:

- an overhead transmission line through the Bookmark Biosphere and Ramsar regions, similar to the route taken by Alternative 1, would be questionable from an environmental perspective

[17] Refer to Appendix B.

[18] The Brunswick to Richmond line was a project undertaken by the former SECV. At that point in time, transmission projects were not subject to a regulatory test, nor were the planning stages contestable, as they are now in Victoria. Therefore, the pressure for a transmission project to be developed on the basis that it maximised that net present value of market benefits compared to feasible alternatives did not exist as it does now. That is, it is questionable whether there was the same pressure for transmission projects to be efficient under the former government-owned vertically-integrated regime for electricity supply, as there is now in a national dis-integrated market.

- although Murraylink and Alternatives 2 and 3 traverse populated areas and farming communities, there is not a similar imperative for these transmission lines to be undergrounded as in densely populated areas.

Therefore, the Commission concurs with Murraylink's proposed undergrounding for alternative 1, but at this stage does not believe that undergrounding would be required for alternatives 2 and 3.

Phase shifting transformers and static var compensators

Most interested parties argue that phase shifting transformers and static var compensators are only required where controllability is desirable and that these costs were included by MTC to ensure that the alternatives provided the same level of service as Murraylink, thereby inflating the cost of the alternative projects. This raises the broader issue of whether a controllable line is desirable from a NEM wide perspective over an uncontrollable line.

From a system planning viewpoint, the NEM has traditionally been built using AC technology. This was largely a reflection of the relative costs of the technology, which has gradually become less over time. Losses on an AC line are also typically higher than losses on a DC line which has also influenced the decision making process of network planners.

The Commission acknowledges that there are number of advantages from a controllable line, particularly when there is more than one interconnector between two regions. In the context of the NEM, the flows on AC line between Red Cliffs and Monash would be dependent on the flows along Heywood. This is not the case for a DC line which could still operate, at a reduce level, even if Heywood was down rated, for example due to lightening strikes.

However, as was noted in Section 1, the construction of Murraylink was primarily guided by the requirements of the Safe Harbour Provisions. Therefore, it was developed first and foremost as a market network services according to the Safe Harbour Provisions, not in accordance with the chapter 5 provisions of the code. As has also been stated, the Commission is seeking a consistent approach between its considerations of MTC's application for conversion and its approval of other forms of regulated investments. Therefore, the Commission concurs with the views of interested parties that controllability, while providing a number of benefits, is not necessary for regulated interconnectors in the NEM. The Commission has, therefore, adjusted the cost of the alternatives to reflect the reductions in the phase shifting transformers and their associated spares.

Regarding the static var compensator the Commission concurs with the views expressed by BRW in its letter of 2 April 2003 which state that beyond the issue of what provides the exact same level of service as Murraylink, there is a need for fast acting voltage control around Red Cliffs and Monash.

Contingency

The Commission concurs with the findings of SEIL regarding MTC's proposed contingency allowance. While MTC's general approach is supported by industry and the Commission, the magnitude has been questioned. While analysis by MTC's consultant Worley suggests that a contingency based on P50 is inappropriate because the specific projects outlined do not form part of a portfolio of projects, the Commission does not believe that an efficient costing of the contingency component would be based on anything other than a P50 analysis. The Commission has therefore based its contingency allowance on a P50 analysis.

Other amendments

Other adjustments made by the Commission to the cost of the alternative projects include reductions in the interest during construction and profits and overheads because of the reduced capital costs. The Commission has also based the opex costs on 1.5% of the capital costs based on advice from BRW and the Commission's consultant PB Associates.

The Commission's adjustments are outlined in Table 3.2.

Table 3.2 Regulatory cost of alternative projects

	Alternative 1	Alternative 2	Alternative 3	Alternative 4
MTC's proposed capital costs	$235.49	$190.18	$189.38	$194.90
less undergrounding	$0	$36	$56	$0
less phase shifting transformers and spares	$19	$0	$19	$19
Add contingency based on P50 rather than P75	$4.92	$6.68	$6.91	$3.51
Less difference of interest during construction	$8.34	$3.93	$6.65	$7.43
Less difference of profit and overheads	$0.33	$0.00	$0.55	$0.40
Commission's calculated capital cost	**$212.66**	**$157.31**	**$114.42**	**$171.48**
Add lifecycle opex costs	$30.65	$22.93	$16.95	$24.91
Commission's calculated regulatory cost	**$243.31**	**$180.25**	**$131.37**	**$196.39**

As outlined in Table 3.2 the Commission's proposed amendments to the cost of the alternative projects suggests that Alternative 3, which is an overhead AC line between Red Cliffs and Monash, is the lowest cost alternative. This cost is less than the regulatory asset value proposed by MTC of $176 million.

A new interconnector or an augmentation option satisfies the regulatory test if it maximises the net present value of the market benefit having regard to a number of alternative projects, timings and market development scenarios. Based on the Commission's analysis, the interconnector which maximises the net market benefits is Alternative 3, which delivers net market benefits under most credible scenarios ranging from $5 million[19] in the lowest cost scenario to $269 million[20] under the realistic bidding scenario with average net market benefits close to $60 million in the median scenarios, even if the phase shifting transformers are deducted from Alternatives 1 and 3.

Therefore, based on the Commission's analysis, modified Alternative 3 is the option that satisfies the regulatory test. For the purposes of determining MTC's regulatory asset value and opex costs the Commission proposes to use Alternative 3 in determining MTC's MAR.

Preliminary View

The Commission's proposed amendments to the cost of the alternative projects suggests that Alternative 3, which is an overhead AC line between Red Cliffs and Monash, is the lowest cost alternative. As a result, Alternative 3 satisfies the regulatory test and ,therefore, for the purposes of determining MTC's regulatory asset value and opex costs the Commission proposes to use Alternative 3 in determining MTC's MAR

19 $136 million (gross market benefits) less $131 million (life cycle project cost)

20 $310 million less $131 million (life cycle project cost)

Section 3 – Maximum Allowed Revenue

3.1 The cost of capital

Clause 6.2.2(b)(2) of the code requires that the Commission seek to achieve a fair and reasonable rate of return on efficient investment as one of the objectives of economic regulation. Further guidance is provided in Clause 6.2.4(c)(3) of the code in which it is stated that the Commission must have regard to the WACC of the transmission network. In addition, the Commission is to have regard to the risk adjusted cash flow rate of return required by investors in commercial enterprises facing similar business risks to the transmission network.

Electricity transmission is a highly capital intensive industry where generally return on capital accounts for about two-thirds of the AR. Relatively small changes to the cost of capital could have a substantial impact on total revenue requirement and, ultimately, end user prices.

The importance of the return on equity is that, if it is too low, the regulated network will be unable to recover the efficient (and fair) costs of service provision and perhaps, more importantly, may not have adequate incentive to augment facilities when appropriate. Conversely, if the return on equity is too high, this will affect business-input cost and the ability of firms to compete domestically and overseas, as well as a significant impact on down stream investment and allocative efficiency.

3.1.1 Regulatory control period

MTC's proposal

In its application for conversion to a prescribed service and Maximum Allowed Revenue, MTC has proposed that the regulatory period should be of 10 years' duration. Therefore, MTC's revenue cap would effectively commence from the date of the Commission's final decision on the application, and expire in December 2012.

MTC states that a 10 year period is appropriate for the Murraylink interconnector due to the absence of capex, a forecast for "highly efficient" operating and maintenance activity for the next 10 years and beyond, and MTC's view that these factors provide a good deal of certainty for the regulatory period. MTC also contends that deferring the regulatory reset for 10 years instead of five would result in significant savings for the Commission, MTC participants, and MTC itself.

In addition, MTC argues that a regulatory period of 10 years provides certainty that encourages private sector investments and attracts new entrants to the NEM. Transmission investments are very long term investments for which investors seek as much certainty as is reasonably possible, especially for regulated investments where returns are designed to reflect lower levels of risk. MTC contends that upon appropriate conditions, such as those presented by MTC, the Commission's acceptance of an almost 10 year regulatory control period would provide a positive signal to investors that the Commission is willing to provide a good level of certainty where it can.

Finally MTC argues that given its asset depreciation profile, a regulatory control period over 10 years would enable the smoothing of MTC's revenue over a longer period and the avoidance of an abruption change on revenue after five years.

Submissions by interested parties

ElectraNet and the EUAA oppose a 10-year regulatory period on the basis of consistency with the Commission's previous revenue cap decisions for TNSPs. NRG Flinders notes that the Commission needs to consider whether MTC's request for a 10-year regulatory control period is appropriate given the regulatory periods of coordinating TNSPs have been based on a nominal 5-year period. NRG Flinders states that such an approach will set a precedent for inter-regional assets.

TransGrid supports a longer duration between regulatory resets for regulated transmission services, with scope for pass throughs and meaningful measures of service performance. However TransGrid, NRG Flinders, EUAA, and NERA note that a longer regulatory period would provide the Commission with no scope to re-optimise if future circumstances change and that it also exposes end-users to optimisation risks for twice the normal period. EUAA suggests that if the Commission allows MTC a 10-year regulatory control period, the Commission should consider re-opening the revenue determination if circumstances change.

Headberry Partners notes that the code requires that a regulatory control period must exceed 5 years and therefore the Commission is obliged to consider MTC's request. However, Headberry Partners also notes that the Commission must also consider the detriment associated with accepting a longer regulatory period will provide Murraylink with regulatory certainty over the period where SNI and possible other works come into operation.

MTC's response to comments by interested parties

In response to submission that the 10 year bond rate proposed by MTC is inconsistent with the Commission practice of using a 5 year bond rate, MTC notes that as it has proposed a 10 year regulatory control 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.

Commission's considerations

Section 6.2.4(b) of the code states that in applying the form of economic regulation specified in clause 6.2.4(a), the Commission is to set a revenue cap to apply to each TNSP and/or Transmission Network Owner for a period of no less than 5 years.

In section 9 of the DRP the Commission states that it will conduct reviews of the TNSP's revenue every five years. However it also states that the Commission will consider extending the regulatory review period when requested to do so by the TNSP. In its proposal the TNSP must justify extending the regulatory review period beyond five years, and demonstrate that any such change will not disadvantage users of network services and consumers. The Commission will then consider the merits of the application and address the issue of the length of the regulatory period as part of its revenue cap decision.

The DRP also states that in extending the regulatory period, one of the factors it would take into consideration is the expected size of future efficiency gains. MTC does not expect to realise any efficiency gains over the 10 year period. According to MTC, this reflects the static nature of the asset and it is not expected that the asset will be affected by exogenous influences such as technological change.

The Commission has on two previous occasions approved a regulatory control period of 10 years. The AGLP - Central West pipeline and the NT gas pipeline. In the Central West Pipeline a 10-year period was granted on the basis that it was a Greenfield project and that the price path was much less than the determined tariff order. The 10-year period was used to facilitate growth and expand the market. In the Commission's NT Gas decision, the assets pertaining to the NT gas project are leased. The lease expires in 2011 and it is expected that the gas basin will be depleted. In both the Central West and NT gas projects, the 10-year approach to determine the appropriate risk free rate and cost of debt was used.

In determining the appropriate length of the regulatory period the Commission notes that there is a trade off between providing sufficient time for the business to have an incentive to make efficiency gains, and ensuring that customers do not have to wait too long to benefit from those gains in the form of lower prices. Efficiency gains can generally be made in opex and/or capex.

The Commission agrees with TransGrid that the magnitude of the efficiency gains achieved over the period can be expected be low. The Commission notes that Murraylink is already built, and so there is appears to be little scope for future efficiency gains on its capital expenditure costs given that the Commission has adopted an opening asset value for Murraylink equivalent to alternative 3, which is below Murraylink's actual costs. Furthermore, Murraylink has proposed little capex over the regulatory period. In relation to opex, the Commission has provided an opex allowance based on Alternative 3, which is significantly below that requested by MTC. Therefore the Commission is of the view that given the fall in the opex allowance, there appears to limited scope for efficiency gains.

