Decision

Murraylink Transmission Company Application for Conversion and Maximum Allowed Revenue

1 October 2003

File no
M2002/468

Commissioners

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Glossary

ABB	ABB Power System AB of Sweden
AC	Alternating Current
ACG	Allen Consulting Group
AR	Allowable Revenue
BRW	Burns and Roe Worley
Capex	Capital expenditure
CAPM	Capital Asset Pricing Model
CMA	Coastal Management ACT 1995
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
DSE	Department of Sustainability and Environment (Victoria)
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
EPBC Act	Environmental Protection and Biodiversity Conservation Act 1999
ESIPC	Electricity Supply Industry Planning Council (South Australia)
EUAA	Energy Users Association of Australia
EUCV	Energy Users Coalition of Victoria
GSM	Melbourne Graduate School of Management

HVDC	High Voltage Direct Current
IOWG	Interconnector Options Working Group
IPART	Independent Pricing and Regulatory Tribunal (NSW)
IRPC	Inter-Regional Planning Committee
KBR	Kellogg Brown and Root Pty Ltd
LRMC	Long-run Marginal Cost
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
NET	National Electricity Tribunal
NPV	Net Present Value
NSP	Network Service Provider
ODRC	Optimised Depreciated Replacement Cost
ODV	Optimised Deprival Value
Opex	Operating and maintenance expenditure
Panel	Joint Advisory Panel (Basslink)
PST	Phase-Shifting Transformer
QCA	Queensland Competition Authority
QNI	Queensland – New South Wales Interconnector
RAB	Regulated Asset Base
RAV	Regulatory Asset Value

Saha	Saha Energy International Ltd
SEC	State Electricity Commission of Western Australia
SKM	Sinclair Knight Merz
SNI	South Australia –New South Wales Interconnector
SRMC	Short Run Marginal Cost
SVC	Static-Var Compensator
TEA	TransEnergie Australia
TEUS	TransEnergie United States
TNO	Transmission Network Owner
TNSP	Transmission Network Service Provider
TPA	Trade Practices Act 1974
TSC	Thyristor Switched Capacitors
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 operated by the Murraylink Transmission Company (MTC) on behalf of Murraylink Transmission Partnership (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 220 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 allowed revenue (MAR) 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. Clause 2.5.2(c) 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.

Conversion of Murraylink to a prescribed service

Process for 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's discretion. No express criteria is provided to guide the regulator in exercising its discretion.

Submissions raised suggest that an MNSP should demonstrate that the NEM has changed since its decision to construct a market network service, or there are incremental benefits from conversion. However, the Commission is of the view that it is appropriate to focus its assessment on whether or not the Murraylink service is a prescribed service. The Commission has taken this view for a number of reasons.

Firstly, the Commission notes that the intention of the National Electricity Code Administrator (NECA) Working Group was to provide a right for an MNSP to apply for conversion to ensure that investment is not inefficiently inhibited[1].

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 apparent intention 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 determined a regulatory asset value for Murraylink in the same way that the regulatory asset value for other new investments by TNSPs are determined. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass 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 efficient transmission investment in the NEM.

Code obligations

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 must consider is whether Murraylink would be a prescribed service if it were not covered by the Safe Harbour Provisions. If Murraylink satisfies 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 MTC.

[1] Further discussion on the intent of the NECA working group is on p.22.

"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 none of the definitions 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).

The Commission believes that Murraylink satisfies the first and second limb of its working definition. However, with regard to the third limb, 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 considers that Murraylink satisfies the working definition of a prescribed service, and that MTC is subsequently entitled to be converted.

Process for making a conversion determination

As noted, 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. In its Preliminary View, the Commission outlined its understanding at that time of the requirements of clause 2.5.2(c). In particular, the Commission outlined in its Preliminary View that the Commission's ability 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. On this basis, the Commission proposed to proceed by way of releasing a Position Paper setting out its position on MTC's conversion application and revenue cap, and issuing a formal determination once advised of the details of Murraylink ceasing to be classified as a market network service.

In finalising its views, the Commission has given further consideration to the requirements of clause 2.5.2(c) and the appropriate process for finalising the assessment of MTC's application. In particular, the Commission is concerned to ensure that its determination is properly coordinated with the requirements for Murraylink ceasing to be classified as a market network service. Further, the Commission is mindful that the processes ought to proceed smoothly within the technical requirements for the operation of the NEM. In this regard, the Commission has been advised by MTC that, subject to consideration of the Commission's decision, MTC's intention is to terminate the classification of Murraylink's network service as a market network service.

Consequently, the Commission has finalised its assessment of MTC's application and made its determination without setting out its position in a prior position paper. However, in accordance with clause 2.5.2(c) the Commission's determination is expressed to not take effect until the existing service ceases to be classified as a market network service. The Commission has also set a time period within which this must occur.

Asset Valuation

The regulatory test and conversion

In its Preliminary View, the Commission determined MTC's opening asset value based on the outcomes of the regulatory test. MTC argues that its extended Optimised Depreciated Replacement Cost (ODRC) valuation methodology is consistent with the requirements set out in Chapter 6 of the code.

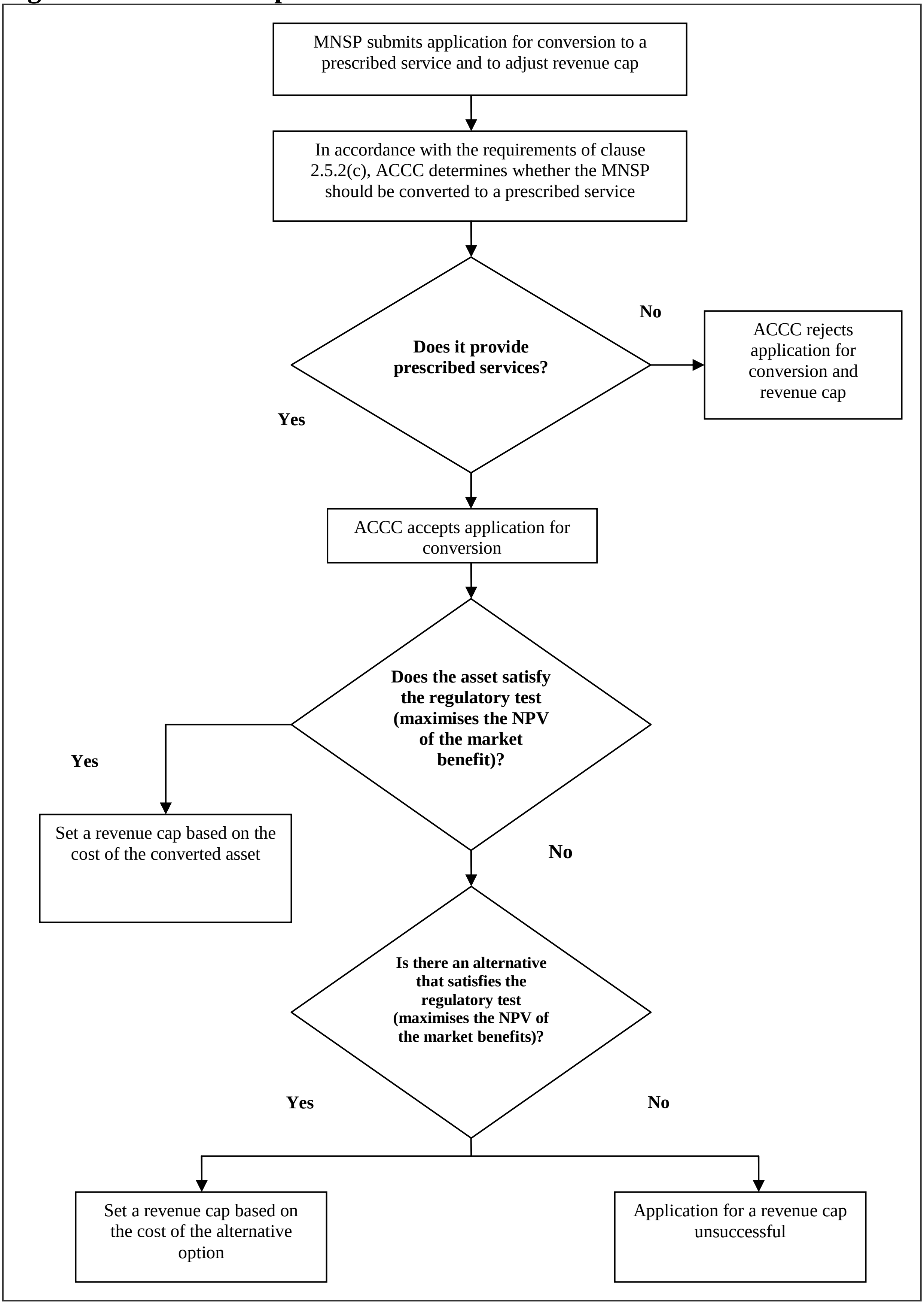
However, the Commission still believes that the use of the regulatory test to determine the opening asset base for Murraylink is justified by the need to ensure that a person seeking to convert a market network service to a prescribed service under clause 2.5.2(c) is treated in the same manner as a person seeking approval under Chapter 5 to construct a new network asset in order to supply a prescribed service. The outcomes of the regulatory test assessment are consistent with the requirements and objectives of Chapter 6 of the code.

Further, the Commission is of the view that the regulatory test will produce an outcome that is consistent (even if not identical) with the outcome that would be achieved using an ODRC valuation methodology and is consistent with the requirements of Chapter 6 of the code.

The Commission has used the regulatory test to assess MTC's conversion application.

The Commission's process in assessing a conversion application is outlined in Figure 1, which is intended to aid the reader's understanding.

Figure 1 – Conversion process



Selection of alternative projects

The regulatory test states:

> "A *new interconnector or an augmentation option* satisfies this 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;"

MTC proposed the following alternative projects, and configured them so that they would provide the "exact same level of technical service" as Murraylink:

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; and

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.

In considering MTC's selection of alternative projects, the Commission believes that alternative projects should contain a level of similarity to the Murraylink, although they need not be technically identical. That is, an alternative project could be considered a reasonable alternative if it delivers substantial gross market benefits to all regions and or nodes. In the case of Murraylink, its benefits largely arise from its ability to transfer power to South Australia as well as to the Riverland region of South Australia.

A number of alternative proposals to MTC's alternatives were considered by the Commission including Heywood A (an upgrade to the existing Heywood interconnector) and Horsham A (a new transmission line connecting Horsham and Tailem Bend). The Commission did not consider these proposals to be reasonable alternatives, given that they do not provide power transfers to the Riverland region. Should Murraylink's benefits only have come from its ability to transfer power from Victoria to South Australia, it is likely that the Commission may have considered the Heywood augmentation an alternative project to Murraylink. However, the Commission notes that it has considered the Heywood interconnector in the context of Alternative 4, which also includes an augmentation to the Riverland region.

The Commission notes that it cannot consider some of MTC's proposal without considering the supporting augmentations[2]. Therefore, in line with the findings of the Supreme Court of Victoria on the South Australia-New South Wales Interconnector

[2] The Commission's reference to augmentations or augmentations to the Victorian network in this Decision is reference to the augmentations set out in VENCorp's submission of 15 August 2003

(SNI) appeal, where relevant, the Commission has included the augmentations to the Victorian network.

The Commission considers the following projects are reasonable alternatives:

Project Name	Location and specifications
Murraylink	Red Cliffs to Monash 140 kV DC underground transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 1	Buronga to Monash 275 kV AC mostly overhead transmission line, initially operating at 220 kV, with substation augmentations at Buronga and Monash, including augmentations to the Victorian network.
Alternative 2	Red Cliffs to Monash 140 kV DC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 3	Red Cliffs to Monash 220 kV AC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 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.

Power transfers

The power transfer capability of an augmentation is a critical input into the calculation of its market benefits. The greater the transfer capability of an augmentation the greater its potential market benefits as assessed under the regulatory test.

Following the analysis of power system transfers by MTC and VENCorp the Commission is satisfied that given the appropriate technical configuration, the power transfer capacity of Murraylink, Alternative 1, Alternative 2 and Alternative 3 at peak times will be 220MW as long as there are augmentations to the Victorian network. The power transfer capability of Alternative 4 will also be 220 MW, without augmentations to the Victorian network.

Power transfer capability – MW

Project name	Power Transfers
Murraylink	220
Alternative 1	220
Alternative 2	220
Alternative 3	220
Alternative 4	220

Gross Market Benefits

In undertaking an assessment under the market benefits limb of the regulatory test, the Commission must consider the market benefits of the Murraylink project and its alternatives. The greater the need for the interconnector and the augmentations 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 benefits associated with competitive, non-electricity, market activities as the test is to be used to assess the merits of regulated electricity network assets.

In its application, MTC provided a limited number of sensitivities and market development scenarios in its assessment of the gross market benefits of Murraylink and its alternative projects. The Commission's preference is to use the regulatory test where credible market development scenarios and sensitivities are considered to determine the robustness of the outcomes of the regulatory test.

The Commission has considered the gross market benefits of Murraylink and its alternative projects under a range of market development scenarios and sensitivity analysis, in order to ensure that projects which pass regulatory test are robust to different assumptions about the future development of the market. In response to submissions and the Commission's consultant, Saha, MTC provided the gross market benefits of Murraylink and its alternative under a number of market development scenarios and sensitivities. The Commission has assessed these, and considered the comments of interested parties and its consultant Saha. The Commission considers that the gross market benefits of Murraylink and its alternative projects range from approximately $166 million to $347 million. The market simulation suggests the credible range is between $170 to $220 million.

Cost of alternative projects

In its Preliminary View, the Commission did not believe that a phase-shifting transformer (PST) was necessary to facility power system transfers. However, work undertaken by MTC and VENCorp supports a PST for Alternatives 1 and 3. The Commission has therefore made an allowance for an PST. However, while the Commission still believes there is a need for voltage support, following advice from ElectraNet and VENCorp on the need for voltage support in South Australian, the Commission has reduced the allowance and size of a static-var compensator (SVC).

The level of spares was raised by a number of interested parties. In terms of a spare PST, the Commission notes the requirements of a South Australian Transmission Code. MTC argues that spare PST is required by the South Australian Transmission Code. However, the Commission believes that a spare standard transformer is sufficient to meet the requirements of the South Australian Transmission Code. It has therefore adjusted the cost of the relevant alternative projects to include an allowance for a spare standard transformer, not a spare PST. More generally the Commission considers that an appropriate allowance for spares is 1 per cent of switchyard costs.

The Commission also believes that an allowance for profit and overhead, interest during construction, and contingency is appropriate.

In regard to undergrounding, the Commission in its Preliminary View concurred with MTC's proposed undergrounding for Alternative 1, but did not believe that undergrounding would be required for Alternatives 2 and 3. The Commission still remains of this view.

The Commission believes that the case for undergrounding has not been made by MTC. This conclusion is based on the fact that there are no legislative or policy requirements for undergrounding as acknowledged by MTC and its consultant, Kellogg Brown and Root (KBR). Further, the submissions of various transmission planners and the SA Government agree that undergrounding would have been unlikely for the route traversed by Murraylink, and that acceptance of undergrounding in remote areas could set costly precedents for future transmission projects.

The Commission has also taken into consideration the 2001 Victorian Electricity Distribution Price Review published by the Essential Services Commission (ESC). The ESC does not make an allowance in the regulatory asset base of various distribution businesses for undergrounding, and argues that the cost of undergrounding should be borne by the proponent.

Based on its analysis the Commission has determined the following costs for the various alternative projects:

Cost of alternative projects ($million)

Project name	Cost of interconnector	Cost of the augmentations	Life cycle O&M costs	Total Regulatory Cost
Murraylink	$179	$15	$46	$240
Alternative 1	$194	$15	$36	$245
Alternative 2	$142	$15	$34	$191
Alternative 3	$97	$15	$30	$142
Alternative 4	$136		$30	$166

Ranking of alternative projects

In accordance with the requirement of the regulatory test, the Commission has ranked the various alternatives. Based on the ranking of the various alternative projects, the Commission considers that Alternative 3 satisfies the regulatory test in that it maximises the net present value of the benefit to the market having regard to its alternatives, timings and market development scenarios. The Commission will therefore use the cost of Alternative 3 ($97.33 million) as the opening asset value for the purposes of setting MTC's MAR.