Furthermore, the regulatory asset base of MTP is the initial regulatory asset value of Murraylink, which is one interconnector, unlike other regulated TNSPs which operate as part of a regulated network. Therefore as there appears to be little scope for efficiency gains, there are advantages in deferring the regulatory reset for 10 years instead of 5 as it would result in regulatory cost savings and certainty for MTC.

On the basis of the information provided to the Commission at this point, the Commission is of the view that MTC's proposal for a 10-year regulatory period is justified. The Commission notes that the regulatory period provided to MTC is slightly below 10 years. The Commission has provided MTC with a half year revenue stream in 2013 to align MTC regulatory control period with the regulatory period of other TNSPs.

3.1.2 The capital asset pricing model

Clause 6.2.2 of the code requires that one of the key outcomes that the revenue regulatory regime administered by the Commission, must provide for a:

> a sustainable commercial revenue stream which includes a fair and reasonable rate of return to *Transmission Network Owners* and/or *Transmission Network Service Providers* (as appropriate) on efficient investment, given efficient operating and maintenance practices.

Schedule 6.1(2.2.2) of the code states that there are a variety of methods that can be applied to estimate this key return on equity (Re) component. For example, prices to earnings ratios, dividend growth model and arbitrage pricing theory. However, in practice the capital asset pricing model (CAPM) remains the most widely accepted by regulators.

The CAPM calculates the required return given the opportunity cost of investing in the market, the market's own volatility and the systematic risk of holding equity in the particular company. The CAPM determines the rate of return from the perspective of the investor measured in cash flow terms. This includes the returns from year to year as well as the value to the investor accruing as the result of any net appreciation in the capital base.

The CAPM formula is:

$$R_e = R_f + \beta_e (R_m - R_f)$$

where: R_f = the risk free rate of return — usually based on government bond rates of an appropriate tenure;

$(R_m\text{-}R_f)$ = the market risk premium (MRP) — the return of the market as a whole less the risk free rate; and

β_e = the relative systematic risk of the individual company's equity.

The CAPM expresses the rate of return as the post-tax nominal return on equity. This can be adjusted to allow for debt to derive the corresponding return on assets, otherwise known as the WACC.

Key parameters

The key parameters relevant to WACC/CAPM analysis are:

- the risk free interest rate (R_f);
- the expected rate of inflation (F);
- the cost of debt (R_d);
- the market risk premium (MRP);
- the likely utilisation of imputation credits (γ);
- the likely level of debt funding (D/V);

- the equity beta (β_e) of the company; and
- the statutory tax rate (T) from which effective tax rates on debt (T_d) and equity (T_e) can be derived for individual firms.

The Commission's assessments of each of these measures are discussed in turn.

3.1.3 Estimate of the risk free interest rate

The risk-free rate (rf) is an important parameter which is used to determine both the cost of debt and the cost of equity. The risk-free rate measures the return an investor would expect from an asset with zero volatility and zero default risk. This rate of return can be approximated by the yield on long-term government bonds, which are viewed as risk-free assets since the government can honour all interest and debt repayments.

In the CAPM framework all information for deriving the rate of return should, in principle, be as up-to-date as possible at the time the decision comes into effect. In the case of interest rates and inflation expectations, the financial markets set the parameters on a daily basis. Therefore it may be argued that there is little justification for using historical data.

On this issue, statement 6.7 of the DRP states:

> The risk free rate will be normally based on a 40 trading day moving average covering the eight weeks prior to the reset date unless there is evidence to suggest that the current rate of the day represents a transition to a new level which is expected to be maintained.

MTC's proposal

MTC proposes a ten-year bond rate of 5.4 per cent. Further, MTC commissioned a report by Professor RR Officer (Officer) that supported a ten-year bond rate and a shorter interest rate sample.

Officer argues that in the context of the CAPM theory there is no reason to pick one duration over another. However, ideally the duration of the CAPM should be the duration of the CAPM should be the duration of the planning period for which the CAPM is to be used to estimate an expected or required return. This means that if the planning horizon is a long-term investment then a long-term government bond is the most appropriate duration to use.

Furthermore, Officer argues that it has been conventional in Australia to use 10 year Commonwealth Bond Yields as the proxy of the risk free rate as it is a highly liquid security which provides a good reflection of the expected yield on a long term government security. To the extent that a shorter rate has been used in electricity it has only been by the Commission in relation to Snowy Mountains and Powerlink. Officer notes that another contentious issue is defining the point at which the redemption yield on a government security be used. Typically regulators have used an average running from 12 months down to 20 days. The argument is that these averages remove the spike, which may be reflected in the rates dur to some short-term uncertainty. Officer argues that there is no theoretical justification for using an average of rates. By taking an average of the last 20 days or longer simply lessons the information content in the last rate about expected future rates.

Submissions by interested parties

NERA indicates that MTC has proposed a 10-year bond rate rather than the Commission's practice of using the yield on a 5-year Commonwealth bond. NERA also notes that on 17 December 2002, the spread between the five and ten year bond rates was 0.34 per cent, if this is a indicative spread it would mean that the use of a five year bond rate would result in a reduced vanilla WACC for Murraylink of 8.64 per cent.

Commission's considerations

The Commission notes that redemption yields on government bonds vary depending on the term of the security, meaning that it is important to specify a term when estimating the risk-free rate. There exists significant debate, however, over the term that should be used in regulatory decisions. It has been suggested by some that it is appropriate to adopt a rate that is linked to the regulatory period, while others argue that the use of a longer-term rate represents an appropriate measure.

Industry parties have argued that a 10-year bond rate is most appropriate for the long lives and investment horizons of most assets. The Commission has previously noted that that regulation is designed to set a return for the regulatory period, and not for the entire life of a firm's individual assets. The Commission in both the Central West pipeline and NT gas pipeline decisions where it adopted a 10 year regulatory control period, the 10-year approach to determine the appropriate risk free rate and cost of debt was used. Therefore the Commission is of the view that as it has adopted a 10 year regulatory period for MTC, it would be appropriate to use a 10 year bond rate.

Using a 10-year Government bond instead of a five-year bond will increase the value of the risk free rate, and subsequently the equity beta. The cost of debt could also increase through a move from five year to 10-year bond rates as the debt margin is added to the risk free rate to determine the cost of debt.

The Commission adopted the forty trading day average in NSW and ACT, and Powerlink revenue cap decisions. However, the Commission used a 10-day moving average of bond rates in its recent SPI PowerNet and ElectraNet revenue cap decisions. The Commission remains of the view that it is appropriate to use a short-term average of the risk-free rate. The Commission proposes to use a 10-day sampling period. This offers a degree of protection from transient volatility while ensuring that the selected rate closely reflects the most recent market activity. Consistent with the application of a 10 year regulatory control period, the Commission proposes to apply the 10 year, ten day moving average for bond rates. This provides a rate of 5.19 per cent.

3.1.4 Expected inflation rate

While the expected inflation rate is not an explicit parameter in the return on equity calculation, it is an inherent aspect of the risk free rate and is also implicit in the cost of debt. There are two sources of information for determining inflationary expectations, financial markets and government estimates. The financial markets indicator of inflation is derived from the difference between the nominal and indexed bonds over a corresponding period. Alternatively, the Commonwealth Treasury releases inflationary forecasts based on internal modelling.

Statement 6.11 of the DRP states:

> The forecast inflation rate will be deduced from the difference in the nominal bond rate and inflation indexed bond rates, and will be deduced for the term corresponding to the duration of the regulatory period. Alternatively, official forecasts may be used.

The Commission adopted this approach in the NSW and ACT and Powerlink revenue cap decisions. However, the maturity dates on the nominal and indexed bonds rarely correspond, requiring realignment using either interpolation or extrapolation. The process of interpolation and extrapolation performs a mathematical line of best fit, estimating an indexed bond rate at a given point in time.

MTC's proposal

MTC has proposed an expected inflation rate of 2.2%. MTC uses the difference between a ten-year bond rate and a ten year indexed bond.

Submissions by interested parties

NERA notes that MTC's has used the difference between the ten-year bond rate and a ten-year indexed bond, which differs from the Commission's use of a five-year horizon to determine the expected inflation rate. NERA also notes that Officer does not use the Fisher Transformation, which is contrary to the practice of the Commission and other regulators, however it states that this has no effect on the nominal vanilla WACC.

Commission's considerations

The Commission notes that the benefit of the approach adopted by the Commission delivers a forward looking estimate of inflation rather than a historic measure. Consistent with the proposal in the draft Regulatory Principles and the method adopted in the ElectraNet and ACT and Powerlink, ElectraNet PowerNet and ElectraNet revenue cap decisions, the Commission will adopt the financial markets expectations of inflation. Using the extrapolated nominal and real bond rate will yield forecasts inflation of 2.11 per cent.

3.1.5 Debt margin and the cost of debt

The cost of debt is the debt margin plus the risk free rate on commercial loans. The cost of debt factor varies depending on the entity's gearing, its credit rating and the term of the debt. The application of the cost of debt to the asset base using the assumed gearing will generate the interest costs for regulatory purposes.

Statement 6.10 of the draft *Regulatory Principles* states:

> The Commission will estimate the cost of debt for a firm conforming to the financial structures implied by the regulatory accounts in consultation with relevant finance agencies.

MTC's proposal

MTC commissioned a report by Professor Bob Officer to examine MTC's capital financing and taxation issues. MTC proposes a debt margin of 150 basis points over the risk free rate (based on an 'A' rated debt), which corresponds to a debt margin of 1.5%. This is based on a rating at the midpoint of the A to BBB+ range. This rating is supported by the fact that MTC is a single asset company, with actual costs higher than the RAB that it submitted, and the resulting impact on financial ratios.

Officer states that the current spread of the bond ratings for 'A' rated debt is 142 basis points (bp) and for 160 bp for 'BBB+' debt, which ElectraNet SA indicated was their rating. Officer also states that the rating for a company such as Murraylink with 60% debt in its capital structure could be expected to be rated between 'A' and 'BBB+' and in these circumstances a reasonable debt margin would be 150 bp.

MTC's debt margin of 1.5% implies a beta of around 0.25%, although Officer has rounded this figure to 0.2%. Officer states that although a debt beta of 0.2 implies a debt margin of 120 basis points, not all of the debt margin will reflect non-diversifiable risk, and that some will reflect diversifiable risk. Officer notes that in the ElectraNet draft decision, the Commission used a debt margin of 130 basis points where ElectraNet argued for 172 bp. Officer states that both numbers could be consistent with a debt beta of 0.2, and that the difference between the margin implied by the beta of 120 bp and a higher number could be explained by diversifiable risk.

Submissions by interested parties

ElectraNet note that in respect of MTC's claim for debt margins of 150 basic points for an A rated company, the Commission applied 110 basic points to SPI PowerNet (also an A rated company) in its December 2002 decision.

Commission's considerations

The risk of an entity's debt is a function of the amount of asset backing, or the degree of leverage or gearing. The greater the debt to asset value or the debt to equity ratio, the greater the risk and, therefore, the debt margin (other things being equal).
In considering an appropriate debt margin for an entity, the Commission adopts industry-wide benchmarks, thus offering an incentive for minimising inefficient debt financing. This is consistent with the DRP.

The calculation of the benchmark debt margin is essentially an empirical matter. It requires the Commission to consider the appropriate benchmark credit rating of the TNSP and the debt margin associated with that rating in the market.

With regard to the credit rating of a service provider, the Commission considers it appropriate to estimate a benchmark rather than use an actual credit rating given that the creditworthiness of the entity is in part under managerial control and the use of a benchmark is consistent with other assumptions. The Commission is of the view that relevant Australian electricity transmission and distribution companies should be used as the basis of a benchmark.

Table 3.3 below sets out the long-term credit rating for ten Australian electricity companies that have been assigned a credit rating from ratings agency Standard and Poor's.

Table 3.3 Credit rating associated with electricity companies

Company	Long-term rating
Country Energy	AA
ElectraNet	BBB+
ETSA Utilities	A-
Energy Australia	AA
Ergon Energy	AA+
Integral Energy	AA
SPI PowerNet	A+
United Energy	A-
Citipower Trust	A-
Powercor Australia	A-

Source: Standard and Poor's website (www.standardpoors.com.au), October 2002.

On the basis of this data, the average credit rating of these entities approximates to an average credit rating of A. The Commission has included both private and government entities in its sample in determining the average credit rating for the electricity industry. The Commission considers that by simply using stand alone and private entities, it would provide too small a sample to obtain an average credit rating for the electricity industry. The Commission notes there could be a wide range of factors as to why the average credit rating for gas companies at BBB+ may be lower then electricity companies. In assessing the credit worthiness of Australian gas companies. [21]

Accordingly, the Commission considers that an A credit rating represents an appropriate proxy credit rating for the benchmark electricity company.

Having established a proxy credit rating, a benchmark debt margin can be determined. Debt is raised by asset owners either through bank markets or through the private and public capital markets. Debt requirements have primarily been met by bank market for projects involving construction in Australia.22

The Commission understands that the interest margin associated with bank issued debt is generally lower than capital market interest margins. However, information on the debt margin associated with bank issued debt is generally not widely available.

[21] Standard and Poor's consider a number of key sources. Specifically, they relate to regulatory risk, counter party risk and overall volumed of demand for gas.[21] Accordingly, the Commission considers that an A credit rating represents an appropriate proxy credit rating for the benchmark electricity company.

[22] Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines,* Report for the ACCC, May 2002. p 7.

The Commission therefore considers that it is reasonable to use capital market data as the benchmark, which is biased in favour of the service provider.

Table 3.2 lists the debt margin which has been adopted in regulatory decisions (although these figures are significantly affected by interest rate levels at the time).

Table 3.2 Debt margin adopted in regulatory decisions

Entity	Industry	Debt margin
ACCC (2002)	Electricity transmission	1.30
QCA (2001)	Electricity distribution	1.65
ORG (2000)	Electricity distribution	1.50
IPART (1999)	Electricity distribution	1.0
IPART (1999)	Electricity distribution	0.80 – 1.0
ACCC / ORG (1998)	Gas transmission	1.20
ORG (1998)	Gas distribution	1.20

As the Commission has adopted a 10 year regulatory control period, it considers it appropriate to determine the debt margin based on a ten-year term. Therefore the Commission will use a debt margin of 145 basic points, combined with a nominal risk –free rate of 5.19 per cent, it suggests a nominal cost of debt figure of 6.64 per cent for the use in the WACC estimates.

3.1.6 Market risk premium

The MRP is the premium above the risk free rate of return that investors expect to earn on a well-diversified portfolio. That is, the return of the market as a whole less the risk-free rate:

$$MRP = R_m - R_f$$

Statement 6.8 of the DRP states:

> The Commission will adopt what it perceives to be the accepted value of the market risk premium available at the time of the regulatory decision.

Under a classical tax system, conventual thinking suggests a value for the MRP of around 6.0 per cent.

While the concept of the WACC and its application for determining regulated revenue is unambiguously forward looking, estimates of the future cost of equity are not readily available. Practical application of the CAPM therefore relies on the analysis of historic returns to equity to estimate the MRP.

In recent revenue cap decisions such as NSW and ACT, Powerlink, SPI and ElectraNet, the Commission adopted a MRP of 6.0 per cent.

MTC's proposal

MTC proposes a MRP of 6.0 per cent, which is consistent with the Commission's previous regulatory decisions. Officer notes that a figure of 6.0 per cent is commonly used in Australia and the US by regulators and academics, although some market participants use more recent data and subjective measures to justify using a lower MRP. Officer provides graphs to demonstrate the justification for a MRP of 6.0 per cent. The ten year period the average and the exponential moving average show a trend towards a 6.0 per cent MRP.

Officer further notes that in the Jardine Fleming Capital partners survey of market participants' MRP expectations for Australia was 5.87 per cent. The survey also found the expectation for the further MRP is approximately 1.0 per cent below this figure. Officer also provides that Australian results are consistent with countries such as the US, UK and Canada whose capital markets are very similar to Australia. Officer notes that the evidence highlighted above points to an estimate of 6.0 per cent for MRP.

Commission's considerations

The Commission's assessment of the MRP suggests that it lay between 5.0 per cent and 7.0 per cent. Furthermore, the above evidence provided by Officer suggests that MRP of 6.0 per cent is appropriate and defensible. Therefore, the Commission proposes a MRP of 6.0 per cent, which is consistent with recent Commission's decisions and MTC's proposal.

3.1.7 Value of franking credits

As stated in the code, under an imputation tax system, a proportion of the tax paid at the company level is, in effect, personal tax withheld at the company level. Australia has a full imputation tax system.

The rate of utilisation of tax credits;γ (gamma) has a significant effect on the WACC. The analysis of imputation credits and its impact on assessed costs of capital in Australia is a developing field and some issues remain contentious.
However, there is little empirical doubt that franking credits do have some value. As stated in Schedule 6.1(5.2) of the code:

> As the ultimate owners of government business enterprises, taxpayers would value their equity on exactly the same basis as they would value an investment in any other corporate tax paying entity. On this basis, it would be reasonable to assume the average franking credit value (of 50 per cent[23]) in the calculation of the network owner's pre tax WACC.

There is considerable debate as to the precise value of franking credits. As with other inputs to the WACC and CAPM equations, selection of a value for this particular parameter is ultimately a matter of judgement having regard to the available empirical evidence.

[23] A study conducted by the Melbourne University Graduate School of Management, which found that franking credits are, on average, valued by equity investors at approximately 50 cents in the dollar.

MTC's proposal

MTC has proposed the value of imputation credits to be 45%. This is the average of studies conducted by the University of Melbourne Graduate School of Management (GSM) and subsequently reviewed by Officer. The GSM studies used dividend drop-off rates and official tax statistics and found that franking credits were, on average, valued by equity investors at approximately 50 cents to the dollar.

However, Officer conducted an updated version of these studies and concluded that a value of 40 cents to the dollar was considered to be more reasonable. Officer points out that there are differences in the sample of dividends between the two studies and his current study. Further, the current study includes smaller companies, which Officer says can be expected to lead to a greater variability in the estimate and a slightly lower estimate, other things being equal. Officer states that the possibility of significant "measurement" errors means that he cannot be emphatic that there has been any change in the value of the credits. However, Officer states that we can be sure that the credits have value and for large, higher dividend paying stock it is likely to average between 40 and 50 cents in the dollar. Officer concludes that 45 cents is a compromise estimate.

Submissions by interested parties

TransGrid notes that Murraylink has used a value of 45 per cent on imputation credits, and that the Commission has consistently used 50 per cent, but WACC notes that the Commission has indicated that this is likely to be reviewed upwards (rather than downward) due to the business tax reforms in June 2000. Although there is not material effect in the vanilla WACC, WACC notes that it will result in the post-tax nomina WACC decreasing to 6.90 per cent.

Commission's considerations

The Commission's regulatory regime attempts to ensure that the return on capital allowance in the revenue cap is equivalent, and only equivalent, to the risk adjusted market rate of return required to maintain investment.

On 30 June 2000 the legislation pertaining to taxation was modified to accommodate the Ralph review recommendations on franking credits. The alteration to the tax law ensures that resident individuals receive the full benefit of franked dividends regardless of their tax position. Previously resident individuals whose taxable income was not sufficient to generate tax expenses sufficient to utilise the franking rebates lost that benefit.

A number of questions have been raised due to the recent tax reforms. First, to what extent if any should foreign investors be recognised. Second, what is an appropriate adjustment to the company tax rate to reflect the benefits of imputation? This adjustment reflects both the utilisation rates for imputation credits and the ratio of credits assigned to company tax paid.

The Commission has concluded on the following in regards to the utilisation of tax credits. First, regarding the issue of recognising foreign investors continued use of a version of the CAPM assumes the national equity markets are segmented rather than integrated. It follows that foreign investors must be completely disregarded and hence the model would recognise that investors would be able to fully utilise imputation credits.

Second, the Commission considers regarding the appropriate adjustment to the company tax rate to reflect the benefits of imputation, the utilisation rate for imputation credits should be set at one, and this follows from the first point above. In addition the ratio of imputation credits assigned to company tax paid should be set at the relevant industry average, which appears to be at or close to one for most industries. These two recommendations imply that the product of the utilisation rate and the ratio of imputation credits assigned to company tax paid (denoted by gamma) should be at or close to 1 for most companies rather than the currently employed figure of 0.50. The effect of this change would be to reduce the allowed output prices of regulated firms.

A consensus view has yet to be reached amongst Australian academics and practitioners for making an adjustment to the rate of utilisation of tax credits. Therefore, the Commission considers that it is inappropriate for it to lead in this area. Hence, a gamma of 0.5 will be used in this decision.

3.1.8 Gearing

A benchmark-gearing ratio needs to be established for WACC to identify the appropriate weighted average cost of debt and equity in the WACC.

The code (Schedule 6.1, 5.5.1) states that:

> gearing should not affect a government trading enterprise's target rate of return…. For practical ranges of capital structure (say less than 80 per cent debt), the required rate of return on total assets for a government trading enterprise should not be affected by changing debt to equity ratios.

MTC's proposal

MTC has proposed a gearing ratio of 60 per cent.

Commission's considerations

The capital structure can have a significant bearing on, not only the debt margin, but also the required return on equity although within "reasonable" bounds it is unlikely to affect the asset cost of capital or the WACC. The greater the level of gearing, the greater the risk of both debt and equity, however, over reasonable ranges, the risk of the total assets does not change. This is because the change in the weighting of capital from equity to debt maintains a constant risk level for the assets as a whole even though the beta measures of both debt and equity will increase.

Table 3.5 below indicates the typical capital structure assumed by regulators has been 60 per cent debt as a proportion of total assets. In theory, within the range of 40 per cent to 70 per cent the asset cost of capital should be stable. The Commission considers that in the circumstances, it would appear that a leverage of between 50 per cent and 60 per cent is a reasonable benchmark. Given that most regulators have adopted a gearing of 60 per cent, which is consistent with this benchmark, there is little compelling reason to vary from this assumption.

Table 3.5 Gearing levels adopted in regulatory decisions

Entity	Industry	Debt/Debt+Equity (per cent)
QCA(2001)	Electricity distribution	60
ESC (2000a)	Electricity distribution	60
ACCC (2000a)	Electricity transmission	60
IPART (1999c)	Electricity distribution	60
IPART (1999d)	Electricity distribution	60
OFGEM (1999)	Electricity distribution (UK)	50
ACCC/ESC (1998)	Gas transmission	60
IPART (1999b)	Gas distribution	60
ESC (1998b)	Gas distribution	60

In the *NSW and ACT , Powerlink, ElectraNet and SPI PowerNet* revenue cap decisions, the Commission adopted a gearing ratio of 60 percent based on industry wide benchmarking. Therefore, the Commission will adopt in the ordinary course of its regulatory decision making process a benchmark-gearing ratio of 60 per cent. However, if the service provider considers there is sound justification for departing from the benchmarked gearing approach, the Commission is receptive to considering such proposals. In this case, the Commission notes that MTC recommended a gearing ratio of 60 per cent.

3.1.9 Betas and risk

Systematic risk is accommodated in the CAPM framework by the equity beta (ße). This indicates the riskiness of one asset or project relative to the whole market (usually represented by the stock market). An equity beta greater than one indicates that the asset or project has returns that vary more than the market average. The risk cannot be eliminated through a well-balanced and diversified portfolio (unlike specific risk).