Ranking of alternative projects ($ millions)

Project name	GMB Minimum	GMB Maximum	Regulatory Cost	Ranking
Murraylink	$166	$347	$240	4
Alternative 1	$166	$347	$245	5
Alternative 2	$166	$347	$191	3
Alternative 3	$166	$347	$142	1
Alternative 4	$169	$350	$166	2

Cost of Capital

In determining MTC's revenue cap, the Commission must have regard to MTC's Weighted Average Cost of Capital (WACC). In arriving at this figure, the Commission has adopted:

- a nominal risk free interest rate of 5.46 per cent, reflecting the short term average yield on ten-year Commonwealth Government bonds;
- a real risk free rate of 3.32 per cent based on the short term average yield on ten-year capital indexed bonds;
- an expected inflation rate of 2.07 per cent derived from the difference between the two yields;
- a debt margin of 0.86 per cent above the nominal risk free interest rate leading to a nominal pre-tax cost of debt of 6.32 per cent.

The Commission's chosen post tax nominal return on equity of 11.44 per cent lies below MTC's proposal of a nominal post tax return on equity of 12.15 per cent. The table below provides a comparison of the cost of capital parameters proposed by MTC, and those granted in the Commission's Preliminary View and Final Decision.

Comparison of cost of capital parameters

Parameters	MTC's proposal	Preliminary View	Final Decision
Gearing ratio (D/V) %	60%	60%	60%
Asset beta β_a	0.60	0.4	0.4
Debt beta	0.2	0	0
Equity beta	1.13	1.00	1.00
Debt margin (over R_f) %	1.50%	1.45%	0.86%
Market risk premium (R_m-R_f) %	6.00%	6.00%	6.00%
Nominal risk free interest rate (R_f)%	5.4%	5.19%	5.46%
Expected inflation rate (F) %	2.2%	2.11%	2.07%
Cost of debt R_d = R_f + debt margin %	6.90%	6.64%	6.32%
Value of imputation credit	45%	50%	50%
Nominal post tax return on equity	12.15%	11.17%	11.44%
Vanilla WACC	9.00%	8.45%	8.37%

Opening asset base

Based on the cost of the option which maximises the benefit to the market, the Commission has modelled MTC's asset base over the regulatory period. The Commission's modelling is outlined in the table below.

The Commission notes that its has removed the capital expenditure allowance granted in the Commission's Preliminary View for the proposed augmentation to the Victoria network, THE Commission believes these augmentations can be accommodated in VENCorp's MAR under the Victorian arrangements.

MTC's return on capital ($millions nominal)

	Financial Year Ending 30 June									
	2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Opening asset base	97.33	97.22	97.03	96.78	96.48	96.13	95.72	95.26	94.73	94.14
Economic depreciation	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65
Closing asset base	97.22	97.03	96.78	96.48	96.13	95.72	95.26	94.73	94.14	93.49
Return on capital	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89

[1] This is for a nine month period, 1 October 2003 to 30 June 2004.

Opex

The Commission has based its operating and maintenance expenditure (opex) determination on the estimated costs of Alternative 3, the project that maximises the net present value of the market benefits under the regulatory test. Taking into account PB Associates' opex reviews, the views of interested parties and the Commission's analysis of efficient costs, the Commission grants opex totalling $32.71 million (nominal) over the regulatory period, as follows:

MTC's opex allowance ($ millions, nominal)

2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66

[1] This is for a nine month period, 1 October 2003 to 30 June 2004

Pass-through rules

The Commission has taken into consideration MTC's proposals for the inclusion of certain pass-through arrangements into its revenue cap, and submissions from interested parties. The Commission concludes that the Change in Taxes Event, Service Standards Event, Terrorism Event and Insurance Event meet the guidelines expressed in section 6.2, with the stated amendments. However, the Commission does not accept the Non-contestable Capital Works Event or the Essential Contract Event.

Total Revenue

Based on the various elements of the building block approach, the Commission proposes a smoothed revenue allowance that increases from $8.90 million for the nine month period commencing 1 October 2003 to 30 June 2004, to $11.88 million, $11.99 million, $12.09 million, $12.19 million, $12.29 million, $12.40 million, $12.50 million, $12.61 million and $12.72 million in the subsequent full financial years of the regulatory period. The proposed smoothed revenue is presented in the following table.

MTC's MAR from 1 October 2003 to 30 June 2013 ($million, nominal)

	Financial year ending 30 June									
	2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Return on capital	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89
Return of capital	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65
Operating expenses	2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66
Estimated taxes payable	0.79	0.89	0.90	0.92	0.93	0.94	0.96	0.97	0.99	1.0
Less value of franking credit	0.39	0.44	0.45	0.46	0.47	0.47	0.48	0.49	0.49	0.5
Unadjusted revenue allowance	8.90	11.88	11.99	12.09	12.20	12.30	12.40	12.50	12.60	12.69
Smoothed MAR	**8.90**	**11.88**	**11.99**	**12.09**	**12.19**	**12.29**	**12.40**	**12.50**	**12.61**	**12.72**

[1] This is for a nine month period, 1 October 2003 to 30 June 2004.

In arriving at its Decision, the Commission notes that its revenue cap is approximately 50 per cent lower than MTC's proposed revenue cap. The difference between MTC's proposed MAR and the MAR allowed by the Commission is largely the result of:

- a lower value for the regulatory asset base arising from the selection of an 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.

The table below illustrates the comparison between MTC's Application, the Commission's Preliminary View, and this Final Decision.

Comparison of Final Decision with Preliminary View and MTC's Application

		2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Opex	**MTC**	2.19	4.37	4.47	4.46	5.91	4.46	4.44	4.43	4.42	5.88	
	Pre	0.43	1.82	1.86	1.9	1.94	1.98	2.02	2.06	2.11	2.15	1.10
	Final	2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66	
Capex	**MTC**	0	0	0	0	0	0	0	0	0	0	
	Pre	0	0	0	10.26	0	0	0	0	0	0	0
	Final	0	0	0	0	0	0	0	0	0	0	
Return of capital	**MTC**	6.1	9.2	9.2	9.2	9.2	7.6	6.8	6.8	6.8	6.8	
	Pre	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
	Final	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65	
Return on capital	**MTC**	10.5	15.6	15.1	14.5	14	13.4	12.9	12.4	12	11.5	
	Pre	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03
	Final	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89	
Smoothed MAR	**MTC**	17.2	25.5	25.2	24.9	24.6	24.3	24	23.7	23.4	23.2	
	Pre	2.97	12.25	12.49	12.74	12.99	13.25	13.51	13.78	14.05	14.33	6.95
	Final	**8.90**	**11.88**	**11.99**	**12.09**	**12.19**	**12.29**	**12.40**	**12.50**	**12.61**	**12.72**	

[1] MTC's application and the Commission's Preliminary View were based on calendar years. The Commission's Final Decision is based on financial years.
MTC's figures for 2003 are for an six month period, 1 July 2003 to 31 December 2003
The Commission's Preliminary View for 2003 was for a three month period, 1 October 2003 to 31 December 2003
The Commission's Final Decision for 2003/04 is for a nine month period, 1 October 2003 to 30 June 2004

[2] In the Commission Preliminary View, it added half a year to the regulatory control period proposed by MTC to align MTC's regulatory control period with other TNSPs. This was for a 6 month period, 1 January 2013 to 30 June 2013.

The Commission notes that the revenue proposed in this decision is below the revenue proposed in its Preliminary View. This is due to a reduction in the opening asset value of Alternative 3, and therefore Murraylink's opening asset value, which leads to a reduction in the return of and return on capital figures; the deduction of the capex allowance granted by the Commission in its Preliminary View; and the variations in the cost of capital which largely reflect the prevailing market conditions/data at the time of this final decision. This has been partly offset by an increase in the opex allowance.

Service Standards

Based on advice from PB Associates and discussions with MTC, the Commission 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 1.97 per cent. The Commission's Preliminary View included a cumulative unavailability of 1.77 per cent.

Therefore, the Commission has adopted performance targets (see table below) to reflect some of the issues raised by MTC and comments made by PB Associates on these issues. The range of availability that will result in a financial incentive (rewards and penalties) is the same range that PB Associates recommended in its review of MTC's proposal.

Performance targets

Measure	Performance for maximum penalty (%)	Target performance (%)	Performance for maximum reward (%)	Weight (%)
Planned circuit energy availability	99.04	99.17	99.38	40
Forced outage circuit energy availability in peak periods	98.9	99.48	100	40
Forced outage circuit energy availability in off-peak periods	98.84	99.34	99.94	20

The Commission believes that these targets are achievable by MTC, especially the forced outage targets, given that Murraylink is a relatively new asset.

Commission's Decision

Summary

MTC has advised the Commission that, subject to consideration of this decision, it intends to terminate the classification of Murraylink's network service as a market network service.

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 and its alternative projects will deliver gross market benefits ranging from approximately $166 million to $347 million under most credible scenarios. The market simulations suggest the most credible range is between $170 million to $220 million.

Based on the ranking of the various alternative projects under the regulatory test assessment, the Commission considers that Alternative 3 satisfies the regulatory test in that it maximises the net present value of the benefit to the market having regard to its alternatives, timings and market development scenarios. The Commission will therefore use the cost of Alternative 3, $97.33 million, for the purposes of setting MTC's MAR.

The Commission will grant opex of $3 million (real) per annum, which is an opex totalling $32.71 million (nominal) over the regulatory control period. It will also allow a pass through for the following events:
- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

Timing

The Commission's determination will only come into operation once Murraylink's network service ceases to be classified as a market network service. If this does not occur by the date specified in paragraph 3 of the final determination set out below, this determination will lapse and will cease to have any effect. The Commission is of the view that MTC, having indicated its intention to convert Murraylink's network service to a prescribed service, should be required to do so as soon as reasonably possible after the Commission's determination is made.

This is subject to the qualification in paragraph 4 below. If there is an application for judicial review of this decision before Murraylink's network service ceases to be classified as a market network service, this determination would almost certainly lapse before the matter was finally resolved. This means that, even if the Commission's determination ultimately stands, it would have ceased to have effect and a fresh application would be required. To overcome this the Commission has decided that, if an application for judicial review of this decision is made before Murraylink's network service ceases to be classified as a market network service, this decision will not lapse until 28 days after that application is withdrawn, dismissed or otherwise discontinued. This means that, for example, if an application for review is dismissed, MTC will have 28 days to proceed with conversion. That part of the revenue cap that has not expired would apply for the remainder of the regulatory control period.

Commission's Final Determination

Under clause 2.5.2(c) of the Code, the Commission determines that, from the time Murraylink's network service ceases to be classified as a market network service:

1. **Murraylink's network service will be a prescribed service;**

2. **MTC will have a revenue cap for a regulatory control period ending on 30 June 2013. MTC's MAR under this revenue cap will be as follows:**

Financial year	**$ million (nominal)**
2003-04 (*year commencing 1 October 2003*)	**8.90**
2004-05	**11.88**
2005-06	**11.99**
2006-07	**12.09**
2007-08	**12.19**
2008-09	**12.29**
2009-10	**12.40**
2010-11	**12.50**
2011-12	**12.61**
2012-13	**12.72**

3. **Subject to paragraph 4 below, this determination will lapse if Murraylink's network service has not ceased to be classified as a market network service on or before Tuesday, 4 November 2003;**

4. **In the event that an application is made for judicial review of this determination before Murraylink's network service has ceased to be classified as a market network service, this determination will lapse 28 days after the day on which any such application is withdrawn, dismissed, or otherwise discontinued.**

1. 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 Australian Competition and Consumer Commission (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 the 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 the discretion to determine whether a market network service should be converted to a prescribed service and, adjust a revenue cap accordingly. Clause 2.5.2(c) states:

> 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 Murraylink Transmission Company (MTC), on behalf of Murraylink Transmission Partnership (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 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 (section 1.1);

- the review and public consultation processes followed by the Commission in reaching its decisions (section 1.2);
- an overview of the Murraylink transmission network (section 1.3); and
- the structure of this document (section 1.4).

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

The code does not set out specific criteria for conversion of an 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 (Saha) 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 Commission released its Preliminary View on 14 May 2003. The process that the Commission 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 looked to the relevant provisions and definitions contained in the code. The Commission noted that if the interconnector was determined to provide a prescribed service, it would set a regulatory asset value based on the option which maximises the net present value of the market benefits. The Commission was of the view that this would ensure that an MNSP will not accrue a material advantage by bypassing the provisions in Chapter 5 of the code. In response to the Commission's Preliminary View, the Commission received 15 submissions (Appendix B). The Commission still considers that the approach adopted in its Preliminary View in assessing MTC's conversion application is appropriate and consistent with clause 2.5.2(c) of the code, and the NECA Working Group's intention (see chapter 2 of this decision).

1.1.1 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) 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).

While typically a market network service that is converting will satisfy the first and second limbs of the Commission's working definition, the third 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.

1.1.2 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 believes that a converting MNSP should be made to 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. A copy of the regulatory test is provided in Appendix C.

1.1.3 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 *Statement of Principles for the Regulation of Transmission Revenue* (*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 Maximum Allowed Revenue (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:

$$\begin{aligned} MAR &= \text{return on capital + return of capital + opex + taxes} \\ &\quad \pm \text{service standards} \\ &= (WACC * WDV) + D + opex + taxes \pm \text{service standards} \end{aligned}$$

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	=	Commission 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.

1.2 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 Saha was engaged to review MTC's regulatory test application. Copies of the PB Associates and Saha 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 the Commission's Preliminary View.

- *The Commission released Preliminary View on 14 May 2003*: The Preliminary findings were that Murraylink could provide prescribed services. It also found that the cost of the option which maximises the present value of the market benefits was $114.42 million.

- *MTC requested a public forum.* A public forum was held in Adelaide on 8 July 2003. Interested parties presented submissions regarding the Commission's Preliminary View.

- *The Commission conducted further discussions with MTC and interested parties.*

- *The Commission made this Decision on 1 October 2003.*

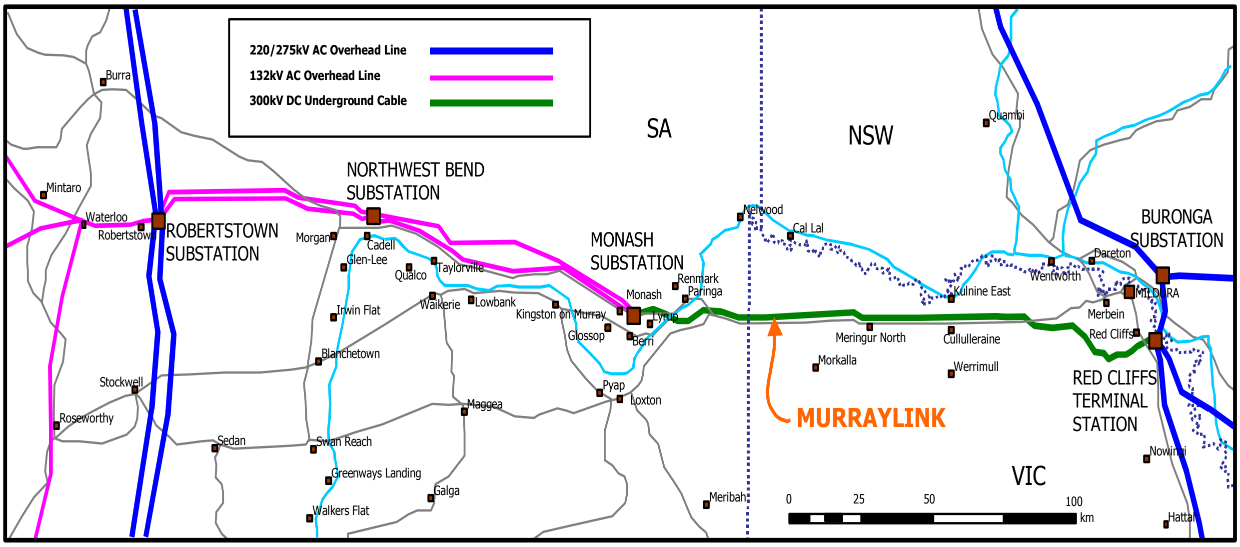
The Commission has taken into consideration issues raised by interested parties in submissions to its Issues Paper, Preliminary View, and submissions made at the Public Forum in this Decision.