To compare the risk associated with a number of businesses independent of their financial structure (gearing), equity betas are ‘de-levered’ to produce asset betas (ßa). While there are a number of levering formulae, the Commission consistently applies the formula developed by Monkhouse:[24]

[24] See ACCC, draft *Regulatory Principles*, pp. 79-81.

$$\beta e = \beta a + (\beta a - \beta d)\left[1 - \left(\frac{rd}{1+rd}\right)(1-\gamma)Te\right]\frac{D}{E}$$

Just as the equity beta represents a measure of the systematic risk of a company relative to the market as a whole, the debt beta represents the extent to which the likelihood of the company defaulting on its debt obligations is correlated with movements in market returns.

In July 2002, ACG prepared a report for the Commission which suggested an equity beta for Australian gas transmission companies of just below 0.7.[25] ACG also considered that the data for comparable businesses in the US, Canada and UK. This data produced lower beta estimates and ACG concluded that this secondary information supports the view that Australian estimates are not understated. ACG stated:

> Exclusive reliance on the latest Australian market evidence would imply adopting a proxy equity beta (re-levered for the regulatory-standard gearing level) of 0.7 (rounded-up). Moreover, regard to evidence from North America or UK firms as a secondary source of information does not provide any rationale for believing that such a proxy beta would understate the beta risk of the regulated activities. Rather, the latest evidence from these markets would be more supportive of a view that the Australian estimates overstate the true betas for these activities.[26]

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta estimate of one. ACG notes:

In the future, however, it should be possible for greater reliance to be placed upon market evidence when deriving a proxy beta for regulated Australian gas transmission activities.[27]

Further, the report by ACG indicated that the current appropriate asset beta for Australian gas transmission businesses maybe between 0.27 and 0.37.[28]

MTC's proposal

MTC proposes an asset beta of 0.6, an equity beta of 1.13 and a debt beta of 0.20.

With respect to the debt beta, Officer notes that adopting the debt margin implied by the 150 basis points implies a beta of 0.25, however Officer rounds the estimate o the corporate tax beta 0.2 because any further decimal points gives a spurious impression of accuracy. Further, although a debt beta of 0.2 implies a debt margin of 120 basis points, not all the debt margin is going to reflect diversifiable risk.

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25 ACG, *Empirical evidence on proxy beta values for regulated gas transmission activities,* Final report for the ACCC, July 2002, p. 46.

The result of 0.7 reflects calculations for the equity beta for Australian gas transmission businesses that result in a range of 0.66 to 0.69. The calculations assumed a debt: equity ratio of 60:40 and used data from AGL, Australian Pipeline Trust, Envestra and United Energy. Variables included excluding and including tax from the re-levering formula and a debt beta of either 0 or 0.15.

26 ibid., p. 42.

27 Ibid, p 43.

28 Ibid, p. 40.

Officer presents estimates of equity and asset betas for various companies provided in the recent decision of the Queensland Competition Authority on Regulation of Electricity Distribution, May 2001. The asset beta of the companies listed averages around 0.62 for the reported asset betas and 0.68 if the debt beta in the TNSP is assumed 0.2. Officer notes that in the Australian Graduate School of Management's latest Risk Measurement Service (March 2002), the results indicate an asset beta for the group of around 0.6 for a debt beta assumption of 0.2. Officer notes that the presence of AGL and United Energy in the sample significantly reduced the size of the estimate as weighted averages of the asset β's.

With reference to recent regulatory decisions on betas for electricity and gas, Officer notes that the asset betas are between 0.4 and 0.6 for the decisions, but up to 0.72 in the case of the Commission's decision with respect to AGL pipeline. Officer notes that the omission of a debt beta or implication that it TNSP zero in the regulatory decisions is flawed and inconsistent with the use of a debt margin.

Officer notes that it is difficult to find conclusive evidence for a specific asset beta for electricity distribution. The regulators have opted for a number between 0.4 and 0.6 with most around 0.4. Empirical evidence for the industry would suggest an asset beta of around 0.6. Therefore, on the basis of this Australian data, an asset beta of 0.6 is realistic for Murraylink. Officer refers to international data but notes that not much weight can be put on estimates of an appropriate beta for assets of a TNSP based on the overseas data. Therefore Officer concludes that the best estimate for an Australian TNSP is an asset beta of 0.6.

Submissions by interested parties

NERA also notes that the value of 0.2 used by Officer is high in light of most of the Commission's decisions. NERA indicates that the debt beta is calculated by redefining the CAPM. However the use of observable yields as a proxy for expected returns on debt only holds if lenders have no expectation of default. Given the likelihood of default, expected returns (rather than observable returns) should be used in this transformation. In addition, the Market Risk Premium does not include any debt securities and is instead calculated purely on returns in he Australian equity market.

With respect to the equity beta, NERA notes that an equity beta of 1.13 is higher then the 1.00 used by the Commission in its recent revenue cap decisions. The effect of decreasing the equity beta to 1.00 would be for the return on equity to fall to 11.40 per cent and for the vanilla WACC to fall to 8.70 per cent.

Commission's consideration

In the Commission's previous revenue cap decisions for Powerlink, SPI PowerNet and ElectraNet SA, the Commission has used an equity beta estimate of 1. This suggests that the business experiences the same volatility as the market in general. This does not appear to be consistent with the frequently held view that gas and electricity utilities are less risky and more stable than the market average. Greater stability suggests that the equity beta should be less than one.

Further, the Commission refers to the ACG report that suggested that AGSM data implies an equity beta estimate of 0.7 for Australian gas transmission companies. However, for the reasons indicated by ACG in reference to the equity beta as noted above, the Commission considers that it may be premature to rely on market data exclusively when determining the equity beta. Accordingly, the Commission considers that an equity beta of 1, while biased in favour of the service provider is appropriate for MTC at this time. The Commission is currently assessing the merits of relying on market data and providing the service provider with a "generosity factor" of approximately 0.3 for the equity beta as part of its review of the MTC.

The Commission has adopted a debt beta of 0 in its recent revenue cap decisions for MTC and MTC PowerNet. The relationship between the debt margin ($(rd - rf)$) and the debt beta (βd) is illustrated from the formula:

$$\beta d = \frac{rd - rf}{MRP}$$

The Commission in the past considered that a regulated entity with a guaranteed revenue stream would have a low systematic default risk. However, the Commission considers that it may be more appropriate to incorporate a positive debt beta in its future electricity regulatory decisions. Further, the ESC has recently undertaken work to provide further insight into the debt beta. It concluded that the debt beta is likely to be between 0 and 0.18 although a value toward the upper end of this range was more likely.[29] ACG also considered this information and suggested that an appropriate range for the debt beta would be between 0 and 0.15.[30] The Commission understands the difficulty and complexity of determining a specific number for the debt beta. Given the wide range of equity betas coupled with the de/re levering of the equity beta with the same debt beta. Furthermore, the systematic risk of default appears to be insignificant in the context of MTC. On balance, the Commission considers that an appropriate value for the debt beta is 0.

In regard to the asset beta, the Commission understands that it is very difficult to find any conclusive evidence for a specific asset beta for electricity transmission networks. The Commission has taken the consistent line of using past regulatory decisions in coming up with the best asset beta estimate. From this information the Commission considers that an appropriate range for electricity distribution and transmission assets is between 0.35-0.50. Table 3.6 outlines the approach taken in recent regulatory decisions in relation to asset betas for electricity and gas. Therefore the Commission proposes an asset beta of 0.4 is appropriate.

[29] ESC, *Draft Decision: review of gas access arrangements,* July 2002, pp. 231-233.
[30] Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities,* Final report for the ACCC, July 2002, pp. 28-29.

Table 3.6 Recent regulatory decisions on asset betas for electricity and gas

Matter	Industry	Asset beta
ESC, Price determination	Electricity Distribution	0.40
MTC, Snowy Mountains	Electricity Transmission	0.40
MTC, MTC & ACT	Electricity Transmission	0.35-0.50
MTC, Queensland	Electricity Transmission	0.40
MTC, Elect, DB's	Electricity Distribution	0.35-0.50
QCA, Price Determination	Electricity Distribution	0.45

Accordingly, throughout the application of the Monkhouse formula noted above, the equity beta for MTC will be 1.0. This represents the absolute upper limit of a possible range for the equity beta suggested by ACG's analysis of available empirical evidence.

3.1.10 Treatment of taxation

In recent decisions, the Commission applied the existing statutory company tax rate of 30 per cent. This was within the context of difficulties in determining a satisfactorily accurate long-term effective tax rate as part of the pre-tax real framework being used at the time. The capital-intensive nature of electricity utilities has historically meant that the effective tax rate for such networks has been less than the statutory tax rate[31]. As noted above, the Commission considers that moving to the post-tax nominal framework which uses that effective tax rate has the potential to generate more appropriate and cost-reflective revenue cap outcomes.

The effective tax rate is defined as difference between pre-tax and post-tax rates of return. It is sensitive to a number of factors, which include the corporate tax rate and the range of available tax concessions that serve to lessen tax liabilities or defer them to a later period. Although the tax rate on accounting income is always at the corporate tax rate, in any year the income assessable for tax purposes can be quite different from the net revenues available to the business. The timing aspect and the fact that taxes are assessed on the basis of nominal income means that the prevailing inflation rate also has a significant impact on the effective tax rate. The effect that deferral of tax has on the timing of cash flows does not generally cause administrative difficulties for a corporate entity that is well accustomed to uneven cash flows.

[31] According to IPART calculations, the average effective tax rate paid by the NSW distributors amounted to 25 per cent in 1996/97 (see IPART, The Rate of Return for Electricity Distribution Networks, Discussion Paper, November 1998, p. 9).

MTC’s proposal

MTC assumes that the effective tax rate is equal to the statutory tax rate of 30 per cent.

Submissions by interested parties

MTC notes that officer assumes that the effective tax rate is equal to the statutory tax rate of 30 per cent. Although this does not change the vanilla MTC it does mean that the post-tax nominal MTC calculated by Officer overstates the required MTC. If Murraylink writes down the value of its asset base as a consequence of gaining regulated status, as implied by MTC’s application, then it is likely that there will be significant carried forward tax losses and lower on-going profits, so that the effective tax rate over the life of the asset would be less than 30 per cent.

Commission’s considerations

For the purposes of determining the cost of capital, the code requires the Commission to maintain competitive neutrality. The Commission adopted an effective tax rate of 20.65 per cent, which was derived from the financial model. The Commission notes that the MTC is a partnership. Therefore, tax is paid by the partners of the company and the tax rate is based on personal income tax rate. The Commission notes that the assumption of a statutory 30 per cent tax rate may not be appropriate, and in the case of MTC a higher tax rate may be appropriate.

3.1.11 Conclusion

The Commission has carefully considered the values that should be assigned to MTC’s cost of equity given the nature of its business and current financial circumstances. Accordingly, the parameter values used are the most appropriate, as justified by the above arguments, and summarized in the table 3.7 below.

Table 3.7 Comparison of cost of capital parameters proposed by MTC and the Commission

Parameters	MTC's proposal	Commission's parameter
Gearing ratio (D/V) %	60%	60%
Asset beta β_a	0.60	0.4
Debt beta	0.2	0
Equity beta	1.13	1.00
Debt margin (over R_f) %	1.50%	1.45%
Market risk premium (R_m-R_f) %	6.00%	6.00%
Nominal risk free interest rate (R_f)%	5.4%	5.19%
Expected inflation rate (F) %	2.2%	2.11%
Cost of debt $R_d = R_f +$ debt margin %	6.90%	6.64%
Value of imputation credit	45%	50%
Nominal post tax return on equity	12.15%	11.17%
Post tax nominal WACC	6.97%	6.74%
Pre tax nominal WACC	9.96%	8.96%
Pre tax Real WACC	7.76%	6.72%
Vanilla WACC	9.00%	8.45%

Preliminary View

The Commission has calculated a post tax nominal return on equity of 11.17%

3.2 Operating and maintenance expenditure

The Commission, as part of its process for determining MTC's MAR, has assessed both MTC's proposed operating and maintenance expenditure (opex) with regard to future demand and service quality, and the proposed opex of the Alternative Projects. The Commission has adopted this approach to ensure that the appropriate amount of opex is included in MTC's revenue requirement, bearing in mind that the regulatory asset value of Murraylink is based upon the lowest cost Alternative Project.