1.3 Overview of the Murraylink transmission network

Murraylink is a privately funded electricity transmission asset 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 NEM transferring power between the Red Cliffs substation in Victoria and the Monash substation in South Australia. Murraylink currently has a rated capacity of 220 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 Power System AB of Sweden (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.

1.4 Structure of this document

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

- section 2 contains the Commission's assessment of MTC's conversion application using the process described in this introduction;
- section 3 discusses the asset valuation methodology adopted by the Commission in assessing MTC's regulatory asset value;
- section 4 sets out the Commission's regulatory test assessment. This includes:
  - an outline of the location and specification of the options considered under the regulatory test;
  - analysis of the power transfer capacity of Murraylink and its alternative options;
  - an assessment of the gross market benefits that Murraylink and its alternatives provide to the NEM under the regulatory test;
  - an assessment of the cost of Murraylink and the alternative projects; and
  - the ranking of the options considered under the credible market development scenarios and sensitivity analysis, and therefore the opening asset value of Murraylink resulting from the outcomes of the regulatory test.
- section 5 outlines the operating and maintenance expenditure (opex) for Murraylink;
- section 6 sets out the Commission's assessment of pass-through events for MTC;
- section 7 deals with MTC's weighted average cost of capital (WACC);
- section 8 sets out the Commission's assessment of each of the elements of the building block;
- section 9 sets out the service standards appropriate to the level of the revenue cap determined; and
- section 10 sets out a summary of the Commission's Decision, and the Commission's final determination.

2. Conversion of Murraylink to a prescribed service

2.1 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 that clause (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 in line with 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.

The remainder of this chapter summarises the Commission's decision concerning the conversion of Murraylink to a prescribed service, as well as the information considered by the Commission in arriving at its conclusions. This includes:

- a summary of the Commission's Preliminary View (section 2.2);
- a summary of submissions on the Preliminary View (2.3);
- the Commission's considerations on the conversion of Murraylink (section 2.4); and
- the Commission's conclusions (section 2.5).

2.2 Commission's Preliminary View

In its Preliminary View, the Commission recommended allowing conversion of Murraylink from a market network service to a prescribed service. In its assessment, the Commission focused on whether or not the service provided by Murraylink is a prescribed service. The approach adopted by the Commission was to determine whether Murraylink falls into the category of "prescribed service" as defined by the code. The Commission considered that this approach was consistent with clause 2.5.2(c) and the intention of the NECA Working Group.

In accordance with the relevant provisions of the code, the Commission found that Murraylink's services met the definition of a prescribed service and therefore proposed conversion of Murraylink from a market network service to a prescribed service.

2.3 Submissions on the Commission's Preliminary View

2.3.1 MTC's response to the Preliminary View

MTC states that the process adopted by the Commission for assessing MTC's conversion application is consistent with the intent of the NECA Working Group. MTC is of the view that the Commission has correctly concluded that Murraylink should be determined to be a prescribed service. Furthermore, it is MTC's view that the Commission is correct in its application of the regulatory test to ensure Murraylink constitutes an efficient investment and that MTC does not gain a commercial advantage of the Safe Harbour Provisions through bypass of clause 5.6.6 of the code or in its derived asset value.

2.3.2 Submissions from other interested parties

Conversion of Murraylink

The SA Minister for Energy believes that the Commission needs to give more consideration to the issue of whether Murraylink should be a prescribed service. The SA Minister for Energy and the NSW Minister for Energy submit that the Safe Harbour Provisions of the code are only intended as a safeguard against material changes in market structure or rules and should not be used to protect investors who make poor financial decisions. The SA Minister for Energy's view is that there has not been a material change in the market such that would warrant consideration of the Safe Harbour Provisions. Furthermore, the SA Minister for Energy is concerned about the precedent that this will set for other prospective MNSPs and the extent to which MNSPs that seek conversion via this process circumvent the usual scrutiny that proposed regulated interconnectors, such as SNI, are subject to.

According to ElectraNet, in the absence of any guidance in the code for exercising its discretion the Commission should have regard to the intent of the code provision as stated by the NECA Working Group. According to ElectraNet, the intent of the code provision was to ensure that investment is not inefficiently inhibited by non-commercial market design risks, nor should the conversion option shield the applicant from normal commercial risks.

TransGrid contends that the process proposed and used by the Commission in its Preliminary View for evaluating MTC's application for conversion does not support the main purposes of the transmission network planning regime in the code of promoting efficient transmission investment in the NEM. TransGrid is concerned that the process adopted in the Preliminary View sets the hurdle for conversion too low and this, in turn, will actually encourage inefficient investment in transmission. TransGrid believes that the conversion process should include a judgement as to whether or not there has been any material change in market design since the decision to invest was made, and a determination as to whether or not any such change has had a direct and material impact on the MNSP's commercial viability.

According to TransGrid, this is essential in order to align the conversion process to the intent of the Safe Harbour Provisions of the code being used to trigger the conversion process in the first instance. TransGrid submits that the Preliminary View has not identified why Murraylink's commercial viability has been affected by market design deficiencies that have become apparent since MTC made its investment decision. It adds that the Preliminary View also fails to identify changes in the market regulatory framework since MTC made its investment decision which have materially affected its commercial viability. The points raised by TransGrid are reiterated by NERA in an appendix to TransGrid's submission.

The NSW Minster for Energy states that there is no compelling reason for the Commission to allow Murraylink to earn a regulated income. Similar to the argument of TransGrid, it notes that there has been no change in the regulatory environment affecting the fortunes of unregulated interconnectors that were not able to be considered at the time that the investment was made.

In regards to the Safe Harbour provisions, ESIPC and ElectraNet are of the view that there has been no change in the market environment and that Murraylink's application is predicated on commercial rather than non-commercial risks. ESIPC, therefore, questions the applicability of the conversion provisions in the code. According to ESIPC, the low-threshold approach to allowing MNSPs to access the conversion provisions provides the opportunity, if not incentive, for future MNSP projects to game the market and distort the intent of the code.

Market definition

The NSW Minister for Energy disagrees with the Commission's view that SNI would not be a viable competitor to Murraylink. It questions whether sufficient actual or potential competition to Murraylink exists for the regulation of Murraylink to be unnecessary. It argues that the question the Commission is asking is whether Murraylink faces sufficient competition to not be regulated rather than whether Murraylink would be duplicated by another regulated interconnector if it converted to a prescribed service.

The NSW Minister for Energy adds that as SNI has been approved by both NEMMCO and the National Electricity Tribunal as maximising net benefits on the assumption that Murraylink is a "committed" unregulated interconnect project, it would thus most probably go ahead. It argues, therefore, that Murraylink as a non-prescribed service would likely face an effective competitor in a regulated SNI.

Incremental benefits of conversion

According to the NSW Government, conversion of Murraylink would only be justified if there are benefits to consumers which is only likely to happen if the asset value reflects the incremental benefits of the conversion. The NSW Government contends that the incremental benefits of conversion are likely to be small.

The NSW Government submits that an incremental benefits approach is more appropriate in determining the regulatory asset value. Using this approach, Murraylink would be valued at its expected return as an unregulated interconnect plus the market benefits arising from its conversion to a regulated service. In its submission the NSW Government cites various benefits of using the incremental benefits approach. For example, it ensures that the unregulated interconnect investor is at least as well off as before the conversion application. Also, according to the NSW Government, it minimises the competitive advantage that unregulated interconnects have over generators and demand-side management (DSM) projects. Under this approach, as an unregulated interconnect, Murraylink would be characterised as being part of the base case market development and as such, via the application of the test, would ensure that the remaining market participants are not adversely affected by the conversion of Murraylink.

Consistency between the Preliminary View and previous Commission decisions

In its submission to the Preliminary View, the NSW Government contends that the analysis supporting the Commission's decision to convert Murraylink to a prescribed service is inconsistent with the approach it has adopted in previous decisions. For example, the NSW Government claims that in its assessment of the Murraylink undertaking, the Commission argued that Murraylink was participating within the boundaries of a competitive market. The NSW Government argues that the Commission's analysis in the Preliminary View indicates that it no longer believes this to be the case.

2.4 Commission's considerations

2.4.1 Process for making 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. In its Preliminary View, the Commission outlined its understanding at that time of the requirements of clause 2.5.2(c). In particular, the Commission outlined its preliminary view that the Commission's ability to determine a service to be a prescribed service arises once an existing network service ceases to be classified as a market network service. On this basis, the Commission proposed to proceed by way of releasing a Position Paper setting out its position on MTC's conversion application and revenue cap, and issuing a formal determination once advised of the details of Murraylink ceasing to be classified as a market network service.

In finalising its views, the Commission has given further consideration to the requirements of clause 2.5.2(c) and the appropriate process for finalising the assessment of MTC's application. In particular, the Commission is concerned to ensure that its determination is properly coordinated with the requirements for Murraylink ceasing to be classified as a market network service. Further, the Commission is mindful that the processes ought to proceed smoothly within the technical requirements for the operation of the NEM. In this regard, the Commission has been advised by MTC that, subject to consideration of the Commission's decision, MTC's intention is to terminate the classification of Murraylink's network service as a market network service.

Consequently, the Commission has made its determination and set out its final position in this decision, rather than a prior position paper. However, in accordance with clause 2.5.2(c) the Commission's determination is expressed to not take effect until the existing service ceases to be classified as a market network service. The Commission has also set a time period within which this must occur.

2.4.2 Framework for whether a network 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." [3]

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

In its Preliminary View, the Commission indicated that the assessment of Murraylink's application involved a two step process: conversion and a revenue cap decision. The Commission further indicated that there is a threshold question of whether Murraylink should be converted to a prescribed service before any consideration could be given to the setting of it regulatory asset value. The Commission maintains that conversion applications should be assessed in accordance with 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's discretion. No express 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. Other issues raised in submissions in response to both the Issues Paper and the Preliminary View could be considered as part of the assessment of the conversion application. For example, whether an MNSP should demonstrate that the NEM has changed since its decision to construct a market network service, and the overall benefits to the public from conversion. These issues will be addressed below. However, notwithstanding the various issues raised in submissions, 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[4].

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 apparent intention 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 determined a regulatory asset value for Murraylink in the same way that the regulatory asset value for other new investments by TNSPs are determined. Therefore, by applying the regulatory test to converted network services an MNSP will not be able to bypass the provisions contained in Chapter 5 of the code. This will ensure that the regulated revenue

[4] Further discussion on the intent of the NECA working group is on p.22.

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 efficient transmission investment in the NEM.

Characterisation of 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 considers 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 the service provided by Murraylink satisfies 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:

- 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; and

- 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.

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 is defined by the ESC as describing a market that would be characterised by effective or potential competition.[5]

The ESC draws upon the Commission'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 2.1 sets out the criteria used by the ESC. The Commission has adopted such a framework and assessed Murraylink against these criteria. Table 2.1 provides the Commission's comments against each of the criteria. Overall, this assessment indicates that Murraylink would fall into the category of prescribed service.

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

Table 2.1 Criteria for assessing whether a market is characterised by effective competition

Criteria for effectively competitive market	Competition Concern	Comment
Number of competing providers	Yes	• Two interconnectors into South Australia, 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 South Australian 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.

As stated its the Preliminary View, 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.

For the foreseeable future, the Commission expects South Australia 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 minimum 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.

As noted previously, 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 rated capacity. Given the current market, it is unlikely 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 and provides substantial market benefits to the Riverland regions. This is discussed in chapter 4. In terms of competing providers, it would appear that none currently exist as Heywood is neither a competitor nor a substitute for Riverland support.

The NSW Minister for Energy argues that as SNI has been approved by both NEMMCO and the National Electricity Tribunal, it should be assumed that SNI will probably go ahead, and therefore Murraylink, as a non-prescribed service, would likely face an effective competitor in a regulated SNI. However, the Commission notes that the Victorian Supreme Court[6] subsequently set aside the Tribunal decision and has remitted the matter to the National Electricity Tribunal for reconsideration. The Commission therefore believes that there is still doubt as to whether SNI will proceed, notwithstanding the fact that the South Australian Government, NSW Government and TransGrid have appealed the Supreme Court's decision.

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 to the issues paper and Preliminary View, 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 regulatory asset value 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.[7] 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.

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[6] Murraylink Transmission Company Ltd vs NEMMCO & Ors [2003] VSC 265.
[7] The Electricity Supply Industry Planning Council, *Transmission system major augmentation review: Riverland Region Supply System, Review of Proposals, Recommendations*, July 2000.

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

As noted previously, 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 Part IIIA of the *Trade Practices Act 1974* (TPA)access regime. The 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 MTC's MAR.

One of the concerns raised in the submissions on both the Issues Paper and the Preliminary View is that the process adopted by the Commission for assessing MTC's conversion application is not consistent with the view of the NECA Working Group. The Commission acknowledges that 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 Commission believes that the process for assessing MTC's conversion application is consistent with the intent of the NECA Working Group. As foreshadowed by the NECA Working Group, the revenue entitlement for MTC will be based on its ongoing value to the market as a prescribed service.

A related concern raised in response to both the Issues Paper and the Preliminary View is that the conversion process enables an MNSP to receive a guaranteed revenue stream for a poor investment. As noted previously, the efficiency of Murraylink is handled through applying the regulatory test and its use in the determination of MTC's MAR. Accordingly, MTC's revenue is based on the need for the facility at the time of the application rather than the original capital cost. This methodology provides a safeguard against MNSPs receiving 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 the Murraylink service to operate as a prescribed service is likely to assist in meeting these conditions. 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:[8]

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 expected increased efficiency in the way that Murraylink would operate in the market will likely benefit electricity suppliers upstream and downstream of Murraylink, and consequently, all users of those services.

[8] 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.

Incremental benefits

Several submissions in response to both the Issues Paper and the Preliminary View 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.

2.4.3 Consistency between the Preliminary View and previous Commission decisions

There is a final issue arising from submissions in response to the Preliminary View that the Commission wishes to address. The NSW Minister for Energy argues that the analysis underpinning the Commission's decision to allow Murraylink to convert to a prescribed service is inconsistent with the approach adopted in previous Commission decisions. It argues that:

> "In its Preliminary View, the ACCC went to great lengths to demonstrate that Murraylink faces few potential competitors. However, if the ACCC believes Murraylink provides services that are not easily contestable, it is not clear why the ACCC previously allowed Murraylink to proceed as an unregulated interconnector without any conditions in the first instance …. The ACCC rejected imposing these conditions on Murraylink's Access Undertaking on the basis that Murraylink's conduct was sufficiently constrained by other market participants - that is, Murraylink was operating in the context of a competitive market." (P 6)

The Commission believes that its assessment of MTC's access undertaking highlighted market power issues, particularly concerning the ability of a generator in an importing region to withhold Murraylink's physical capacity to maintain interregional price differences. The draft decision therefore imposed a condition requiring disclosure of the identity of parties who contract with Murraylink for ownership of Murraylink's transmission property rights. This disclosure provision was designed to assist in detecting any potential breach of Part IV of the TPA. The access undertaking was not accepted until the disclosure provision was included.

The Commission's assessment of Murraylink's access undertaking, therefore, highlighted market power concerns and required an amendment to the undertaking to deal with these concerns. The Commission acknowledges, however, that the conditions placed on MTC’s access undertaking were not as stringent as those favoured by the New South Wales Government.

2.5 Conclusion

The Commission has considered MTC’s application, and the views of interested parties, and determines the service provided by Murraylink to be a prescribed service for the following reasons:

- the service satisfies the definition of a prescribed service;
- the Commission’s process for assessing conversion is consistent with the intention of the NECA Working Group as well as the Network Pricing and MNSP code changes; and
- the Commission’s approach ensures consistency, via the application of the regulatory test, between its consideration of MTC’s application for conversion and its approval of other forms of regulated investments.

Commission’s Decision

Under clause 2.5.2(c) of the code, the Commission determines that, from the time Murraylink’s network service ceases to be classified a prescribed service, Murraylink’s network service will be a prescribed service. Therefore, the Commission will determine a MAR for Murraylink’s network service in accordance with Chapter 6 of the code.

3. Asset Valuation methodology

3.1 Introduction

Clause 2.5.2(c) provides that, if a network service that ceases to be classified as a market service is classified as a prescribed service, the revenue cap for the relevant NSP may be adjusted in accordance with Chapter 6 of the code to include, to an appropriate extent, the relevant network elements that provide those network services.

One of the first steps in setting a revenue cap for MTC is to identify the methodology that will be used to determine MTC's regulatory asset value. This chapter considers which methodology is appropriate for valuing MTC's asset base.

The remainder of this chapter:

- sets out MTC's application (section 3.2);
- summarises the Commission's Preliminary View (section 3.3);
- summarises submissions by MTC and interested parties in response to the Commission's Preliminary View (section 3.4);
- sets out the Commission's approach to valuing MTC's opening asset value (section 3.5); and
- sets out the Commission's conclusion (section 3.6).

3.2 MTC's application

MTC[9] proposes an asset valuation methodology which it summarised at pages iv to v as follows:

- Define the Prescribed Service

While an interconnector might assist TNSPs to meet the technical requirements of Schedule 5.1 of the Code, an interconnector can also deliver more sophisticated technical services, such as inter-regional transfer capacity.

- Calculate the Gross Market Benefits

Using appropriate modelling tools, the gross market benefits of the existing interconnector can be determined.

- Select the Alternative Projects

MTC noted that an independent assessment needs to be made of the several ways in which the electricity system could be notionally reconfigured to provide the same

[9] *Application for conversion to a Prescribed Service and a Maximum Allowable Revenue for 2003-12*, MTC, 18 October 2002.

prescribed service as the existing interconnector. Notional reconfigurations take the form of alternative projects.

- Estimate the Cost of the Alternative Projects

MTC notes that the full life-cycle cost of each alternative project needs to be determined as the present value of its capital and opex costs. Furthermore, MTC notes that there is a range of uncertainties associated with the costs and timing of each of the alternative projects. For example, there is considerable uncertainty associated with the environmental and easement costs and constraints of constructing overhead transmission lines. MTC states that as the regulatory valuation approach is designed to assess the actual costs that a potential new entrant would experience, an analytical framework needs to be applied that enables the relative risks associated with alternative projects to be taken properly into account.

- Determine the Regulatory Cost for Interconnector

MTC states that the regulatory cost for an interconnector is the sum of its regulatory asset value and the net present value of its future operating and maintenance costs.

For an interconnector to satisfy the regulatory test, its regulatory cost must be less than or equal to, the lesser of:

- the value of the gross market benefits the interconnector provides;
- the full life-cycle cost of the lowest cost alternative project; and
- the estimated life-cycle cost of the existing interconnector itself.

In this way, MTC notes that the regulatory cost of the interconnector is set such that the interconnector would provide a positive net market benefit that is greater than or equal to any of the net market benefits provided by any of the alternative projects selected, and no greater than the actual cost of the interconnector. Thus the interconnector would pass the regulatory test.

- Determine the initial regulatory asset value

MTC states that the regulatory asset value of the interconnector is equal to its regulatory cost minus the net present value of its future on-going operating and maintenance costs.

MTC submits that, using this methodology, the initial regulatory asset value of Murraylink is $176.906 million, being the gross market benefits provided by Murraylink ($214.24 million) minus the NPV of Murraylink's future opex costs ($37.334 million).[10]

[10] Application, paragraph 4.9.

3.3 Commission's Preliminary View

In its Preliminary View, the Commission stated that its 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 was 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 Commission noted that 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 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.

The Commission also noted that 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 was of the view that, in the absence of specific criteria under clause 2.5.2(c), that it was 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. In its Preliminary View the Commission determined that Murraylink is eligible to be classified as a prescribed service. The Commission believed that it was appropriate to apply the regulatory test in order to assess whether Murraylink delivers net benefits to the market. This process ensured 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.

Therefore, in its Preliminary View, the Commission used the regulatory test to determine the asset base for Murraylink by reference to the cost and configuration of the alternative that was found to maximise the net present value of the market benefit. In applying the regulatory test, the Commission took the view that its analysis should not be limited to projects that provide the exact same level of technical service as Murraylink. The Commission felt that it would be more appropriate to be guided by what delivers the highest net benefits to the market.[11]

[11] Preliminary View, p 55.

3.4 Submissions on the Commission's Preliminary View

3.4.1 MTC's response to the Preliminary View

In response to the Commission's Preliminary View, MTC made two submissions setting out the reasons why it does not agree with the Commission's use of the regulatory test to establish an asset base for Murraylink.[12]

MTC submits that the code, specifically clause 2.5.2(c) requires that any adjustment to its revenue cap is to be in accordance with Chapter 6 of the code. It notes that the Commission must comply with Part B of Chapter 6 and apply the *Draft Regulatory Principle*, which represents how the Commission will implement its obligations under Chapter 6.

MTC notes that the *Draft Regulatory Principles* states that the Commission's regulatory valuation of transmission assets will be based upon an ODRC[13] principle and sets out the Commission's interpretation of this principle.

MTC submits that the Commission has not applied an asset valuation methodology to Murraylink that is consistent with the Commission's previous approach to ODRC. It notes that the Commission has taken into account alternative projects that would provide different levels of service delivery than Murraylink, and the Commission has proposed to value Murraylink in a manner that is not consistent and more onerous than the manner in which it values all other new and existing transmission assets in the NEM. MTC reiterates that its valuation methodology set out in its application takes account of alternative projects that would be called upon to provide same level of service delivery as Murraylink, and is consistent with the Commission's currently defined ODRC valuation.

MTC further outlines three different asset valuation methodologies:

Conventional ODRC

MTC notes that this can be defined as:

- defining the service delivery in terms of the power transfer capability that the existing asset is being called upon to deliver; and
- determining the regulatory value of the asset on the basis of the estimated capital cost of the optimally configured alternative project

It notes that this does not involve an assessment of an asset's economic value and that the optimally configured alternative project should be:

- Located at the same location as the asset being valued;

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[12] *Submission in response to Preliminary View*, MTC, 18 July 2003, p 6; *Submission on Stakeholder comments on the Preliminary View*, MTC, 12 August 2003, p 16-19.
[13] Other Commission documents, including the Draft Regulatory Principles, described this methodology as "Depreciated Optimised Replacement Cost" or "DORC". For the purposes of this Decision, the terms "DORC" and "ODRC" are interchangeable.

- Capable of providing the same transfer capability that the asset being valued will be called upon to provide; and
- Practical from a technical, operational, environmental and community acceptance point of view.

Extended ODRC

MTC submits that this can be defined as:

- defining the service delivery in terms of the power transfer capability that the existing asset is being called upon to deliver;
- Determining the regulatory cost as the lessor of:
  - the NPV of the estimated capital and opex cost of the optimally configured depreciated alternative project; and
  - the asset's expected gross market benefits over its remaining life
  - the sum of the actual capital cost and the NPV of the opex of the depreciated asset.

It notes that this does not involve an assessment of an asset’s economic value and that the optimally configured alternative project should be:

- Located at the same location as the asset being valued;
- Capable of providing the same transfer capability that the asset being valued will be called upon to provide; and
- Practical from a technical, operational, environmental and community acceptance point of view.

Regulatory test

MTC notes that this can be defined as:

- Identification of alternative projects that may provide a range of different levels of service and different streams of costs and benefits to the asset being valued;
- The alternative project that provides the highest expected net market benefit is deemed to pass the regulatory test (and if no alternative provides a positive net market benefit then no alternative passes the regulatory test); and
- Determining the regulatory asset value of the existing asset such that the asset would provide the same level of net market benefit as the alternative.

Further, it notes that to the extent that alternative projects chosen with levels of service delivery similar to the asset being valued, the conventional ODRC asset valuation methodology and the regulatory test asset valuation methodology are to some degree similar. The main difference between the two ODRC valuation methodologies and the regulatory test valuation methodology is the breadth of alternative projects that could be considered, and the role of 'net market benefits' with respect to the regulatory value assigned to an asset

MTC submits that the extended ODRC valuation methodology provides the most appropriate means by which the Commission can value Murraylink in a manner that is:

- appropriate regard to the regulatory test;
- applies a deprival valuation approach in accordance with chapter 6 of the code and the Commission's *Draft Regulatory Principles*;
- is consistent with the Commission stated intentions that MTC's application for regulated revenue will be determined in the same manner in which the Commission determines revenue caps for all other new and existing transmission assets; and
- does not face the significant practical implementation challenges of the regulatory test approach.

3.4.2 Submission by other interested parties

Consistency between conversion and Chapter 5

The SA Minister for Energy and ESIPC raise concerns that the Commission's current interpretation of the code with respect to converting a market network service to a prescribed service enables MNSPs to by pass the regulatory test under Chapter 5 of the code, which other proposed regulated interconnectors are subject to. ESIPC notes that it would appear open for MNSPs to identify emerging requirements for interconnector and install a market network service earlier than normal market indicators, and gain a preferred market position.

ODRC valuation and alternatives

NERA notes that the regulatory test analysis will only give an equivalent asset valuation to an ODRC analysis if the alternative projects considered are those which provide a similar level of service, rather than restricting alternatives to providing an equivalent level of service. NERA further notes that ACG, on behalf of Murraylink, incorrectly claims that optimisation carried out under an ODRC valuation does not commonly consider different levels of service. NERA states that an ODRC valuation would consider alternative technologies to ensure that the choice of technology adopted was appropriate, and was not 'gold plating'.

Cost of alternatives above gross market benefits

NERA and MTC notes that it is not clear what regulatory asset value would apply if the cost of alternative projects were above the gross market benefits of the market network service provider, and notes that the Commission should set out its intended approach.

3.5 Commission's considerations

3.5.1 Requirements of the Code

Clause 2.5.2(c) requires the Commission to set a revenue cap for the relevant Network Service Provider "in accordance with Chapter 6". The provisions governing the regulation of transmission revenue are set out in Part B of Chapter 6 (clause 6.2). Clause 6.2.4(a) provides that economic regulation is to be of the CPI-X form (or some incentive based variant). Clause 6.2.4(b) provides that, in applying this form of economic regulation, the Commission must set a revenue cap for each TNO and/or TNSP (whichever is appropriate) for a regulatory control period of not less than 5 years. Clause 6.2.4(f) provides that revenue caps 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.

This means that, if the Commission classifies Murraylink as a prescribed service under clause 2.5.2(c), clause 6.2.4 requires it to set a revenue cap for MTC (as the TNSP) for a period of not less than 5 years. Clause 6.2.4(c) provides that, in setting a revenue cap for a TNSP, the Commission must take into account the revenue requirements of the TNSP having regard to, among other things:

> "(5) the provision of a fair and reasonable risk-adjusted cash flow rate of return on efficient investment including sunk assets subject to the provisions of clause 6.2.3(d)(4)".

Clause 6.2.3 sets out the principles that are applicable to the regime under which the Commission regulates transmission revenues. Clause 6.2.3(d)(4) provides that:

> "The regulatory regime to be administered by the ACCC must be consistent with the objectives outlined in clause 6.2.2 and must also have regard to the need to:
>
> ...
>
> (4) provide a fair and reasonable risk-adjusted cash flow rate of return to Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) on efficient investment given efficient operating and maintenance practices on the part of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) where:
>
> (i) assets created at any time under a take or pay contract are valued in a manner consistent with the provisions of that contract;
>
> (ii) assets created at any time under a network augmentation determination made by NEMMCO under clause 5.6.5 are valued in a manner which is consistent with that determination;
>
> (iii) subject to clauses 6.2.3(d)(4)(i) and (ii), assets (also known as "sunk assets") in existence and generally in service on 1 July 1999 are valued at the value determined by the Jurisdictional Regulator or consistent with the regulatory asset base established in the participating jurisdiction provided that the value of these existing assets must not exceed the deprival value of the assets and the ACCC may require the opening asset values to be independently verified through a process agreed to by the National Competition Commission;
>
> (iv) subject to clauses 6.2.3(d)(4)(i) and (ii), valuation of assets brought into service after 1 July 1999 ("new assets"), any subsequent revaluation of any new assets and any subsequent revaluation of assets existing and generally in service on 1 July 1999 is to be undertaken on a basis to be determined by the ACCC and in determining the basis of asset valuation to be used, the ACCC must have regard to:
>
> A the agreement of the Council of Australian Governments of 19 August 1994, that deprival value should be the preferred approach to valuing network assets;
>
> B any subsequent decisions of the Council of Australian Governments; and

C such other matters reasonably required to ensure consistency with the objectives specified in clause 6.2.2; and

(v) benchmark returns to be established by the ACCC are to be consistent with the method of valuation of new assets and revaluation, if any, of existing assets and consistent with achievement of a commercial economic return on efficient investment".

The assets that constitute Murraylink are "new assets" within the meaning of clause 6.2.3(d)(4)(iv) (ie. assets brought into service after 1 July 1999). This means that the valuation of these assets is to be undertaken on a basis to be determined by the Commission, having regard to the matters in clause 6.2.3(d)(4)(iv)(A) to (C).

Clause 6.2.3(d)(4)(iv)(A) requires the Commission to have regard to COAG's 1994 agreement that deprival value should be the preferred approach to valuing network assets. "Deprival value" is defined in Chapter 10 of the code as:

> "A value ascribed to assets which is the lower of economic value or optimised depreciated replacement value."[14]

Clause 6.2.3(d)(4)(iv)(C) requires the Commission to have regard to such other matters reasonably required to ensure consistency with the objectives in clause 6.2.2. These objectives are as follows:

> "The transmission revenue regulatory regime to be administered by the ACCC pursuant to this Code must seek to achieve the following outcomes:
>
> (a) an efficient and cost-effective regulatory environment;
>
> (b) an incentive-based regulatory regime which:
>
> (1) provides an equitable allocation between Transmission Network Users and Transmission Network Owners and/or Transmission Network Service Providers (as appropriate) of efficiency gains reasonably expected by the ACCC to be achievable by the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate); and
>
> (2) provides for, on a prospective basis, 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 of the Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);
>
> (c) prevention of monopoly rent extraction by Transmission Network Owners and/or Transmission Network Service Providers (as appropriate);
>
> (d) an environment which fosters an efficient level of investment within the transmission sector, and upstream and downstream of the transmission sector;
>
> (e) an environment which fosters efficient operating and maintenance practices within the transmission sector;
>
> (f) an environment which fosters efficient use of existing infrastructure;
>
> (g) reasonable recognition of pre-existing policies of governments regarding transmission asset values, revenue paths and prices;

[14] Neither "economic value" nor "optimised depreciated replacement value" are defined in the code.

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

(i) reasonable regulatory accountability through transparency and public disclosure of regulatory processes and the basis of regulatory decisions;

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

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

The Commission has also published a *Draft Regulatory Principles*[15] that explains in greater detail how it proposes to regulate transmission revenues in accordance with Chapter 6 of the code. The Commission notes that it is currently in the process of finalising the *Draft Regulatory Principles*. The Commission released its Discussion Paper as part of this review on 28 August 2003.

In chapters 4 and 5 of the *Draft Regulatory Principles* the Commission states that its preferred asset valuation methodology is to use an ODRC valuation. In determining the deprival value of an asset, ODRC is preferred to a methodology based on economic value because economic value involves a degree of circularity (ie. the economic value of an asset is the net present value of the expected future cash flows generated by that asset. However, these expected future cash flows are determined by the regulator).

It is important to note that the *Draft Regulatory Principles* pre-dates clause 2.5.2(c) of the code and the provisions of the code which allow for the operation of a market network service. At the time the *Draft Regulatory Principles* was written the Commission was not in a position to consider the proper approach to asset valuation where a market network service is re-classified as a prescribed service. Accordingly, the Commission has sought input from stakeholders on this issue through the publication of the Issues Paper and the Preliminary View.

3.5.2 Possible asset valuation methodologies

Three possible asset valuation methodologies have emerged from MTC's submissions and the Commission's Preliminary View.

ODRC (described by MTC as "conventional ODRC")

At page 42 of the *Draft Regulatory Principles* the Commission described the ODRC methodology as follows:

"The determination of a valuation for transmission system assets on the basis of DORC involves three stages. The standard approach has been for these steps to comprise:

[15] *Draft Statement of Principles for the Regulation of Transmission Revenues*, ACCC, 27 May 1999.