The remainder of this chapter:

- sets out the requirements of the code (section 3.2.1);
- summarises the Commission's preliminary view concerning the appropriate level of opex to be allowed in the present regulatory period as well as the information considered by the Commission in arriving at that conclusion. This includes:
  - MTC's opex proposal, and the opex proposal for the Alternative Projects, for the regulatory period (section 3.2.2);
  - a summary of the major findings of PB Associates' review (section 3.2.3);
  - submissions by interested parties (section 3.2.4);
- sets out the Commission's considerations (section 3.2.5); and
- a summary of the Commission's conclusions in this regard (section 3.2.6).

3.2.1 Code requirement

The Commission's task in assessing Murraylink's opex is specified in the code. Clause 2.5.2(c) requires that upon conversion to a prescribed service, the Commission may adjust the revenue cap in accordance with Chapter 6 of the code. In particular, Part B of Chapter 6 requires *inter alia* that:

- in setting the revenue cap, the Commission must have regard to the potential for efficiency gains in expected operating, maintenance and capital costs, taking into account expected demand growth and service standards; and
- the regulatory regime must seek to achieve an environment which fosters efficient use of existing infrastructure, efficient operating and maintenance practices and an efficient level of investment.

To undertake its task, the Commission needs to make informed decisions on the adequacy, efficiency and appropriateness of the opex planned by Murraylink to meet its present and future service requirements. To this end, the Commission engaged PB Associates to review Murraylink's opex program as well as the estimated opex of the Alternative Projects. The results of PB Associates' review are summarised in section 3.2.3.

3.2.2 MTC's application

Murraylink's proposed opex

In a letter submitted on a confidential basis to the Commission on 7 April 2003, MTC provided a revised schedule of forecast opex which is summarised below:

Murraylink Transmission Company Pty Ltd on behalf of Murraylink Transmission Partnership (2003 $M, excluding GST):

July-Dec 03	2004	2005	2006	2007	2008	2009	2010	2011	2012
2.19	4.37	4.47	4.46	5.91	4.44	4.44	4.43	4.42	5.88

MTC submitted the revised opex forecast for the following reasons:

- The original application made in October 2002 contained an opex forecast based on MTC's best estimate of costs at that time. Now that it is operational, MTC has more accurate information relating to costs, leading to the revised forecast.
- Insurance premium quotes have now been received from brokers.
- A maintenance quote has also been received from a contractor.

MTC has provided a letter to the Commission from PricewaterhouseCoopers who reviewed the forecast opex in accordance with Australian Auditing Standards that apply to review engagements.

Proposed opex of Alternative Projects

Burns and Roe Worley (BRW), consultants to MTC, have advised that the opex calculated for the Alternative Projects was based on 1.5% to 1.8% of the estimated capital cost of those projects. The cost estimates included development works, transmission line costs, switchyard costs, contractors' profit and overheads, and interest during construction.

Therefore, the proposed opex for those Alternative Projects has been calculated as follows (note: only Alternatives 1, 2 and 3 have been included for examination as they provide the same services as those provided by Murraylink):

Alternative Project	Capital cost estimate ($M) (including contingency)	Opex ($M pa)
Alternative 1	245.9	3.6
Alternative 2	206.3	3.4
Alternative 3	201.6	3.5

3.2.3 Consultant's report

PB Associates were engaged by the Commission to undertake a review which analyses and comments on matters in relation to the contribution of opex to MTC's delivery of transmission services. PB Associates have also undertaken a review of the opex forecasts of the Alternative Projects, particularly Alternative 3, for the purposes of determining the regulatory asset value of Murraylink.

Due to the short duration of this review, in-depth investigations have not been possible. Where PB Associates has expressed a professional opinion based on limited information available, follow-up has been recommended.

PB Associates considers that many of the costs proposed by MTC are realistic, but that MTC appears to have taken a conservative approach to some areas. Key findings of PB Associates' review of the MTC application and associated documents are:

- Staffing levels - although probably appropriate in the short-term, appear to be high over a 10-year period.
- Opex costs remain stable except for circuit breaker replacement. PB Associates considers that there should be some efficiency gains projected in the forecasts.
- Maintenance expenditure - replacement of mechanisms and key components of circuit breakers at 5 yearly intervals, rather than complete circuit breakers would be more appropriate than what MTC have presently allowed. This should result in lower expenditure at years 5 and 10.
- ABB provides spares at their cost until the end of the general warranty period in April 2007. In 2007 and 2012, provision in opex has been made for spares to replace or overhaul filters, disconnectors and reactors in addition the circuit breaker requirements.
- On going costs are all opex in nature with no capital costs associated with refurbishment or replacement activities identified by MTC.
- No joint or common cost issues have been identified, as MTC has advised that all services and purchases are dedicated to Murraylink. There appears to be some potential for MTC to improve efficiencies by sharing resources with associated companies in their Brisbane office. Should this occur, PB Associates recommends that MTC be required to advise the Commission of the allocation mechanisms to be used, and the overall reduced revenue requirement.
- Connection costs are reasonably consistent throughout the 10 year period. PB Associates recommends that the Commission gives consideration to the inclusion of connection assets into the regulatory asset base of the respective TNSP as this could result in lower connection costs.
- MTC direct opex costs are comparable with Transpower NZ HVDC thyristor pole (using solid state technology as for MTC) costs. Overhead (non-direct) costs for MTC are 57% of overall costs compared with other Australian TNSP rates of 30-45%. While MTC does not have the same economies of scale as other TNSPs, 57% is considered to be high.
- Overall opex costs are 2.1% of the MTC asset based compared with 1-2.5% for other TNSPs on a similar replacement cost basis.

Key findings for the Alternative Projects are:

- The route length of 25km for 220kV cabling allowed in Alternative 3 (and other AC alternatives) is considered to be high.

- The $2M/km cost of underground cabling allowed in Alternative 3 appears to be high and PB Associates considers that an allowance in the range of $1M to $1.5M per km would be adequate.
- Estimates for phase shifting transformers appear to be high by up to $5M for each of the AC alternatives.
- BRW estimated $3.4m opex costs for an HVDC option (Alternative 2) with 86% of the line in overhead line instead of all underground cable for MTC. MTC costs are significantly higher at $4.5M.
- The $3.5M opex cost estimated for Alternative 3 is considered to be high.

3.2.4 Submissions by interested parties

Submissions have mainly focussed on the issues of conversion and determination of the regulatory asset value. There has been limited comment on MTC's proposed opex. ElectraNet SA comments that consumers should only pay the opex that would have been attributable to an efficient augmentation that passed the regulatory test.

3.2.5 Commission's considerations

In reaching its views regarding the appropriate amount opex to be allowed, the Commission has taken into account the review by PB Associates and the comments of interested parties. The Commission has determined the regulatory asset value of Murraylink based on the lowest cost Alternative Project, which is Alternative 3 (the Red Cliffs – Monash 220kV AC overhead line). As described earlier, the Commission has adjusted the base cost estimate of Alternative 3 using an ODRC methodology. BRW have advised that the opex of the Alternative Projects, including Alternative 3, was estimated at 1.5% to 1.8% of the capital cost of those projects.

The Commission considers that the estimated opex of Alternative 3 is the appropriate cost to factor into the calculation of Murraylink's MAR, rather than the proposed opex of Murraylink itself. This is consistent with the Commission's overall approach of referencing the costs of Alternative 3 to establish the regulatory asset value of Murraylink. The Commission considers that the opex allowance should be calculated as 1.5% of Alternative 3's capital cost, bearing in mind the findings of PB Associates' review.

3.2.6 Conclusion

Taking into account the reduced capital base determined by the Commission ($114.42 million in 2003 rising to $123.41 million in 2006 – see section 2.3), the estimated opex of Alternative 3 for the regulatory period is as follows (nominal $M, excluding GST):

Oct-Dec 03	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
0.43	1.82	1.86	1.90	1.94	1.98	2.02	2.06	2.11	2.15	1.10

Accordingly, the Commission grants this opex for inclusion in the revenue requirement of Murraylink.

3.3 Pass-through events

3.3.1 Introduction

Under the code, the Commission is required to administer an incentive-based form of regulation. Incentives are created for managers to pursue ongoing efficiency gains through controlling their expenditures. However, some costs are essentially uncontrollable by nature and therefore cannot properly be subject to the same incentive measures.

Cost pass-throughs provide a mechanism for dealing with this problem. As an alternative to receiving an allowance in its cash flows, a TNSP may transfer the financial impact of the event to parties that are better placed to handle those costs.

It is envisaged that the range of potential pass-through events will be limited. The Commission seeks to achieve a balance between the interests of TNSPs and customers, with no windfall gains or losses accruing to TNSPs as a result of events beyond their control.

The Commission considers that a pass-through event must have the following characteristics:

- the event should be identified in advance with its scope precisely defined – this enables the following tests to be applied and is considered necessary for good, transparent regulation. A high degree of certainty is provided where the Commission and the TNSP agree up front on the events to be covered by pass-through arrangements. However, the Commission recognises that unidentified events may also be allowed for in a pass-through regime, providing they adhere to the tests below.

- the event must be beyond the control of the TNSP – these are exogenous, unpredictable events, the cost of which cannot be built into the TNSP's expenditure forecasts, requiring an alternative mechanism to deal with them.

- the financial impact of the event must be material – these are the type of events that may occur infrequently but can have a significant financial impact on the business. Setting a materiality threshold limits the applications a TNSP can make, for the purposes of administrative efficiency.

- the event affects the TNSP, and not the market generally – systematic or market risk should be addressed in the WACC parameters. Firm-specific risks should be dealt with in the cash flows or through a pass-through mechanism. On that point, the Commission considers that some events should not be the subject of a self-insurance allowance as the potential financial impact may be too significant and uncertain for the TNSP to assume. Any allowance calculated may prove insufficient with the TNSP still needing a cost pass-through eg. deductibles for insurance policies.

- the financial impact of the event is better borne by parties other than the TNSP – by its nature, a pass-through transfers risk to other parties. This will only be appropriate where the TNSP cannot reasonably be expected to bear the risk itself, for example, in the case of uncontrollable events that may otherwise affect the commercial viability of the business. Costs that would properly have been allowed for in the TNSP's revenue requirement, if predictable and quantifiable at the time of its revenue cap application, would fall into this category.

3.3.2 General operation of the pass-through mechanism

The Commission considers the following matters are important features of an efficient and equitable pass-through mechanism:

- the Commission reserves the right to initiate pass-through reviews at its discretion.

- the pass-through mechanism should accommodate both positive and negative amounts in the interests of both TNSPs and customers.

- a 40 business day assessment period to allow full assessment of pass-through event applications, including public consultation where appropriate, to be undertaken by the Commission. The Commission, at its discretion, may also extend this period to adequately assess pass-through proposals.

- the provision by the TNSP of detailed documentary evidence in support of any pass-through application. Sufficient detailed information must be provided which substantiates that the aggregate costs facing the TNSP have increased or decreased as a consequence of the claimed pass-through event. Wherever possible, this information should also be provided in the public domain.

- a TNSP must annually (at least 50 business days prior to the start of the financial year) provide the Commission with a copy of insurance premium invoices, irrespective of whether a pass-through event application has been submitted in that year.

3.3.3 MTC's proposed pass-through rules

Turning to the application at hand, MTC proposes that the pass-through mechanism would operate for five categories of events:

- a Change in Taxes Event;

- a Service Standards Event;

- a Non-contestable Capital Works Event;

- a Terrorism Event; and

- an Insurance Event.