- Optimisation – determine the optimal configuration and sizing of transmission assets;
- Replacement costs – a modern engineering equivalent (MEE) is established for each asset in the optimised system and a standard replacement cost (SRC) established; and
- Depreciate those assets (usually straight line) using the standard economic life (SEL) of each asset together with an estimate of the remaining life (RL) of each asset. For example, if the standard economic life of an asset is 40 years and its remaining life is 10 years, the asset would be depreciated to 25 per cent of the replacement cost of the MEE."

On the subject of optimisation, the Commission stated (at page 43):

> "Discretion is available in deciding how the optimal system configuration should be determined. Even in the absence of alternative technologies there is an issue as to what level optimisation should be considered and whether it should be done in respect of each item of infrastructure or on a system-wide basis. There is clearly an important trade-off involved in the level of detail considered and the cost of conducting the evaluation. The concept of a MEE for identifiable segments or modules of infrastructure is a practical application of this trade-off. For the most part it is expected that technological change will manifest itself through incremental reductions in the cost of MEEs.
>
> Generally, a top-down approach, which considers infrastructure from a system–wide perspective is important since it allows major differences from existing infrastructure to be quickly identified. Moreover, the top-down approach can more readily accommodate the impact of new or alternative technologies. For example, an optimal solution may do away with existing types of infrastructure and may involve a totally different transport mechanism or product to satisfy associated final demand in end markets. Such solutions may only be apparent when the customer base and services provided are considered in the broadest possible perspective."

In its response to submissions on the Preliminary View, MTC submits that the Commission had, in previous regulatory decisions for transmission networks, applied what MTC described as a "conventional ODRC" methodology, based on reports by consultants engaged by TNSPs and the Commission for the Victorian, South Australian and Queensland revenue cap determinations.

ODRC was a relevant factor in the determination of revenue caps for existing transmission networks in New South Wales and the ACT, Queensland, South Australia and Victoria (and will be in relation to Tasmania). However, it is important to note that, in determining the opening asset value of these networks, the Commission's discretion was limited by clause 6.2.3(d)(4)(iii) of the code. Since the vast majority of the assets which comprised these networks were "sunk assets",[16] the code required these asset to be valued at the value determined by the jurisdictional regulator or consistent with the regulatory asset base established in the jurisdiction, provided that their value did not exceed deprival value.[17] ODRC was relevant to this exercise, in that clause 6.2.3(d)(4)(iii) empowered the Commission to have the jurisdictional value verified through a process agreed to by the National Competition Council. However, no such exercise was ever undertaken.

[16] clause 6.2.3(d)(4)(iii) defines "sunk assets" as assets in existence and generally in service on 1 July 1999 (although in Victoria the relevant date was 1 January 2001 – see clause 9.8.3(a)(1)).
[17] ie. the lesser of ODRC and economic value.

Regulatory test

As discussed above, in the Preliminary View the Commission valued Murraylink in accordance with the regulatory test, that is, it ascribed to Murraylink an asset value that reflected the value of the cost of the alternative that maximised the net present value of the benefits to the market.

Extended ODRC

MTC has proposed a valuation methodology which it submits is based on a conventional ODRC methodology in which "service delivery" is defined in terms of the power transfer capability that the existing asset is being called upon to provide for the purposes of identifying the optimally configured alternative project.

MTC's methodology varies from the "conventional ODRC" methodology in that:

- the regulatory cost of the asset is assessed as the lesser of:
    - the net present value of the estimated capital and opex costs of the optimally configured depreciated alternative project;
    - the assets' expected gross market benefits over its remaining life; and
    - the sum of the actual capital cost and the net present value of the opex costs of the depreciated asset; and
- the regulatory asset value would be capped at the value of its expected gross market benefits less the NPV of its life cycle opex costs (the asset's "economic value").

MTC submits that this method has appropriate regard to the regulatory test in that:

(a) the cost of Murraylink upon conversion will not exceed the expected benefits it will provide to the market; and

(b) if an alternative project can be identified that:

- is capable of providing the same service as the existing asset is being called upon to provide; and
- is estimated to have a lower combined capital and opex costs than the expected gross market benefits of the existing asset;

then the regulatory cost of the existing asset will be such that it will provide a net market benefit.

3.5.3 Treatment of new and existing assets under the Code

The Commission adopted ODRC in the *Draft Regulatory Principle* because it determined that it is a methodology that is consistent with the requirements of Part B of Chapter 6 of the code. However, given that the *Draft Regulatory Principle* pre-dates clause 2.5.2(c) of the code, the Commission did not consider whether it is the best methodology to determine the asset base of a network that has been classified as a prescribed service under clause 2.5.2(c). The Commission did discuss this issue at page 138 of its determination authorising amendments to the code that included clause 2.5.2(c).[18]

> "Interested parties raise the issue of such a process enabling MNSPs to bypass the regulatory test that applies to new prescribed network services such as interconnectors, augmentations or augmentation options. The process for establishing a new market network service is seen by some interested parties as administratively more simple than the process for establishing a new regulated interconnector. The key concern appears to be that conversion from market to prescribed network services offers an administratively simple path to construct network services, which could then be allocated a regulated revenue stream, rather than remaining subject to market risks.
>
> Clause 2.5.2(c) sets out an arrangement where the relevant regulator has a high degree of discretion regarding the classification of a network service as a prescribed service and determining the appropriate extent that a revenue cap or price cap is adjusted to reflect the newly prescribed services.
>
> The Commission considers that as the nominated regulator for transmission assets, the Commission will generally be the relevant regulator exercising its discretion in regard to conversion of market network service to prescribed network services. Where the Commission decides a network service may be a prescribed network service, an NSP will require a revenue stream to be determined for that service. The Commission will consider the prudence of the network service at the time the conversion to a prescribed service occurs, rather than consider any earlier investment decisions. As such the investor would bear the risk of the Commission optimising down the value of the assets - with the consequence of reduced revenue streams, at the time it converted to regulated status and at each regulatory review into the future.
>
> The Commission considers many of the concerns raised by interested parties can be addressed by the Commission's *Draft Regulatory Principles.*
>
> The Commission will consider any applications to convert from market to prescribed status on a case by case basis. However, the *Draft Regulatory Principles* clearly set out the process that incumbent NSPs must follow at each regulatory review and applicants for conversion of network services to prescribed status will have to follow the same process. The Commission will develop the *Draft Regulatory Principles* to set out the process and guidelines needed to formalise the conversion arrangements.
>
> Further the *Draft Regulatory Principles* set out that a DORC valuation will be used to value (or revalue) the asset base of the NSP. The Commission considers that the DORC valuation allows for consideration of all possible options for replacing existing network services, as well as consideration of current and future utilisation rates. The effect of a DORC valuation will be that the network is valued to reflect the least cost solution to resolve any demand and supply imbalance needing to be addressed. Thus the process of changing status of network services requires the NSP to submit to a valuation process that delivers outcomes consistent with the intent of the regulatory test. The processes set out in the *Draft Regulatory Principles* may be simpler than the regulatory test processes but the Commission considers that no material advantage will accrue to NSPs converting from market to prescribed status through bypass of the regulatory test."

In this decision the Commission noted concerns that the possibility of converting a market network service to a prescribed service could enable a network service provider to by-pass the regulatory test under Chapter 5 of the code. Similar concerns

[18] *Applications for Authorisation, Amendments to the National Electricity Code, Network Pricing and Market Network Service Providers*, Determination, ACCC, 21 December 2001.

have been put to the Commission during the consultation process relating to MTC's Application[19] and in submissions to the Preliminary View.

In the Commission's authorisation determination, it foreshadowed the possibility of using an ODRC valuation after conversion on the basis that this will produce an outcome consistent with the intent of the regulatory test. However, while the Commission still considers that the use of ODRC will produce an outcome that is consistent with the object of regulatory test (and vice versa) it will not necessarily produce an outcome that is the same, in that it may not allow for consideration of the same range of options for replacing existing network services as would be allowed under the regulatory test.

The difference between the regulatory test and ODRC

The Commission does not consider the difference between an ODRC valuation and the regulatory test to be significant. Both methodologies seek to identify and evaluate the optimal configuration and sizing of transmission assets in order to achieve a particular level of service. The only potential difference between the two is that the regulatory test may require the consideration of a wider range of alternatives that assume different levels of service.

Clause 5.6.6(b) of the code requires applicants seeking to establish a new large network asset to rank the proposed new asset and all "reasonable network and non-network alternatives" in accordance with the principles contained in the regulatory test. What is a "reasonable" alternative is not the subject of an exhaustive definition. However, clause 5.6.6(b)(1)(iii) provides that it includes (but is not limited to) interconnectors, generation options, demand side options, market network service options and options involving other transmission and distribution networks.

The former clause 5.6.6(k)(1) required consideration of "practicable" alternatives. The Supreme Court of Victoria endorsed the approach of the National Electricity Tribunal in considering a "practicable alternative" to be an alternative that is relevantly substitutable (in the sense that it produced a result "similar to" the proposed interconnector).[20]

Neither the current code (which requires consideration of "reasonable" alternatives) nor the former code (which required consideration of "practicable" alternatives, being alternatives that produce a similar result) limits the application of the regulatory test to alternatives that deliver the same service as the existing asset (in terms of having the same power transfer capability or the exact same level of technical service).

Similarly, the Commission's statements on optimisation at page 43 of the *Draft Regulatory Principles* (reproduced above) do not appear to import such a limitation into an ODRC valuation. The Commission has not stated that, in seeking to determine the optimal size and configuration of a network for the purposes of an

[19] eg. n/e/r/a (report submitted by TransGrid), January 2003, p 12); Ergon Energy, 28 February 2003, p 2; ESIPC, 28 February 2003, p 8; Santos, 28 February 2003; ElectraNet SA, March 2003, p 5, 7; Energy User's Association of Victoria, 3 April 2003, p 4.
[20] *Murraylink Transmission Company v NEMMCO & Ors*, [2003] VSC 265, para 24. Clause 5.6.6(k)(1) was repealed and replaced by the current version of cl 5.6.6 in March 2002.

ODRC valuation, it would necessarily limit itself to an alternative network that was located in the same place as the existing network and which had the same transfer capacity. It is possible that the Commission would want to have regard to the future needs of the market in determining the optimal size and configuration of a replacement asset. It should also be noted that the Commission has received conflicting submissions on whether an ODRC valuation is limited to the consideration of alternatives that will provide the same level of service.[21]

However, it could be argued (as MTC has done) that an ODRC valuation methodology does not normally involve optimisation based on alternatives that might supply a different level of service. If this argument was accepted, it creates the possibility that an ODRC valuation and the regulatory test, while generally consistent, could produce a different outcome, in that the regulatory test is arguably more explicit in requiring consideration of a range of alternatives that provide a similar, although not necessarily identical, level of service.

The difference between the regulatory test and extended ODRC

Similarly, the Commission is not convinced that the extended ODRC methodology proposed by MTC would produce an outcome that it is consistent with the regulatory test. The central requirement of the regulatory test is to determine whether a proposal maximises net market benefit. Used in this case, the regulatory test will produce an asset value for Murraylink that reflects the cost of the alternative that maximises the net present value of the market benefit.

While MTC's extended ODRC methodology might produce an outcome whereby the regulatory asset value for Murraylink does not exceed its gross market benefits, it would not necessarily produce a value for Murraylink that is consistent with maximising the net present value of the market benefit, as it does not take into account the range of alternatives that would be considered under the regulatory test. MTC submits that its methodology would produce an asset value that equates to the value of an asset which is capable of providing the same service as Murraylink and has a lower cost than Murraylink. However, the regulatory test would give preference to a reasonable alternative that might provide a different service, but a greater net market benefit.

The need for consistency of treatment between new and existing assets

The potential for an ODRC or extended ODRC methodology to produce an outcome that is different to regulatory test leaves open the risk that a network service provider could use the conversion process in clause 2.5.2(c) to by-pass the provisions of the code that would ordinarily be applicable to the construction of a new interconnector.

There are two ways in which a person can obtain approval under the code to establish a new interconnector:

[21] eg. TransGrid's submission of 18 July 2003 included a report by n/e/r/a which argues that an ODRC valuation would consider similar rather than equivalent levels of service (page 7). The January 2003 report by Saha, at p 74, notes that the issue of optimisation, particularly with regard to the scope of alternatives, is a matter of on-going debate.

1. Seek approval under Chapter 5 to construct a new network asset

An interconnector that has an estimated total capitalised expenditure in excess of $10 million is classified under the code as a "new large network asset".[22] Clause 5.6.6 of the code provides for a TNSP to publish an application to construct a new large network asset. This application must include a description of all reasonable network and non-network alternatives, a ranking of the proposed new large network asset and all reasonable alternatives in accordance with the regulatory test, and an analysis of why the proposed new large network asset satisfies the regulatory test. Various aspects of this analysis can be appealed to a Dispute Resolution Panel under Chapter 8 of the code (see clause 5.6.6(h)) or the Commission (see clause 5.6.6(l) and (m)).

Clause 5.6.6 is silent on whether a new large network asset that satisfies the regulatory test is to be automatically rolled into the TNSP's asset base at the re-set of its revenue cap. This is a matter that the Commission must determine under the principles in clause 6.2 discussed above. However, at the very least, the Commission would be expected to give significant weight to the fact that the asset had satisfied the regulatory test.

2. Construct a market network service

The pre-conditions for the establishment of a market network service are set out in clause 2.5.2(a). A person seeking to establish a market network service is not required to make an application under clause 5.6.6 (ie. they are not required to demonstrate that the proposed interconnector satisfies the regulatory test). However, a market network service is not a prescribed service and a MNSP is not entitled to impose charges under Chapter 6 of the code (clause 2.5.2(b)). This means that the market network service cannot be rolled into an asset base for the purposes of determining a revenue cap under Chapter 6 for the network service provider.

If an interconnector is established as a market network service and subsequently converted to a prescribed service under clause 2.5.2(c), the use of an ODRC valuation methodology to determine an asset base under Chapter 6 might result in the network service provider obtaining a higher revenue cap than it would have had it sought approval to establish a new large network asset under clause 5.6.6. If the interconnector had been assessed under clause 5.6.6 at a value arrived at using an ODRC valuation, it is possible that the interconnector might not have satisfied the regulatory test on the basis that there was an alternative that delivered a greater net market benefit.

Clause 1.3(b)(4) provides that one of the objectives of the market is that:

> "a person wishing to enter the market should not be treated more favourably or less favourably than if that person were already participating in the market".

The possibility of the outcome described above would defeat this objective, in that a MNSP could be able to achieve a better result due to the fact that it was already participating in the market as a MNSP.

[22] An interconnector that has an estimated total capitalised expenditure between $1 million and $10 million is classified under the code as a "new small network asset".

The Commission is of the view that the most effective way to ensure consistent treatment between a person seeking to construct a new large network asset to supply a prescribed service and a network service provider seeking to convert a market network service to a prescribed service is to apply the same test in determining the asset base for that prescribed service, namely the regulatory test.

3.5.4 Consistency with Chapter 6 of the Code

The Commission recognises that the asset valuation methodology it proposes to use to set an asset base for Murraylink must satisfy the requirements of Chapter 6 of the code. The primary purpose the regulatory test is to determine whether a proposed new asset should be approved under Chapter 5 of the code, which is concerned with network connection. Accordingly, the regulatory test establishes criteria that are based on maximising the net present value of the benefit to the market (ie. maximising benefits relative to costs).

However, since it may be expected that assets which are approved under the regulatory test will be rolled into the asset base of a TNSP under Chapter 6, it is necessary that the regulatory test be consistent with the method in which the Commission would value assets under Chapter 6 of the code. This is reflected in clause 5.6.6(q) of the code (as it was prior to March 2002). This clause stated that:

> "The ACCC must:
>
> (1) promulgate the regulatory test (and may vary the regulatory test from time to time);
>
> (2) have regard to the need to ensure that the regulatory test is consistent with the basis of asset valuation determined by the ACCC for the purposes of clause 6.2.3."[23]

At pages 39 to 41 of the *Draft Regulatory Principles* the Commission explains why it considers ODRC to be the most appropriate asset valuation methodology for the purposes of chapter 6 of the code and, in particular, the objectives in clause 6.2.2. The Commission is of the view that the use of the regulatory test to determine an asset base in this case meets the objectives in clause 6.2.2 for the same reason. As discussed above, the principle difference between ODRC and the regulatory test is that the regulatory test arguably requires consideration of a wider range of options having regard to different levels of service. However, the regulatory test still seeks to determine a value based on the optimal configuration and sizing of the asset.