The Commission recognises that certain events are outside the control of MTC and has considered MTC's proposals in the light of its recent GasNet and SPI PowerNet decisions. With the exception of the Non-contestable Capital Works Event, the Commission generally approves such arrangements, with the amendments outlined below. MTC's proposed pass-through rules are detailed in its letter dated 4 April 2003 to the Commission.

3.3.4 Submissions by interested parties

TransGrid comments that Murraylink should receive the same pass-through arrangements approved by the Commission in its SPI PowerNet revenue cap decision.

International Power (Australia) comments that pass-throughs should be denied by the Commission or stringent conditions applied until market wide arrangements are implemented.

ElectraNet SA supports cost pass-throughs for unforseen and unpredictable events. Such pass-throughs, however, should be consistent with the Commission's recent decisions and should apply to all TNSPs.

3.3.5 Commission's considerations

The Commission has assessed Murraylink's proposed pass-through arrangements under the tests for pass-through events detailed above.

Amendments required to proposed pass-through event definitions

The Commission considers that the definition of a Change in Taxes Event should be amended as follows (changes in bold text):

> 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); or
>
> (b) the removal **of a Relevant Tax** or imposition of a new Relevant Tax,
>
> to the extent that the change, **removal** 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.

The Commission also requires the following amendments to the definition of Relevant Tax (changes in bold):

> 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;
>
> but excludes
>
> **(c)** income tax (or State equivalent tax) and capital gains tax;
>
> **(d)** penalties and interest for late payment relating to any tax, rate**,** duty, cha**r**ge, levy or other like or analogous impost;
>
> **(e)** fees and charges paid or payable in respect of a Service Standards Event;
>
> **(f)** stamp duty, financial institutions duty, bank accounts debits tax or similar taxes or duties;
>
> **(g)** any tax, rate, duty, charge, levy or other like or analogous impost which replaces the taxes and charges referred to in (c) to (f).

In relation to a Service Standards Event, MTC defines such an event to mean:

> 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 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 the 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.

The Commission requires that the above definition be amended to delete paragraph (iii) relating to connection or revenue recovery contracts. It is the view of the Commission that such changes are beyond the reasonable scope of a Service Standards Event which essentially deals with changes to the activities undertaken and the minimum standards imposed on a TNSP.

The Commission also requires that the definition of "Authority" be amended to delete the reference to VENCorp and ElectraNet SA as they are not considered to fall under the general category of a government or regulatory body, such as the Commission or NEMMCO.

Exclusion of a Non-contestable Capital Works Event as a pass-through event

MTC has proposed the following pass-through event:

> 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.

The Commission does not consider that a Non-contestable Capital Works Event should be included as a pass-through event. In its SPI PowerNet decision, such matters were dealt with outside the pass-through arrangements and the Commission believes, for the purposes of consistency, that it should adopt the same position here.

Generally, under the SPI PowerNet approach, non-contestable capital works are the subject of a separate contract between the TNSP and the customer. At the next revenue reset, the TNSP may seek to have the augmentation included in its regulated asset base.

Preliminary View

The Commission will grant opex based on 1.5% of the lowest cost alternative. It will also allow pass-through for the following events:
- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

3.4 Total revenue

The previous chapters discussed each of the major elements of the Commission's building block approach to setting Murraylink Transmission Company's (MTC) revenue cap. This chapter brings this work together, along with a discussion of depreciation and other related matters, to set out the Commission's decision on MTC's revenue cap from 1 October 2003 till 30 June 2013.

3.4.1 Code requirement

The code requires the Commission to set a revenue cap with an incentive mechanism for non-contestable transmission network services. The Commission's role as regulator of transmission revenue is limited to determining the MAR while MTC will calculate the resulting network prices in accordance with Chapter 6, part C of the code.

The code outlines the general principles and objectives for the transmission revenue regulatory regime to be applied by the Commission. The code also grants the Commission the flexibility to use alternative, but consistent, methodologies. In fulfilling its role as regulator, the Commission's aim is to adopt a process which eliminates monopoly pricing, provides a fair return to network owners, and creates incentives for owners to pursue ongoing efficiency gains through cost reductions.

3.4.2 The accrual building block approach

The Commission's decision on MTC's MAR relies on the accrual building block approach, while having regard to financial indicators. The basic building block approach calculates the MAR as the sum of the return on capital, the return of capital and opex (non-capital expenditure) and taxes.

The Commission notes that the possibility of pass-through items has been incorporated to reflect the business environment that MTC will face in the future. The revised building block formula thus becomes:

MAR = return on capital + return of capital + opex + taxes ± service standards

= (WACC * WDV) + D + opex + taxes ± service standards

where:

WACC	=	post-tax nominal weighted average cost of capital;
WDV	=	written down (depreciated) value of the asset base;
D	=	depreciation allowance;
opex	=	operating and maintenance expenditure
taxes	=	income tax liability allowance and
service standards	=	ACCC performance incentive scheme

However, in determining the MAR, the code requires the Commission to take into account the service standards that TNSPs are expected to maintain. Therefore, the Commission will adopt an annual service standard adjustment in the calculation of MAR, that is:

$$MAR_t = \text{(allowed revenue)} + \text{(financial incentive)}$$

$$= (AR_t) + \left(\frac{(AR_{t-1} + AR_{t-2})}{2} \times S_{ct} \right)$$

Where:

MAR = maximum allowed revenue

AR = allowed revenue

S = service standards factor

t = regulatory period

ct = calendar year

3.4.3 MTC's proposal

In its application, MTC proposes that the calculation of the revenue, upon conversion occurring, for a 10 year regulatory period. MTC's proposed revenue has been determined on the basis that its initial regulatory asset base is $176 million.

MTC proposes a revenue cap, which includes:

- for an eight month period 1 May 2003 to 31 December 2003 of $17.2 million;
- from 1 January 2004 to 31 December 2008, a revenue of $27.1 million; and
- from 1 January 2009 to 31 December 2012, a revenue of 90.1 million.

A summary of MTC's "raw" and smoothed proposed revenue is presented in table 4.1.

Table 3.1 Revenue Requirement, 2003 to 2012 (nominal $m)[32]

	Financial years ending 31 December									
	2003[1]	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**
Operating & maintenance	2.5	3.7	3.8	3.8	3.9	4.0	4.1	4.1	4.2	4.3
Depreciation	6.1	9.2	9.2	9.2	9.2	7.6	6.8	6.8	6.8	6.8
Nominal return on capital	10.5	15.6	15.1	14.5	14.0	13.4	12.9	12.4	12.0	11.5
Less RAB indexation for inflation	(2.5)	(3.5)	(3.1)	(2.8)	(2.4)	(2.3)	(2.1)	(1.8)	(1.5)	(1.2)
Net tax allowance	0.6	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
Raw revenue requirement	**17.2**	**26.0**	**25.9**	**25.8**	**25.7**	**23.7**	**22.6**	**22.6**	**22.5**	**22.4**
Smooth revenue requirement	**17.2**	**25.5**	**25.2**	**24.9**	**24.6**	**24.3**	**24.0**	**23.7**	**23.4**	**23.2**

1 This is data for an eight month period, 1 May 2003 to 31 December 2003.

[32] Source: MTP forecasts.

3.4.4 The Commission's assessment of building block components

The Commission's assessment of the various components of the revenue cap, in the context of the building block framework, is discussed below. The Commission notes that MTC's revenue path is based upon a 10 year regulatory control period. As discussed in the cost of capital chapter, the Commission considers that a 10 year regulatory period is appropriate in this case since there appears to be little scope for opex efficiency gains and substantially small amount of capex proposed by MTC.

Asset valuation

In order to establish the appropriate return on the funds invested in MTC, the Commission has modelled MTC's asset base over the life of the regulatory period and estimated a weighted average cost of capital (WACC) based on the most recent financial information. The Commission has applied an ODRC valuation.

The basic methodology underlying the roll-forward of MTC's asset base is that the closing value of the asset base from year to year is constructed by taking the opening value, converting it to a nominal figure by adding in an inflation adjustment, adding in any capital expenditure and subtracting disposals and depreciation for the year. The closing value for one year's asset base becomes the opening value for the following year's asset base. Under the post-tax nominal framework, this methodology is modified slightly to account for two regulatory issues, which will be discussed in the Depreciation section below.

As discussed in chapter 3 titled Regulatory Asset Valuation, the Commission considers in line with an ODRC valuation that alternative 3 provides the lowest cost project. The Commission found that certain aspects of the costing of the alternative projects were overstated, and consider that undergrounding and controllability costs were unnecessary. In line with SEIL's recommendation, the Commission has adopted a P50 for contingencies. Furthermore, the Commission has adjusted interest during construction to account for the cost decreases. Therefore, MTC's initial regulatory asset value, operating expenditure and revenue requirement is based upon alternative 3 costs.

In terms of modelling the movement in MTC's asset value over the regulatory period, the Commission has, for the purposes of this indicative view, indexed this opening asset value by 2.11 per cent per annum, which is consistent with the inflationary expectations used in deriving the WACC. Therefore, the Commission considers that MTC's opening asset value is $114.42 million.

Capital expenditure

In MTC original application, it had included $8.97 million in additional investments in the regulatory asset base. MTC has since advised that that it will make a decision to progress the network augmentations based upon the Commission's final decision including the quantum and rationale of Murraylink's regulatory asset value. MTC notes that if it proceeds with the augmentations in July 2003, it is likely that phase 1 could be complete in July 2004 and phase 2 could be complete in July 2005.

At this stage, the Commission proposes to include the full costs of the augmentation. As the expected timing of these investments is after 2003, the investment should be included as future capex in deriving MTC's revenue requirement for the proposed regulatory period. The Commission has distributed the portions of the investment into their respective proposed financial years. However, the Commission notes that the inclusion of the augmentations may be subject to change as the Commission works towards understanding the precise level of overlap between MTC's proposed augmentations and unbundled SNI, and whether TransGrid is willing to be a proponent for Unbundled SNI.

The Commission will include, $8.97 million (in real terms), in nominal terms $10.26 million of capital expenditure in the calculation of MTC's revenue cap for the purpose of this indicative view.

Depreciation

Using a post-tax nominal framework, the Commission has made allowance for "economic depreciation" which adds together the (negative) straight line depreciation with the (positive) annual inflation effect on the asset base.

This economic depreciation has been used to model the movements of asset values over the life of the regulatory period (table 3.2) and for determining the return of capital (table 3.3). Calculation of the applicable straight-line depreciation component has been based on the remaining life per asset class.

On the basis of this approach the Commission has calculated a straight-line depreciation allowance that trends from $0.01 million from 1 October 2003 till 31 December 2003 to $0.27 million, $0.33 million, $0.67 million, $0.53 million, $0.61 million, $0.69 million, $0.77 million, $0.86 million and $0.95 million in each of the following full years. For the period 1 January 2013 to 30 June 2013, the economic depreciation has been calculated at $0.52 million.

Weighted average cost of capital

In determining MTC's revenue cap, the Commission must have regard to MTC's WACC. The WACC is a method commonly used for determining the return expected on an asset base.

While the WACC framework provides a well-recognised theoretical model for establishing the cost of capital, there is less than full agreement on the precise magnitude of the various financial parameters that need to be applied. The Commission has given careful consideration to the value that should be assigned to MTC. Accordingly, the parameter values used are those considered most appropriate.

The Commission has chosen to apply a post tax nominal return on equity of approximately 11.17 per cent, which equates to a post-tax nominal vanilla WACC of 8.45 per cent. In arriving at those figures, the Commission has adopted:

- a nominal risk free interest rate of 5.19 per cent, reflecting the short term average yield on ten year Commonwealth Government bonds;
- a real risk free rate of 3.02 per cent based on the short term average yield on ten year capital indexed bonds;
- an expected inflation rate of 2.11 per cent derived from the difference between the two yields;
- a debt margin of 1.45 per cent above the nominal risk free interest rate leading to a nominal pre-tax cost of debt of 6.64 per cent.