The use of the regulatory test also has regard to COAG's preference that deprival value be the preferred approach for asset valuation. While clause 6.2.3(d)(4)(iv)(A) does not prescribe deprival value as the methodology that must be used, it does require the Commission to have regard to COAG's preference for deprival value. As discussed above, the code defines deprival value as the lesser of ODRC and economic value. Like ODRC, the regulatory test is concerned with identifying and evaluating the optimal configuration and sizing of transmission assets in order to achieve a particular level of service. The regulatory test may take into account a wider range of alternatives than ODRC, but the basic objective of the two methodologies is the same.

[23] The code now requires the Commission to promulgate the regulatory test under clause 5.6.5. However, the need to ensure consistency with clause 6.2.3 remains part of this provision.

The Commission believes the use of the regulatory test gives due weight to this requirement of the code.

Under its extended ODRC methodology, MTC equates the economic value of Murraylink as being equal to its gross market benefits less the net present value of its opex costs. The Commission did not accept this proposition in the Preliminary View, noting that the regulatory setting determines the value of an asset to its owner, not the benefits that such an asset provides to the market.[24] Given that the economic value of a regulated asset to its owner often depends on the regulated revenue allowed under the code, the Commission has, in the past, relied on a valuation based on an ODRC approach rather than economic value.

Even where economic value could be defined by reference to the value of an asset to the market, rather than to MTC, it does not follow that the economic value of Murraylink can be determined by reference to its gross market benefits. For example, in its March 1999 report for the Commission on the regulatory test,[25] Ernst & Young described an asset's economic value as follows:

> "An asset's EV is the greater of the cost of the best substitute (at least cost) and its net realisable value. Net realisable value applies where the cost of substitutes is less than the asset's value if scrapped or otherwise disposed of.
>
> The economic value assessment is similar in some respects to the optimisation process, in the sense that both processes involve identification and evaluation of substitutes. However, whilst the optimisation process is confined to identifying network asset (or technology) substitutes, the EV is concerned with identifying all other possible substitutes including demand options (including non-supply), non-electricity-related supply options and generation technology alternatives. In that sense, the process called "optimisation" is essentially a subset of the economic value assessment."

In relation to whether such a valuation is consistent with the regulatory test, Ernst & Young stated:

> "Calculation of the ODV should be the exact reverse of calculating the augmentation benefit: if the augmentation is notionally dismantled, the Economic Value will be the net cost increase as a result, ie the difference in costs between a least-cost plan without the augmentation and a least-cost plan with the augmentation. The augmentation Test is basically equivalent to saying that the Economic Value should exceed the augmentation cost.
>
> However, this assumes that the same modelling and assumptions are used and that costs and benefits are measured on the same basis: ie direct costs and benefits to generators and Customers. Any differences between the two approaches may lead to inconsistent outcomes. Therefore, we propose that any Economic Value calculations should use the same models and analysis as have been proposed for the augmentation Test.[46] *[ie. the regulatory test]*.
>
> > [46] This latter formulation appears to suggest we are moving from a "maximise net benefit" test to a "show positive net benefit" test. However, because the economic value is calculated by reference to the best option available if the augmentation did not go ahead, ODV exceeding cost implies that the best option without augmentation delivers lower net benefit than the augmentation: ie the augmentation does indeed maximise net benefit"

[24] Preliminary View, p 39-40.

[25] *Review of the Assessment Criterion for New Interconnectors and Network Augmentation, Final Report to the ACCC*, Ernst & Young, March 1999, paras 5.3.1-5.3.2.

It is not appropriate to focus on the gross market benefits of the asset if there is an alternative that would produce a greater net market benefit. MTC's proposed constraint (ie. that Murraylink's asset value be capped at its gross market benefit less the net present value of its opex costs) ignores the fact that there may be an alternative which would produce greater *net* benefit to the market. Under Ernst & Young's approach to economic value, the economic value of Murraylink would be the value of such an alternative.

The Commission also believes it is consistent with the objectives in clause 6.2.2(j) and (k) (and the principles in clause 6.2.3(5)) to use the test that would be used to determine the value of a proposed new asset that is constructed to provide a prescribed service when determining the value of an asset that is classified as a prescribed service under clause 2.5.2(c). By contrast, introducing a third test (along the lines of the "extended ODRC" valuation methodology proposed by Murraylink) is likely to undermine these objectives by increasing uncertainty and creating the possibility of by-passing the requirements of Chapter 5 of the code.

In its submissions of 18 July 2003 and 12 August 2003, MTC set out the reasons why it considered the use of the regulatory test to be inappropriate.[26] The key arguments raised by MTC were as follows:

- The use of the regulatory test will result in a different asset value than that which would be derived from an ODRC valuation method, as applied in the past by the Commission, and from the "extended ODRC" methodology proposed by MTC. Further, the regulatory test is a significant departure from the ODRC or deprival value approach described in the Commission's Draft Regulatory Principles. The use of a regulatory test methodology that is not a deprival value approach may not comply with Chapter 6 of the code;

  With respect to (a) and (b), the Commissions believes, for the reasons discussed above, that the regulatory test will result in an asset valuation that is determined in a manner that is consistent with ODRC, even if it is not identical. The Commission believes that this approach gives sufficient weight to the requirements of clause 6.2.3(d)(4)(iv) of the code;

- the use of the regulatory test is inconsistent with statements made by the Commission in its authorisation of the Network Pricing code changes (which included clause 2.5.2(c)) and the Preliminary View that it will apply and ODRC methodology in accordance with the *Draft Regulatory Principles*;

  The statements relating to the authorisation of the Network Pricing Code changes are reproduced at page 37 above. While the Commission proposes to use the regulatory test to determine the asset base for Murraylink rather than a ODRC valuation (as suggested in those comments), its objective is the same, namely, to determine the optimal configuration and sizing of the asset.

[26] *Submission in response to Preliminary View*, MTC, 18 July 2003, p 6; *Submission on Stakeholder comments on the Preliminary View*, MTC, 12 August 2003, p 16-19.

MTC has referred to page 93 of the Commission's Preliminary View where it stated:

> "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.
> ...
>
> 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."

While the Commission believes that it has applied an asset valuation methodology that is consistent with an ODRC valuation, it is clear from the Preliminary View that this involved the use of the regulatory test rather than ODRC. To the extent that the above passage suggests that the Commission used an ODRC methodology instead of the regulatory test, it is erroneous.

- the regulatory test is more onerous and uncertain than any other methodology previously used and fails to place a value on the existing asset despite the fact that it is providing valuable service to the market;

  The use of the regulatory test ensures that Murraylink is valued in a manner that is consistent with the manner in which it would be valued were it a proposed new interconnector. While the regulatory test may differ from the asset valuation methodology that has been used to value existing transmission networks under clause 6.2.3(d)(4)(iii) of the code, it is the basis for the valuation of new large and new small network assets proposed under Chapter 5 of the code.[27] It should also be noted that the Commission does not propose to deny Murraylink any value, rather, it seeks to determine for Murraylink an asset base that reflects the alternative that maximises the net market benefit. This reflects the value that would have been ascribed to Murraylink had it been proposed as a new large network asset under Chapter 5 of the code.

- the regulatory test is unproven and may contain significant shortcomings. The regulatory test should not be accepted as the basis for a new asset value methodology for an existing major network investment made in good faith;

  The regulatory test has been in place and has been applicable to new interconnectors (or new small and new large network assets) since December 1999. It has been applied on multiple occasions by network service providers under Chapter 5 of the code and its application has also been the subject of consideration by NEMMCO, the National Electricity Tribunal and the Supreme Court of Victoria.

- the alternative projects considered for any valuation methodology should be strong substitutes, in that one reduces the gross market benefits expected from the other. Where partial substitutes that deliver a lower level of transfer capacity are

[27] The Commission also notes the limitations on its discretion to value existing transmission networks under clause 6.2.3(d)(4)(iii) (see page [ ] above).

considered, accurate assumptions need to be made about timing, benefits and costs of future augmentations that would be required if the partial alternative was built and that would be expected in the presence of the existing asset;

> The Commission is of the view that the use of the regulatory test will ensure that consideration is given to alternatives that have an acceptable degree of substitutability. The Commission is of the view that there is nothing in Chapters 5 or 6 of the code that requires the use of an asset valuation methodology that limits itself to the consideration of alternatives that provide the exact same level of service.

3.5.5 Cost of alternatives greater than the gross market benefits

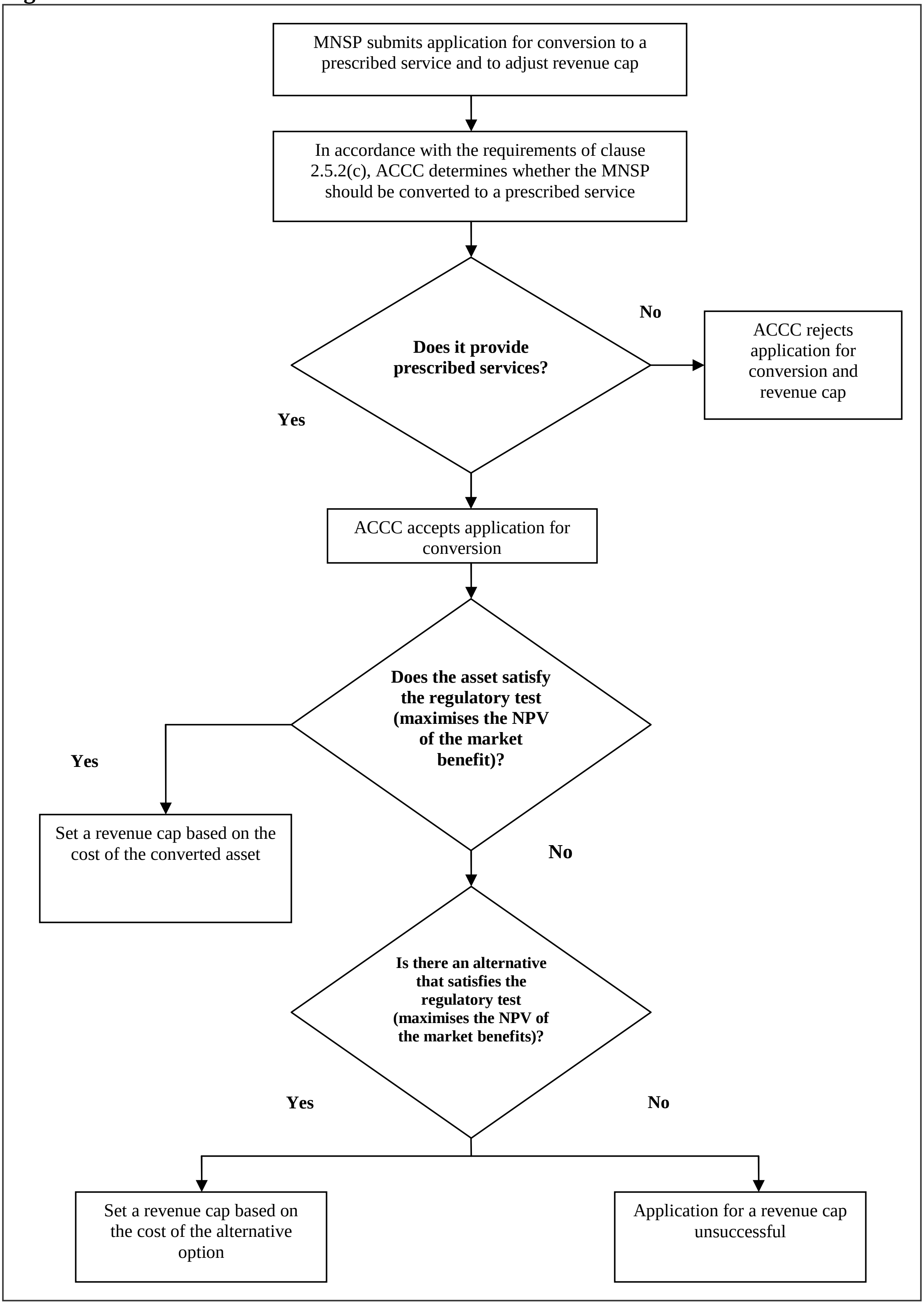
NERA notes that the Commission's approach to setting the regulatory asset value is unclear when the cost of alternative projects is above the gross market benefits under a conversion application.

The Commission notes that under the regulatory test, a proposed augmentation and its alternatives are assessed to determine which project maximises the net present value of the market benefits in most (although not all) credible scenarios. In instances where the proposed augmentation or the alternative projects do not maximise the net present value of the market benefits under most credible scenarios, the Commission considers that the likely outcome of such an assessment would be for the proponent not to proceed the proposal. That is, the 'do nothing' option would maximise the net present value of the market benefits.

Therefore, in the context of a conversion application, where the cost of the proposed project and its alternatives exceeds their respective gross market benefits under most (although not all) credible scenarios, the application for a revenue cap would be unsuccessful. The Commission considers that such an approach is consistent with the intent of the regulatory test.

The Commission's process in assessing a conversion application is outlined in figure 3.1, which is intended to aid the reader's understanding.

Figure 3.1 Conversion Process



3.6 Conclusion

Commission's Decision

The Commission believes that the use of the regulatory test to determine the opening asset base for Murraylink is justified by the need to ensure that a person seeking to convert a market network service to a prescribed service under clause 2.5.2(c) is treated in the same manner as a person seeking approval under Chapter 5 to construct a new network asset in order to supply a prescribed service.

The Commission is of the view that the regulatory test will produce an outcome that is consistent (even if not identical) with the outcome that would be achieved using an ODRC valuation methodology and is consistent with the requirements of Chapter 6 of the code.

The Commission is not convinced that the use of a methodology such as the "extended ODRC" methodology proposed by MTC would produce an outcome that is consistent with the regulatory test. Nor does the Commission believe that Chapter 6 of the code requires the Commission to use such a methodology in preference to the regulatory test or an ODRC valuation.

4 Regulatory Test Assessment

4.1 Introduction

As noted in chapter 3, the Commission considers that the use of the regulatory test to determine the opening asset value for Murraylink is justified by the need to ensure that a person seeking to convert a market network service to a prescribed service under clause 2.5.2(c) of the code is treated in the same manner as a person seeking approval under Chapter 5 to construct a new network asset in order to supply a prescribed service.

The regulatory test states:

> "A *new interconnector or an augmentation option* satisfies this 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; and
>
> An *augmentation* satisfies this test if -
>
> (a in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or
>
> (b in all other cases – the augmentation maximises the net present value of the *market benefit*
>
> having regard to a number of alternative projects, timings and market development scenarios."

The Murraylink interconnector has not been designed to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the code. Therefore, the Commission will undertake this assessment by determining which augmentation maximises the net present value of the market benefit. As is the case for new investments made by other TNSPs, the capital cost of the option that maximises the benefit to the market when applying the regulatory test will be used to determine the opening asset value when setting MTC's MAR. The Commission considers that its approach will produce an outcome that is consistent with the requirements of Chapter 6 of the code.

The remainder of this chapter:

- sets out the process for the selection of alternative projects (section 4.2);
- discusses the power transfer capabilities of Murraylink and the various alternatives (section 4.3);
- assesses the methodology for the calculation of the net market benefits for each of the alternative projects selected and outlines the various market development scenarios and sensitivity testing undertaken as part of the analysis (section 4.4 and 4.5);
- considers the cost of each of Murraylink and the alternative projects (section 4.6); and

- ranks the various alternatives to determine which project maximises the net present value of the market benefit, and therefore the opening asset value to be set for Murraylink (section 4.7).

4.2 Selection of alternative projects

4.2.1 MTC's application

MTC engaged engineering firm, Burns and Roe Worley (BRW), to select and cost alternative projects that could have provided the same technical service and gross market benefits as Murraylink. BRW identified and assessed six possible alternatives to Murraylink, the first four of which provided the same or similar level of technical service as Murraylink:[28]

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.

4.2.2 Commission's Preliminary View

Generally, the Commission believed that the range of projects specified by BRW was appropriate. These views were consistent with those of its consultant Saha. However, the Commission concurred with interested parties that an assessment under the regulatory test did not require an assessment of alternative projects that provide the "exact same level of technical service". While other alternatives were proposed in a number of submissions, the Commission's analysis of these alternatives indicated that their costs were typically higher than those of MTC's proposed alternatives after the Commission's adjustments. In regard to SNI, the Commissioned argued that the essential elements of SNI are captured in Alternative 1.