The Commission has examined market evidence and accepted the advice of financial experts in determining a market risk premium of 6 per cent and a dividend imputation figure (gamma) of 0.5.

The Commission has examined the risks faced by MTC and the equity betas of similar businesses in arriving at an asset beta of between 0.30 and 0.50. This range is derived principally from the average equity beta for the infrastructure and utilities industry group listed on the Australian Stock Exchange. Using a gearing assumption of 60 per cent and a debt beta of 0.00, this converts to a possible range for the equity beta of between 0.75 and 1.25. Taking the midpoint of this range returns an equity beta for MTC of just below 1.

The Commission's chosen post tax nominal return on equity of 11.17 per cent lies below MTC's proposal of a nominal post tax return on equity of 12.12 per cent. This largely reflects the prevailing market conditions and MTC's contention that it requires a higher rate of return to reflect the level of risk faced by its network from competing energy sources.

Based on the above components, the Commission has modelled MTC's asset base over the life of the regulatory period (see Table 3.2). Note that, under the post-tax nominal framework adopted by the Commission, the return on capital building block has been calculated using the nominal vanilla MTC (8.45 per cent) consistent with the post-tax MTC determined from the cost of capital parameters.

Table 3.2 MTC's return on capital, 1 October 2003 to 30 June 2013 ($ nominal million)

	Financial year ending 30 December										
	2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Opening asset base	114.42	114.41	114.14	113.82	123.41	122.88	122.27	121.58	120.81	119.95	119.00
Capital expenditure	-	-	-	10.26	-	-	-	-	-	-	-
Economic depreciation	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
Closing asset base	114.41	114.14	113.82	123.41	122.88	122.27	121.58	120.81	119.95	119.00	118.48
Return on capital	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03

1 This is data for a three month period, 1 October 2003 to 31 December 2003.
2 This is data for a six month period, 1 January 2013 to 30 June 2013.

Operating and maintenance expenses

As the Commission has adopted Alternative 3 as the lowest cost alternative for the purposes of determining the regulatory asset value of Murraylink, it will also adopt Alternative 3's operating and maintenance expenditure to the amount of $19.37 million ($nominal) over the regulatory period.

Estimated taxes payable

Based on the assumptions underlying the above building block components and taking into account the network's tax depreciation profile, the Commission assesses MTC as being in a positive tax paying position during the regulatory period.

The Commission's assessment of taxes payable are based on the 60 per cent gearing level assumed in the WACC parameters. Further, the tax estimates relate only to the network's regulated activities. The Commission's estimated taxes payable trend from $0.22 million from 1 October 2003 to 31 December 2003, $0.98 million for the first full year of the regulatory period to $1.21 million for 31 December 2012. for the period from 1 January 2013 till 30 June 2013 the tax estimate is $0.62 million.

Total revenue and CPI-X smoothing

Based on the various elements of the building block approach, the Commission propose a smoothed revenue allowance that increased from $2.97 million from 1 October 2003 to 31 December 2003 to $12.25 million, $12.49 million, $12.74 million, $12.99 million, $13.25 million, $13.51 million, $13.78 million, $14.05 million and $14.33 million in the subsequent full years of the regulatory period (Table 3.3).

Table 3.3 MTC's MAR to 2013 ($ nominal million)

	Financial year ending 30 December										
	2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Return on capital	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03
Return of capital	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
Operating expenses	0.43	1.82	1.86	1.90	1.94	1.98	2.02	2.06	2.11	2.15	1.10
Estimated taxes payable	0.22	0.98	1.00	1.02	1.12	1.14	1.16	1.18	1.20	1.21	0.62
Less value of franking credit	0.11	0.49	0.50	0.51	0.56	0.57	0.58	0.59	0.60	0.61	0.31
Unadjusted revenue allowance	2.97	12.25	12.33	12.69	13.46	13.54	13.62	13.70	13.77	13.84	6.95
Smoothed MAR	**2.97**	**12.25**	**12.49**	**12.74**	**12.99**	**13.25**	**13.51**	**13.78**	**14.05**	**14.33**	**6.95**

1 This is data for a three month period, 1 October 2003 to 31 December 2003.
2 This is data for a six month period, 1 January 2013 to 30 June 2013.

In arriving at its Preliminary View the Commission notes that its proposed revenue cap is approximately 50 per cent lower than MTC's proposed revenue cap.

The difference between MTC's proposed MAR and the Commission's MAR is largely the result of:

- a lower value for the RAB arising from the selection of a adjusted Alternative 3 costs
- different cost of capital parameters used in deriving the post-tax nominal return on equity and
- a significant reduction in opex.

3.4.5 Conclusion

On the basis of the Commission's forecast inflation, the Commission has determined a revenue cap for MTC that increases from approximately $2.97 million for the period 1 October 2003 to 31 December 2003, to $14.33 million for the year ending 31 December 2012. For the subsequent half year (1 January 2013 to 30 June 2013) the revenue is estimated at $6.95 million.

Preliminary View

On the basis of its building block approach the Commission has determined a revenue cap for MTC that increases from approximately $2.97 million for the period 1 October 2003 to 31 December 2003, to $14.33 million for the year ending 31 December 2012. For the subsequent half year (1 January 2013 to 30 June 2013) the revenue is estimated at $6.95 million.

3.5 Service Standards

3.5.1 Introduction

TNSPs commonly have a meshed network, which limits the impact of any given service standards 'event' on the entire network. In effect, the meshed network provides several alternative paths, via which, electricity can be delivered. If an event occurs on one path, another may still be used to deliver electricity.

However MTC's network is, conceptually, a single line that connects two transmission networks. This means that an event on this single path could cause the delivery on electricity to cease until the outage has been corrected. Such an event has the potential to impact on inter-state competition in upstream and downstream markets.

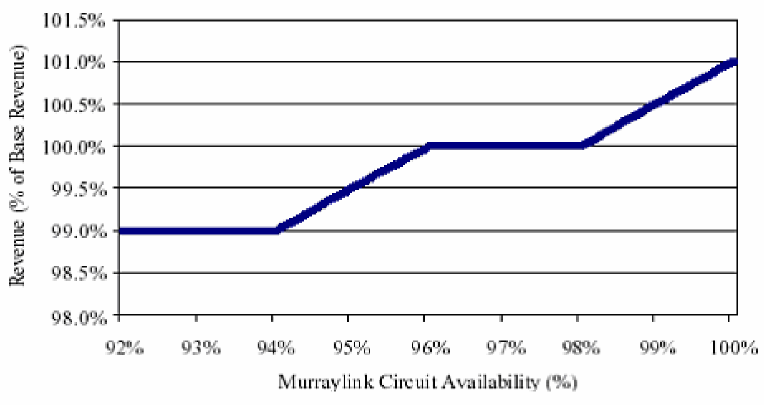
The Commission engaged Sinclair Knight Merz (SKM) to recommend a performance-incentive scheme for transmission networks. SKM's report is available on the Commission's internet site (http://www.accc.gov.au).[33]

3.5.2 MTC's application

MTC's application proposes a simple incentive scheme, which is similar to parts of the scheme recommended by SKM.[34] MTC proposed a single total availability measure, with a target of 96-98% availability. Lower than 96% would result in penalty and above 98% would result in reward.

MTC proposed that both the penalties and rewards be capped at 1% of the regulated revenue. This target was proposed for 10 years and Figure 3.1 shows the scale of the penalty and rewards.

Figure 3.1 MTC's proposed incentive scheme



MTC also proposed that these performance targets be applied on a monthly basis. Its proposal used the manufacturer's specifications and information from a CIGRE study to derive the availability targets.

33 Sinclair Knight Merz (November 2002), Transmission network service provider (TNSP) Service Standards.

34 Sinclair Knight Merz (November 2002), Transmission network service provider (TNSP) Service Standards.

3.5.3 PB Associates report

PB Associates evaluated SKM's approach and recommended a similar performance-incentive framework. SKM's report used the TNSP's own historical performance data to set performance targets and because such historical performance data was not available for the Murraylink interconnector a different approach to setting performance targets was used.

PB Associates started by reviewing MTC's proposed service standards and concluded that the single availability measure is not appropriate. However PB Associates also concluded that MTC's method to set performance targets is a viable method.

PB Associates recommended different performance targets and more performance measures, which are shown in Table 3.1 below after reviewing the technical documents released by the manufacturer (ABB) of much of Murraylink's assets and the CIGRE survey, which are both referenced in its report.

Table 3.3 - PB Associates recommended targets

Measure	Performance for maximum penalty (%)	Target performance (%)	Performance for maximum reward (%)	Weight (%)
Planned circuit energy unavailability (Figure 3.2)	99.32	99.45	99.66	40
Forced outage circuit energy availability in peak periods (Figure 3.3)	98.8	99.38	100	40
Forced outage circuit energy availability in off-peak periods (Figure 3.4)	98.8	99.40	100	20