[28] 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.

4.2.3 Submissions on the Commission's Preliminary View

4.2.3.1 MTC's response to the Preliminary View

MTC argues that the Commission's approach is inconsistent with its previous ODRC valuation approaches and argues that the Commission has taken into account alternative projects that provide a different level of service to Murraylink. It argues that as a result, the Commission's approach is more onerous than the manner in which it has selected alternatives for other transmission networks in the NEM.

4.2.3.2 Submissions from other interested parties

Alternative projects

VENCorp, ESIPC, ElectraNet and the SA Minister for Energy concur with the Commission's Preliminary View that that the alternatives considered as part of the regulatory test do not need to provide an identical level of service as Murraylink.

ESIPC argues that the Commission should consider a range of reasonable alternatives that can provide equivalent or greater benefits to Murraylink, but should not be constrained to the exact location or sizing of Murraylink.

VENCorp argues that the alternatives that should also be considered by the Commission in its assessment are

- Horsham A[29] - which is an interconnection between Horsham and Tailem Bend, which was assessed by the Interconnector Option Working Group (IOWG) as having a transfer level of 220 MW at an estimated capital cost of $120 million; and

- Heywood A - which involves the provision of a third 500/275 kV transformer at Heywood and series compensation of the South East to Tailem Bend 275 kV lines in South Australia which was assessed in 1999 as having a adding an additional 130MW at an estimated cost of $60 million.

The Heywood A option is also supported by the Electricity Consumer Coalition of South Australia (ECCSA) and Energy Users Coalition of Victoria (EUCV). They also consider that the Heywood B augmentation, which is a third line between Heywood and Tailem Bend, should be considered as part of the Commission's assessment. Further, ECCSA and EUCV question the need for an interconnector with a transfer capacity of 220MW.

The ESIPC and ElectraNet note that if Murraylink is only capable of increasing the transfer capacity across the South Australian – Victorian border then a logical alternative to consider, and one that faces fewer environmental and planning hurdles, is an augmentation of the existing Heywood interconnector. However, ESIPC also states that if through some full or partial implementation of the so-called unbundled SNI Murraylink is able to contribute to power transfers from NSW then the existing alternatives would be reasonable.

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29 The Horsham A option consists of a 275kV line between Horsham and Tailem Bend; 220kV lines between Moorabool and Ballarat, and Ballarat and Horsham; and station works at Moorabool, Ballarat, Horsham and Tailem Bend.

4.2.3.3 MTC's response to submissions by interested parties

BRW re-emphasised that it only considered alternative projects which provide similar level of technical service as Murraylink. It also states that while it had initially considered the Horsham A project as an alternative project, its preliminary analysis indicated that the cost of the project was significantly higher than the other alternatives, without having regard to the need for undergrounding, and the level of service would have been lower than Murraylink. It also notes that its preliminary assessment did not take into account that the Horsham A option may need to incorporate environmental mitigation measures.

Regarding the Heywood A option BRW considers that this would only be a partial option, while the Heywood B option has been considered, in part, in Alternative 4.

4.2.4 Commission's considerations

Alternative projects

As noted in chapter 3, the Commission is applying the regulatory test to determine the appropriate revenue to apply to Murraylink and in applying the regulatory test, the Commission does not believe that alternative projects are required to deliver the exact same level of service as the proposed project. this will determine the manner in which the Commission will consider the alternative projects.

Regarding the selection of alternative projects, the Commission does not believe it appropriate that it should consider the Heywood A, Heywood B and Horsham A augmentations as "reasonable alternatives" projects to address a market need in its regulatory test assessment. Consistent with the findings of the National Electricity Tribunal and the Supreme Court of Victoria regarding SNI, the Commission considers that alternative projects should contain a level of similarity to the proposed augmentation. The Commission considers that an alternative project could be considered a reasonable alternative if it delivers substantial gross market benefits to all regions and or nodes.

The benefits of Murraylink largely arise from its ability to transfer power to South Australia and, in particular, the Riverland region of South Australia. The Commission's findings outlined in section 4.4 below are that while most of the benefits of Murraylink are from its power transfer capability into South Australia, a substantial portion of its gross market benefits arise from its delivery of power to the Riverland region. Therefore, the Commission believes that it is appropriate for it to limits its consideration of alternatives to those that provide power transfer capability to South Australia as well as to the Riverland region.

The Commission believes that if Murraylink was found not to deliver substantial gross market benefits to the Riverland region, and only provided benefits via its ability to delivers power from Victoria to South Australia, then it would have been appropriate to consider alternatives such as the Heywood A and B, and Horsham A augmentations which deliver power transfer capabilities into South Australia.

Therefore, in this assessment, the Commission does not believe that the Heywood A, Heywood B and Horsham A are sufficiently similar, in servicing the Riverland region, to the Murraylink project to be considered alternatives in its regulatory test assessment.

Optimal size of alternatives

The Commission notes that the need for an augmentation is driven by either code or jurisdictional obligations or, in the case of a market driven augmentation, come from the size of the market benefits available. As discussed below, there are significant market benefits from the development of an interconnector of the size and capacity of Murraylink and the alternative projects. The Commission notes that the transfer capabilities are similar to the power transfer capabilities of SNI. In the case of the AC alternatives considered, there are substantial benefits from including components such as Phase Shifting Transformers (PST). Therefore, the Commission believes that augmentation options that deliver similar power transfer capabilities as Murraylink are appropriate to consider in the context of this regulatory test assessment.

Augmentations to support an interconnector

In the appeal to the Supreme Court of Victoria it was argued, among other things, that the Tribunal erred by treating the SNI project as an interconnector within the meaning of clause 5.6.6(c) of the code (as it was prior to March 2002). MTC argued that SNI consisted of an interconnector plus related augmentations, and that the augmentations should have been separately assessed under the regulatory test. The Supreme Court rejected this argument, and instead agreed with the decision of the majority in the National Electricity Tribunal, who stated:

> "the establishment of a new interconnector may involve augmentations and if that happens those augmentations are to be treated within the regulatory asset base of the regulated interconnector. TransGrid's network is proposed to be 'augmented' to enlarge or increase the capability of what is proposed. A proper understanding of clause 5.6 and 5.5 makes it clear, in our opinion, that a proposal to establish an interconnector may (and in this case does) involve a 'transmission system augmentation proposal' ". [30]

[30] Murraylink Transmission Company Ltd v NEMMCO &Ors [2003] VSC 265, paragraph 66. More generally see discussion in paragraph 65-75.

The Commission considers that while the code no longer makes separate provisions for the assessment of interconnectors, the principles of the Court's decision remains intact. A new large network asset that is an interconnector can consist of both the actual interconnector plus other augmentations to the networks that are being connected. Therefore, the regulatory test is applied to the entire project, not the interconnector in isolation. Therefore, the Commission is of the view that if an interconnector is subjected to the regulatory test, and is found to satisfy the regulatory test, the works that are necessary to implement that interconnector, including the augmentations to an existing network that may be required are to be treated as if they have also satisfied the test.

Therefore, the Commission considers that Murraylink, Alternative 1, Alternative 2 and Alternative 3 include the interconnector as well as the augmentations to the existing transmission network to enable the transfer of 220MW[31].

Furthermore, the Commission is of the view that as the augmentations to the existing transmission network are required and included in either Murraylink or its alternative projects, and considered as part of the regulatory test assessment, then the augmentations for the option which maximises the net benefits to the market should be treated as having satisfied the regulatory test. For this reason, the Commission is satisfied that the transfer capacity of Murraylink and Alternatives 1, 2 and 3 with the augmentation to the Victorian network is 220 MW, and is appropriate for its regulatory test assessment.

The Commission notes that while the various transmission planners in the NEM may need to undertake a clause 5.6.6 process for such augmentations to ensure compliance with the code, it does not believe that a delay associated with any transmission planner following such a process will materially alter the results of its analysis.

4.2.5 Conclusion

The Commission will consider the following projects in its regulatory test assessment.

[31] The scope of the augmentations proposed by MTC have been assessed and approximately costed by VENCorp. The Commission has included the approximate cost of these augmentations under its regulatory test assessment to Murraylink and its alternatives.

Table 4.1: Options to be considered under the regulatory test

Project Name	Location and specifications
Murraylink	Red Cliffs to Monash 140 kV DC underground transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 1	Buronga to Monash 275 kV AC mostly overhead transmission line, initially operating at 220 kV, with substation augmentations at Buronga and Monash, including the augmentations to the Victorian network.
Alternative 2	Red Cliffs to Monash 140 kV DC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 3	Red Cliffs to Monash 220 kV AC mostly overhead transmission line, with substation augmentations at Red Cliffs and Monash, including augmentations to the Victorian transmission network.
Alternative 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.

A system diagram for each of the alternative projects is outlined in Appendix D.

Commission's Decision

In its regulatory test assessment, the Commission will consider the following projects:

- **Murraylink;**
- **Alternative 1;**
- **Alternative 2;**
- **Alternative 3; and**
- **Alternative 4.**

The location and specification of the options listed above is outlined in table 4.1.

4.3 Power transfers

4.3.1 Introduction

The power transfer capability of an augmentation is a critical input into the calculation of its market benefits. The greater the transfer capability of an augmentation then the greater its potential market benefits as assessed under the regulatory test.

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.

4.3.2 MTC's application

MTC states that at the time Murraylink was developed, the 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 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.

4.3.3 Commission's Preliminary View

The Commission's consultant PB Associates raised concerns that Murraylink would be unable to transfer power up to its stated capability. In response to the concerns raised by PB Associates, MTC submitted additional information in association with VENCorp which supported the 220 MW transfer capability rating. The Commission engaged PB Associates to undertake a further review of MTC and VENCorp's work, following which it was satisfied that if the additional augmentations are in place, Murraylink's rated capacity will be 220 MW. While further works may be required upstream in the NSW and Victorian networks to ensure greater reliability, at peak times, the Commission believed that this will only further enhance Murraylink's transfer capacity.

The Commission was therefore satisfied that with the additional augmentations in place Murraylink would be capable of delivering 220MW of power transfers.

4.3.4 Submissions on the Commission's Preliminary View

4.3.4.1 MTC's response to the Preliminary View

MTC notes that a power transfer capability is possible for Murraylink and the alternative projects selected provided that in the case of Alternatives 2 and 3 and Murraylink that there are additional augmentations to support the interconnector, and in the case of Alternatives 1 to 4 that there is a PST.

MTC argues that without the controllability provided by PSTs, Alternative 3 would be unable to provide more than approximately 60 per cent of Murraylink's power transfer capabilities into South Australia and would be limited to flows of around 140 MW.

4.3.4.2 Submissions from other interested parties

The ESIPC, ElectraNet SA, the Hon Patrick Conlon, and the ECCSA and EUCV note that there have been significant differences between the technical feasibility and structure of the proposed alternatives and suggests that either the Inter-Regional Planning Committee (IRPC) or the IOWG be asked to assess the power transfer capabilities of Murraylink and its alternatives.

VENCorp conducted an analysis of the transfer levels of both the existing Murraylink interconnector and Alternative 3 project upon which the Commission based its revenue cap in the Preliminary View (see Appendix E). VENCorp's analysis found that the power transfer capability of the Murraylink Alternative 3 without a PST would only be around 130MW. It states that in order to achieve a 220MW capability, Alternative 3 would require:

- a PST (with a 35 degree phase shift); and
- an Static Var Compensator (SVC) at Monash.

In addition to the following augmentations in the Victorian network:

- an additional 180MVAr of reactive plant to be located in Victoria;
- tripping schemes; and
- location equipment.

ElectraNet agrees that voltage control equipment would be required at Monash substation to support an AC alternative to Murraylink. However, it argues that installing a +120/-110 Mvar SVC at Monash Substation at a cost of approximately

$19 million (including spares) is inappropriate and suggests the following alternatives:

- Installation of a smaller 35 Mvar SVC facility at Monash substation at an estimated cost of $5 million (excluding spares).
- Installation of 40 Mvar Thyristor Switched Capacitors (TSC) at Monash at an estimated cost of $5 million (excluding spares).
- The establishment of a bypass circuit breaker across the PST to limit voltage variations at an estimated cost of approximately $2 million (excluding spares).

4.3.4.3 MTC's response to submissions by interested parties

MTC concurs with VENCorp and ElectraNet that an SVC is required in the Riverland region to cope with changes in power flows that may result from a large generating unit tripping, as well as deferring the requirement for the Robertstown to Monash 275kV line by providing voltage support to the 132kV system. However, MTC argues that only ElectraNet's first solution, with additional switched capacitors, is a suitable alternative to address the Riverland voltage profile but would not provide an equivalent service to Murraylink.

Further, MTC agrees with VENCorp's findings in relation to the need for a PST to facilitate the transfer of power between Victoria and South Australia.

4.3.5 Commission's considerations

While a number of parties argue that either the IRPC or IOWG should have been asked by the Commission to conduct an assessment of the power transfer capabilities of the alternative projects, the Commission notes that neither the IRPC nor the IOWG are required under the code to conduct an analysis of a conversion application.

In any event, the Commission notes that VENCorp and ElectraNet have provided significant independent information on the power transfer capabilities of Murraylink and its alternative projects as well as on the technical configuration of the alternative projects. VENCorp's analysis highlights that in a network where interconnectors are operating in parallel to one another, a PST is required to facilitate the transfer of power. The Commission notes that this was also recognised in the SNI assessment process where a PST was located in the Victorian network at Jinderra in Victoria. This is also supported by MTC's analysis which highlights the effect on the gross market benefits of Alternative 3 without a PST. However, in the case of the Alternative 4, the Commission is of the view that a PST would not be required given that this option is an upgrades to the existing network.

Regarding the need for voltage support, while not affecting the power transfer capability of Murraylink and its alternatives, the Commission must come to a landing on the appropriate configuration of the alternative projects. While the Commission does not disagree with the information submitted by MTC, it must base its analysis on the needs of the market. MTC believes that ElectraNet's solution for the installation of a 35 MVA SVC facility at Monash is appropriate, therefore the Commission will make its decision based on a 35 MVA SVC at Monash.

4.3.6 Conclusion

Following the analysis of power system transfers by Murraylink, VENCorp and ElectraNet the Commission is satisfied that the capacity of Murraylink, Alternatives 1, 2 and Alternative 3, including a PST and an SVC, and Alternative 4 will be 220 MW provided the additional augmentations are in place. A SVC has also been included in Alternative 4.

Table 4.2 Power transfer capability (MW)

Project name	Power Transfers
Murraylink	220
Alternative 1	220
Alternative 2	220
Alternative 3	220
Alternative 4	220

Commission's Decision

The Commission is satisfied that the capacity of Murraylink, Alternative 1 and 3, including a PST and an SVC, , and Alternative 4 including a SVC will be 220MW provided that the additional augmentations are in place for Murraylink, Alternative 1, 2, and 3.

4.4 Gross Market Benefits

4.4.1 Introduction

In undertaking an assessment under the market benefits limb of the regulatory test, the Commission must calculate the market benefits of the Murraylink project and its alternatives. The greater the need for the interconnector and the augmentation 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 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 benefits that apply to a specific project are considered. The relevant set of benefits may vary across different projects and this is entirely appropriate. Furthermore, if there are benefits which cannot be measured in financial terms, or do not relate to producer or consumer surplus, such benefits do not qualify to be included in the test.

In particular, section (1)(b) of the notes accompanying the regulatory test provides guidance on what should be included in a market benefit assessment. 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 and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

4.4.2 MTC's application

As part of MTC's methodology for the calculation of the regulatory cost of Murraylink, TEUS conducted a study to determine the scope and magnitude of Murraylink's market benefits. MTC also engaged Charles River Associates Ltd (CRA) to comment on and assess TEUS's market benefits study.

As highlighted in the table below, TEUS identifies four market benefits that Murraylink and its alternative can bring to the NEM.