Figure 3.2 - Planned circuit energy availability

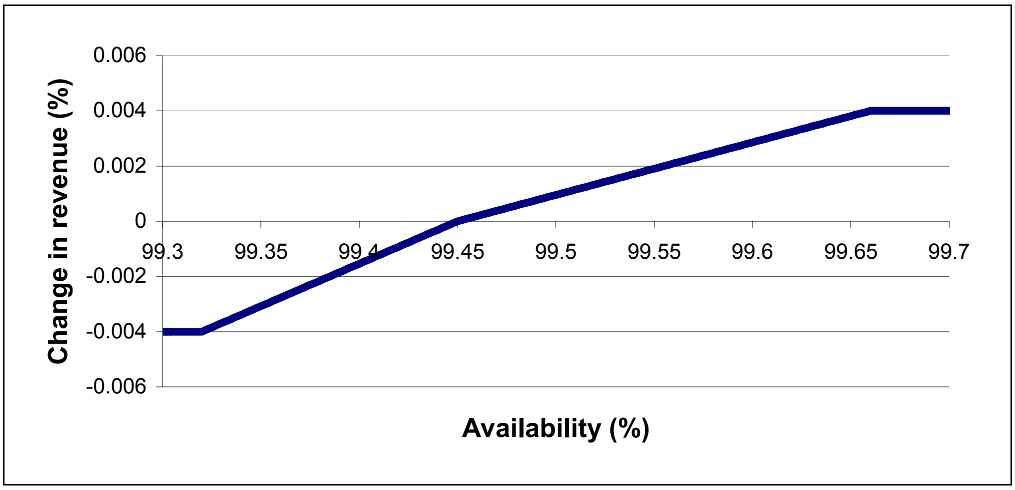


Figure 3.3 - Forced outage circuit energy availability in peak periods

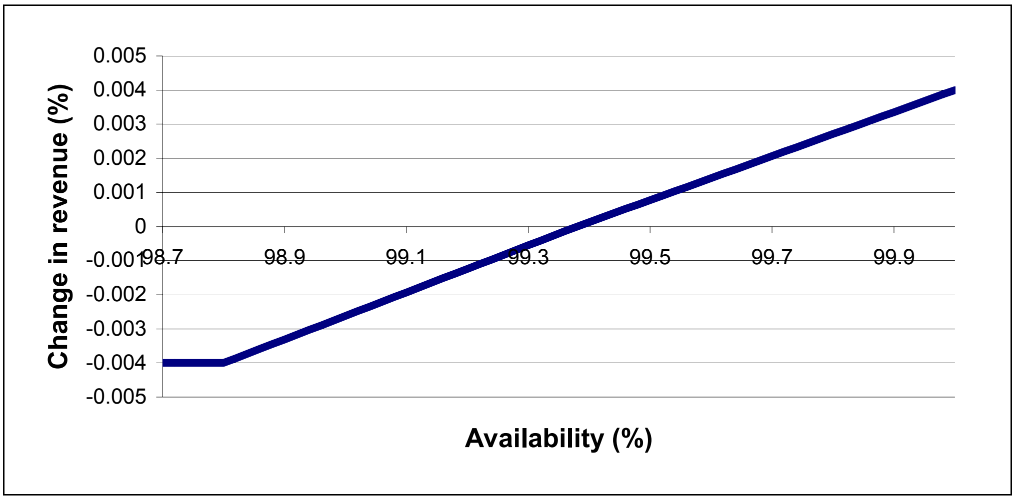
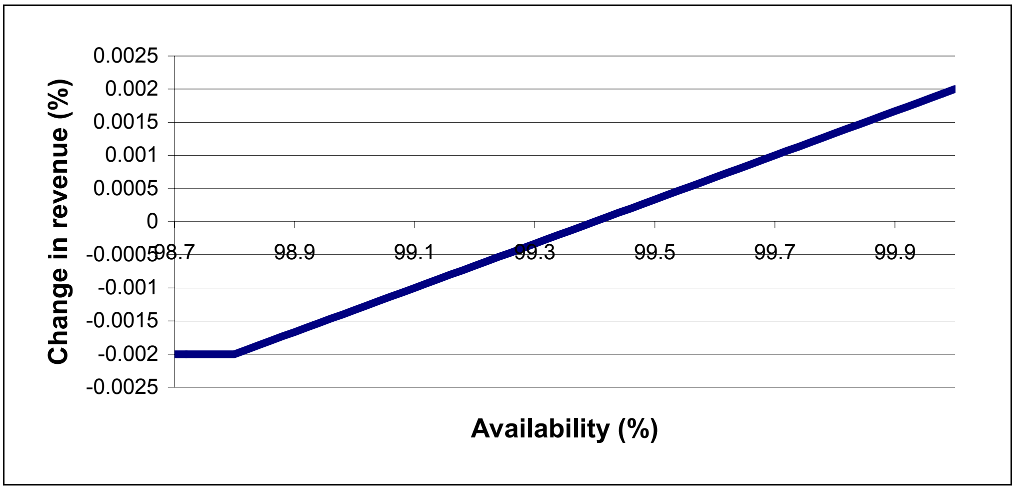


Figure 3.4 - Forced outage circuit energy availability in off-peak periods



3.5.4 Submissions by interested parties

International Power supports MTC's view that the availability measure is the only suitable performance measure to be applied to Murraylink, however is concerned that the availability measure in its simplest form is unable to reflect the impact of Murraylink on the NEM. International Power and ElectraNet indicate that there is no service history on the performance of Murraylink from which to determine an acceptable performance level.

TransGrid agrees with MTC that circuit availability is an appropriate performance measure for Murraylink. However, NRG Flinders, TransGrid and EUAA note that the target reliability factor of 97% appears to be low. NRG Flinders and EUAA further are of the view that the incentive scheme amounting to 1% also appears to be too low. ElectraNet is generally supportive of the comments made by PB Associates with respect to MTP's proposed service standards. However it indicates that the service standards for Murraylink should be those service standards that would apply to the optimal plant technology and configuration required to service the market.

ESIPC suggests that further definition of performance measures may be necessary to adequately reflect the combination of both Murraylink and Electra Net's transmission networks in contributing to the Riverland service standards. In all other aspects, ESIPC concurs with the recommendations made in the PB Associates' report. Ergon Energy believes that if the network service provided by Murraylink is determined to be a prescribed service then it must meet the same service standards as imposed upon other regulated interconnectors in the NEM.

EUAA recommend that if the Commission accept a low targets and incentives for Murraylink it should ensure that there is scope to make adjustments to this area over time, especially under a 10-year regulatory period.

3.5.5 Commission's considerations

PB Associates' recommendation builds on both SKM's review of service standards and MTC's proposal. It uses the basic SKM incentive framework and a variation of MTC's method to set performance targets.

Availability measure

MTC's proposal did not consider the difference between forced and planned outages. MTC's proposal would provide an incentive to minimise its aggregate planned outages per month only. It does not give any incentive to displace outages from peak to off-peak times, nor does it provide any incentive to minimise forced outages.

PB Associates' recommendation recognises that there needs to be incentives placed on MTC to minimise both planned and forced outages. It also recognises that it is more valuable to restore a forced outage quicker in peak periods than in off-peak periods.

PB Associates believe that planned outages need not be broken into peak and off-peak times because NEMMCO can influence what planned outages can proceed.

Different incentives

MTC's proposed one measure, availability, means that MTC simply must concentrate on maximising availability. It does not consider the time of the event and it excludes certain force majeure events.

For example, when a force majeure event damages the link the required repairs would be excluded from the availability statistic. There would be no incentive for MTC to carry out the repairs in the quickest possible time, rather at the least possible cost to MTC.

The addition of forced outage energy availability means that MTC's response to a forced outage is accounted for. MTC will not be penalised for a force majeure event, rather it will be given the incentive to react as quickly as possible to a force majeure event. PB Associates recommend that a higher value be placed on Murraylink when such a forced outage occurs during peak times.

Preliminary View

The Commission considers that only circuit availability is required for a transmission system comprising only a single circuit interconnector, and concurs with PB Associates' view that circuit availability be subdivided into:

- planned availability
- forced availability during peak periods and
- forced availability during off-peak periods

The Commission also believes that associated performance targets should be set for each category rather than a single overall target. Taken together, the three targets represent a cumulative unavailability of 1.77%.

Commission's Preliminary View

The Commission's Preliminary View can be summarised as follows

In accordance with its obligations under the code, the Commission determines Murraylink's services to be classified as prescribed service and therefore proposes conversion of Murraylink from a market network service to a prescribed service. As a result, the Commission will determine a maximum allowable revenue (MAR) for MTC, in accordance with Chapter 6 of the code subject to the outcomes of the regulatory test.

The Commission is satisfied that if the additional augmentations are in place then Murraylink's rated capacity will be 220 MW.

The Commission accepts that Murraylink delivers gross market benefits ranging from $136 million to $300 million under most credible scenarios, with the median being around $190 million.

The Commission's proposed amendments to the cost of the alternative projects suggests that Alternative 3, which is an overhead AC line between Red Cliffs and Monash, is the lowest cost alternative. As a result, Alternative 3 satisfies the regulatory test and, for the purposes of determining MTC's regulatory asset value and opex costs the Commission proposes to use adjusted Alternative 3 in determining MTC's MAR.

The Commission will grant opex based on 1.5% of the lowest cost alternative. It will also allow pass through for the following events:
- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

On the basis of its building block approach the Commission has determined a revenue cap applying for a regulatory period of 10 years for MTC that increases from approximately $2.97 million from 1 October 2003 to 31 December 2003, $12.25 million from 1 January 2004 to 31 December 2004 to $14.33 million for 31 December 2012. For the period 1 January 2013 to 30 June 2003 a revenue of $6.95 million.

Appendix A – Submissions

AGL

Australian Landscape Trust

BJ Walker

C Ashton

D Fisher

D Macfarlane

D Spain

ECCSA, ElectraNet SA & EUCV

ElectraNet SA

EME

Ergon

ESCOSA

ESIPC

EUAA

EUCV

F Rattray

G Benson

GS & JE Knight

GJ & SA McNally

Integral Energy

International Power

J & D Lambie

J Lowe

J McFadzean

K Barnett

L Hanlon

M Comerford

M Middleton

M Wall

Mildura Rural City Council

Ministry for Energy (NSW)

Murraylink Transmission Company

NERA on behalf of TransGrid

NRG Flinders

P Secombe

Power Down Under

Powerlink

R Caton

R Walker

S Cousin

S Davis

S Paterson

Santos

TransGrid

VENCorp

W.H.G Uren

Wentworth Shire Council

Willow Vale Residents Group

Appendix B Letter to ACCC from Planning SA

Planning SA

Contact Officer: Lee Webb
Telephone: (08) 8303 0750
Facsimile: (08) 8303 0753
Reference: PLN/00/0115(8)

AUST. COMPETITION & CONSUMER COMMISSION MELBOURNE
1 - 7 APR

Department of Transport and Urban Planning
136 North Terrace
Adelaide
GPO Box 1815
South Australia 5001
DX 56601
Telephone (08) 8303 0600
Facsimile (08) 8303 0604
www.planning.sa.gov.au

3 April, 2003

Louis Tirpcou (Assistant Director)
Regulatory Affairs – Electricity
Australian Competition and Consumer Commission
GPO Box 520J
MELBOURNE VIC 3001

FILE No:
DOC: D03/13891
MARS/PRISM:

Dear Mr Tirpcou

Re: Murraylink Transmission Company Application for Regulated Status

Following our meeting on 5 March 2003 at Planning SA, to discuss the implications of the environmental assessment process for the SA-NSW (SNI) Interconnector proposal (by TransGrid) for the Murraylink Interconnector application, the following advice is provided:

- The SNI proposal is currently at the government assessment stage. Planning SA anticipates that an Assessment Report may be completed by late April/early May 2003. It should be noted that this timeline is dependent upon the timing of assessment of Commonwealth matters (land tenure and environmental aspects) by Environment Australia, pursuant to the *Environment Protection and Biodiversity Conservation Act 1999*.

- A preliminary assessment of the SNI proposal indicates that the SA/NSW border-Monash section of the line will result in significant environmental impacts, particularly for migratory/threatened bird species that use the wetlands north of Renmark (especially the Riverland Wetlands Ramsar Site). Thus, this section of the proposed line is questionable from an environmental perspective. Whilst undergrounding of the line will be discussed in the Assessment Report, it will have significant cost implications (including the subsequent economic impact on energy consumers who would ultimately have to pay any additional construction costs through the imposition of charges by NEMMCO), and to a lesser degree, additional environmental impacts (esp the greater level of vegetation clearance likely to be required).

- The assessment is likely to recognise an alternative route to the Monash Substation, via an alignment south of the River Murray from the SA/Vic border and a river crossing at Lyrup (ie just SE of the Monash Substation). Essentially, this is a 'hybrid' of the current proposal and the previous proposal for an interconnector completely south of the River Murray. The level of environmental risk and cost implications of a river crossing will be taken into consideration when deciding whether undergrounding would be required in this circumstance.

- Environment Australia has questioned the route through Calperum Station (north of Renmark) due to significant environmental impacts and the effect on the use of Commonwealth land that forms a large part of the Bookmark Biosphere Reserve. The joint

Government of South Australia

owner of the land (ie the Australian Landscape Trust under a Deed of Trust) has advised the Commonwealth that the proposed route through Calperum and Taylorville Stations is not supported unless it is undergrounded. If the Commonwealth Minister does approve the proposal, it is possible that undergrounding through environmentally sensitive areas (ie from the SA/NSW border to Monash Substation) will be considered. Undergrounding is less relevant along the southern boundary of Taylorville Station, where the proposed line follows an existing, cleared transmission line easement.

- Any transmission line alignment from Red Cliffs-Monash may not require undergrounding. Undergrounding of river crossings for the Murraylink Interconnector was part of the development application by TransEnergie and was not a requirement of any approval.

- Any proposed transmission line from Robertstown-Monash or Heywood-South East is unlikely to require undergrounding, unless alternative routes could not be found to avoid environmentally sensitive areas, mainly significant wetland systems (such as the Bool/Hacks Lagoon Ramsar Site in the South East)

A copy of the *Guide to the Assessment of Major Developments or Projects* (including a flow chart of the assessment process) can be found at the following website:

http://www.planning.sa.gov.au/pub-pdf/27p.pdf

At this stage, the advice provided is only preliminary and subject to change during finalisation of the Assessment Report.

I hope that this information assists you in your deliberations.

Yours sincerely

Lee Webb
SENIOR ENVIRONMENTAL OFFICER
ENVIRONMENTAL IMPACT ASSESSMENT UNIT