Table 4.3: TEUS: Summary of the gross market benefits for the base case

Type of benefit	NPV of gross market benefits ($m)	description
Energy savings	79.2	MTC notes that Murraylink provide 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. Furthermore, MTC submits that Murraylink also reduce the economic costs associated with voluntary load reductions and/or curtailments by reducing the expected frequency and magnitude of such events.
Capacity deferral / deferred market entry	51.9	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	58.0	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/MWh, which is the value of lost load set down by the code.
Riverland deferral	25	MTC notes that Murraylink provide additional supply capacity to the Riverland area from the summer of 2002-03, deferring the need for major transmission augmentation up to 2012-13
Total gross market benefits	**214.2**	

TEUS's calculations provide that the gross market benefits provided by Murraylink and its alternatives 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 the alternative section of this chapter.

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 per cent (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.

As the Murraylink's design life is 40 years, the analysis undertaken by TEUS is for a 39.5 year period. TEUS highlights that 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 the 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 to be 220 MW. 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.

4.4.3 Commission's Preliminary View

In its Preliminary View, the Commission generally, subject to specific aspects it addressed (outlined below), did not find the methodology adopted by TEUS for the determination of the gross market benefits to be inconsistent with the current wording of the regulatory test. However, the Commission considered that some adjustments were required in light of comments by interested parties. These include:

- a reduction in the gross market benefits of approximately $3.08 million given that the Commission was advised that the augmentations, which were to allow Murraylink to deliver 220MW, could be in place by July 2005;

- a reduction in the gross market benefits by approximately $10 to $15 million as it appeared, given the information provided to the Commission at that time, that Murraylink would be unable to provide support to the Riverland region beyond 2008; and

- a reduction in the gross market benefits by approximately $20 to $25 million due to the removal of a PST from Alternatives 1, 3 and 4.

In regard to the reliability benefits, the Commission was of the view that it did not find the TEUS assumptions adopted to be inappropriate and inconsistent with the code and the regulatory test if TEUS applied its methodology beyond 2005. However, the difference between the approach adopted by TEUS in its application and using the reliability entry plant through to July 2005, and the TEUS unserved energy methodology from July 2005, did not appear to have a material impact on the estimated gross market benefits.

The Commission concurred with interested parties that each alternative proposed by MTC has different technical characteristics and need not come from the same source, and thus is likely to provide different levels of benefits. However, the Commission noted that due to the way that the alternatives were configured it was unlikely that the gross market benefits of the alternatives would be significantly different to Murraylink.

4.4.4 Submissions on the Commission's Preliminary View

4.4.4.1 MTC's submission to the Preliminary View

Impact of augmentation timing

TEUS submits that the gross market benefits of Murraylink decrease by approximately $3.1 million when implementation of the augmentations is delayed until January 2005. TEUS has calculated Murraylink's gross market benefits on a monthly basis using a load transfer limit of 110MW during peak load conditions though to December 2004, with the limit increasing to 220MW in January 2005.

Riverland deferral benefits

TEUS notes that TEA has completed new and detailed analysis of the Riverland electricity network and its augmentation needs using the most recent ElectraNet/ESIPC load forecasts and considering the South Australian Electricity Code requirements. TEA's analysis, using the ElectraNet/ESIPC load forecast, notes that without Murraylink, the existing Robertstown to North Bend lines are unable to meet forecast load for the coming summer. TEA's load flow analysis demonstrates that Murraylink would be able to support the Riverland, delaying major network augmentations (currently costed by ElectraNet at $44.7 million) until after the summer of 2013/14, which is beyond the 2011/12 summer previously submitted.

TEA submits that until the summer of 2013/14, only moderate and progressive additions of capacitor banks (costed by TEA at $1.6 million) would be required to provide voltage support in the region. It notes that the capacitor banks solve a temporary voltage support problem, and would be available for salvage or redeployment to new locations elsewhere on the grid, once the major Riverland augmentations are in place.

TEUS notes that the longer deferral period for major Riverland augmentations would increase the high growth case gross market benefits by $8.3m. Similar adjustments for the low growth case and base produce increased benefits of $6.8 million and $7.9 million, respectively. TUES concludes that the original Riverland deferral timing and cost assumptions understate the value of Riverland deferral benefits.

4.4.4.2 Submissions by other interested parties

Riverland Deferral Benefits

ElectraNet notes that in response to its regulatory test process for the Riverland region, it has identified a least cost feasible option that is estimated to cost approximately $1 million per annum (based on a 5 year term). ESIPC submits that as a result the Murraylink Riverland deferral benefit can be no more than around $3.2 million, based on a discount rate of 9 per cent and $4 million spread from 2004-2007.

Deferred capacity and reliability benefits

ESIPC does not agree that the regulatory test allows for the calculation of both reliability and deferred capacity, and submits that according to its calculations, the benefits attributed to Murraylink for deferred capacity and reliability benefits are close to $5 million. ESIPC submits that such benefits are close to zero because South Australia and Victoria have historically very similar weather patterns and a high degree of coincidence with respect to peaks. It notes that in such a circumstance, one or both of the states would need to have reserves over and above their individual reserve requirements to be able to share reserves, and without the ability to share reserves, there can be no deferred capital benefits attributable to Murraylink.

ESIPC notes in regard to the modelling of the deferral capacity and reliability benefits that MTC has added market entry generators according to whether the spot price supports their viability. ESIPC submits that this ignores the prescribed reliability standards and produces results that are inconsistent with NEM requirements. ESIPC highlights that, no new entry occurred in the low growth cases until after 2012 in clear breach of NEMMCO’s capacity requirements. ESIPC has investigated the levels of new capacity required in each region both with and without Murraylink and any additional deferral that could be achieved based on the relaxation of the constraints that Murraylink is proposing to achieve through its additional investment. It argues that the construction of Murraylink on its own and the subsequent relaxation of the network constraints do not alter the requirements for new capacity. Therefore ESIPC is of the view that there is no justification for the inclusion of capital deferral benefits in the benefits calculation.

NERA notes that it would be desirable for the Commission to confirm that the methodology adopted by MTC for the calculation of reliability benefits is acceptable, since it is relevant more generally in applications of the regulatory test by transmission network service providers. NERA also notes that the TEUS analysis projects an increase in the future amount of unserved energy, which would put it significantly above acceptable reliability levels. NERA comments that the approach does not therefore appear to reflect what would happen in practice under a mature market.

Fuel Benefits

ESIPC submits that based on its modelling, the fuel benefits attributable to Murraylink are in the order of $50 million, compared to $79 million calculated by TEUS. ESIPC notes that for Murraylink to create fuel benefits, it must be able to show that its presence results in a change in generation dispatch such that there is more generation from cheaper, often coal based, generators and less from more expensive ones. It notes that the historical pattern of binding constraints across the existing Heywood interconnector shows a clear trend towards reducing reliance on the interconnector. ESIPC submits that any fuel benefits provided by Murraylink over and above that of Heywood must, therefore occur either during the current 10 per cent constrained periods or by reducing the overall losses of transferring power between states.

Benefits of AC and DC interconnectors

ElectraNet notes that AC interconnectors have a number of advantages over DC interconnectors. For example, an AC interconnector will typically respond in a beneficial manner to power system disturbances. Murraylink's response is limited:

- Murraylink cannot supply an isolated, islanded portion of the power system (eg. the Riverland following loss of both 132kV transmission line circuits from Robertstown to North West Bend); and
- pre-dispatch of Murraylink will be required to provide network support under certain operating conditions because it does not respond automatically to changes in demand, which could lead to uneconomic dispatch of generation.

TransGrid notes that based on its modelling, Murraylink's actual losses are significantly higher than in its market benefits analysis. Therefore TransGrid argues that the market benefits for Murraylink will be too high. TransGrid notes that the Buranga-Monash portion of SNI has significantly lower losses than Murraylink across the whole range of power transfer capacity. TransGrid further notes that when Murraylink was operating as a MNSP, losses were part of Murraylink's operating costs. If Murraylink becomes a prescribed service, these losses will be paid for by consumers in the NEM.

Gross market benefits of alternative projects

TransGrid submits that the benefits of Murraylink and the alternative projects need to be considered. NERA reiterates previous comments that it is the net benefits of alternative projects which should be relevant comparator in deriving an MNSP's regulatory asset value for conversion purposes, rather then the cost of alternative projects, given that the gross market benefits may differ between projects.

NERA notes that failure to consider the net benefits of alternative projects in determining the regulatory asset value of Murraylink means that the outcomes of the conversion process may be materially different to outcomes of the regulatory process under Chapter 5 of the code. It notes that a material difference may arise because:

- ignoring differences in the market benefits may limit the alternative projects considered;
- ignoring the differences in market benefits may affect the selection of the project which has the greatest ‘net market benefit’; and
- where the gross market benefits of alternatives differ, focusing only on the costs of alternative projects means that the approach does not result in the same regulatory asset value that would have applied if the processes under chapter 5 of the code has been followed.

Augmentations and gross market benefits

NERA comments that there is no commitment by MTC or another party to undertake the proposed augmentations to the Victorian network, and therefore notes that to the extent that there is not current commitment to carry out the works necessary to augment Murraylink’s transfer capacity, the gross market benefit would be more appropriately calculated on the basis of 180MW capacity.

4.4.4.3 MTC’s response to submissions by interested parties

Historical patterns versus forecasts of Heywood constraints

TEUS contends that all other things being equal more constrained hours might indicate that higher incremental market benefits could be anticipated from additional interconnection capacity. However, it notes that this observation does not mean that the incremental benefits of additional interconnection capacity during the period of Heywood constraints are not consequential. TEUS highlights that the value of incremental market benefits is affected by more than the number of hours constraints, it is also affected by the value of energy flows during these periods of constraints, and during periods in which the marginal inter-regional losses have decreased as a result of additional interconnection capacity.

TEUS also notes that regional changes in load and the siting of new generation can be expected to create year-on-year fluctuations in the level of congestion on the Heywood interconnector. It states that there are no reasons to anticipate that the steep decline between 1999-2002 observed by ESIPC can or will continue indefinitely into the future. TEUS notes that its modelling indicates a stabilisation at or near current levels is reasonable and likely.

Riverland Deferral Benefits

TEUS highlights that its calculation of Murraylink’s Riverland deferral benefits remains unchanged for the following reasons:

- without Murraylink, the existing Robertstown to North West Bend lines are not adequate to carry the forecast load for the coming summer;
- ElectraNet would have constructed the Robertstown to Monash 275kV transmission line and the associated 275kV substation works to provide support to the Riverland region to meet this need had Murraylink not been built and converted to regulated status; and

- with Murraylink operating as a regulated interconnector, the Robertstown to Monash transmission line will not be required until after the summer of 2013/14.

Treatment of Losses

TEUS notes that it has reviewed the loss assumptions used in the PROSYM market simulations and confirms that the correct loss functions have been used. In the process, TEUS determined there was a typographical error in TEUS's memorandum of 19 March 2003 and has provided the correct loss equation, which is presented below:

$$Losses = 3.76 + 0.00008 \times Flow + 0.00017 \times Flow^2$$

4.4.5 Commission's considerations

Augmentations and gross market benefits

The Commission notes that as part of MTC's application for conversion and MAR, the gross market benefits calculated by TEUS were based on Murraylink, plus the augmentations proposed by MTC to the Victorian network delivering 220MW. The Commission however recognises comments made by NERA which highlights that the calculation of the gross market benefits includes investments not yet committed to but treated as committed in the gross market benefits calculation. NERA suggests that in the absence of a commitment to fund the additional augmentations, the gross market benefits should be assessed at a transfer capacity of 180 MW.

In reference to section 4.3 of this chapter, the Commission notes that based on information provided to it by MTC and interested parties, the Commission considers that the inclusion of the augmentations to the Victorian network are likely to enable Murraylink to deliver 220 MW. Furthermore, as noted previously, the Commission is of the view, consistent with the findings of the Supreme Court of Victoria on the SNI appeal, that if augmentations to the existing transmission network are required and included in either Murraylink or its alternative projects, and considered as part of the regulatory test assessment, then the augmentations for the option which maximises the net benefits to the market should be treated as having satisfied the regulatory test. For this reason, the Commission is satisfied that the transfer capacity of Murraylink and Alternatives 1, 2 and 3 with the augmentation to the Victorian network is 220 MW. Therefore the Commission is satisfied that the augmentations to the Victorian network satisfy the regulatory test.

The Commission notes that while the various transmission planners in the NEM may need to undertake a clause 5.6.6 process for such augmentations to ensure compliance with the code, it does not believe that a delay associated with any transmission planner following such a process will materially alter the results of its analysis.

The Commission notes that while the Murraylink project has been assessed under the regulatory test, the Commission notes that the operating dates of both portions of the Murraylink project are different. The Commission notes that the augmentations are unlikely to be in place before January 2005. The Commission believes that the gross market benefits need to be adjusted to take this into account.

TEUS has advised that gross market benefits of Murraylink decrease by approximately $3.1 million when implementation of the augmentations is delayed until January 2005. While the timing of the augmentations is uncertain given that such augmentations will be required to be coordinated by VENCorp under the Victorian arrangements[32], the gross market benefits of Murraylink and Alternatives 1, 2 and 3 will fall each year that the augmentations are delayed. Therefore, the gross market benefits of Murraylink and Alternatives 1, 2 and 3 should be reduced by $3.1 million to take into account the likely timing of the augmentations.

With respect to concerns raised by NERA regarding a commitment to undertake the augmentations to the Victorian network, the Commission notes that VENCorp states that it will be in a position to commence the procurement process for the augmentations when the Commission releases its final decision, and VENCorp board approval is received. Given this statement, and the fact that the augmentations are being assessment by the Commission under the regulatory test during this process, the Commission is satisfied that there is a commitment to proceed with the augmentations by VENCorp, given they have passed the regulatory test.

Riverland Deferral Benefits

In its Preliminary View, the Commission concluded, based on information provided to it by ESIPC and its consultant, that the Riverland deferral benefits estimated by TEUS appeared to be overstated given that Murraylink did not appear to provide adequate security to the Riverland beyond 2008. However since the Preliminary View, further information has been provided to the Commission on the extent and value of the Riverland deferral benefits attributable to Murraylink and its alternative projects.

At the public forum and in its submission, ElectraNet indicated that its tendering process in October 2002 seeking to identify potential solutions for the Riverland network support, revealed a network support option, other than Murraylink, that could defer the $40 million expenditure for the transmission line from Robertstown to Monash and associated works, until 2008 at a cost of $1 million per annum. In its submission, ESIPC confirmed knowledge of this option. ElectraNet has since advised the Commission that the estimate of $1 million per annum did not include one off costs for communications, monitoring, control and metering equipment. Incorporating these costs will result in an annual cost of $1.4 million per annum.

However, new studies undertaken by TEA show that with Murraylink, network augmentations in the Riverland can be deferred until 2013/14. The Commission notes that in order to achieve deferral until 2013/14, TEA indicates that additional reactive support costed at $1.6 million (2 x 18 MVAr blocks) will be required, one additional block prior to the summer of 2008/09 and the other before the summer of 2010/11.[33]

[32] Given that the augmentation constitute augmentations to the shared network in Victoria, the augmentations would need to go through a tendering process run by VENCorp, or if VENCorp believes that the works are not contestable then it will negotiate with SPI PowerNet, the incumbent transmission owner in Victoria.

[33] TransEnergie Australia, '*Murraylink Riverland Support – Technical Capabilities, 24 June 2003*, attached to submission by MTC of 30 June 2003.

The Commission considers that, based on advice provided by ElectraNet the Riverland deferral benefits until 2008/09 should be costed at $1.4 million per annum. After that time, until 2013/14, the Commission is of the view based on studies by TEA, that Murraylink will be able to defer the Riverland augmentation with the additional reactive support in place. This would result in a decrease to the benefits attributable to Riverland deferrals of approximately $6 to $8 million, which results in a Riverland deferral benefit of approximately $18 million for the base case.

Reliability Benefits

The Commission notes comments by ESIPC and NERA regarding the methodology of TEUS for the calculation of the reliability benefits. ESIPC notes that that TEUS's method for the calculation of reliability benefits for Murraylink and its alternatives differs from the approach adopted in the evaluation of SNI and SNOVIC 400.

NEMMCO's assessment compares the reserve levels established by the Reliability Panel for each region in the NEM with the expected market generation under these reserve levels. Where NEMMCO identifies shortfall, it adds sufficient reliability generation such that the reserve criterion was met. VENCorp in its Latrobe to Melbourne assessment[34]also adopted this approach. However, the Commission notes that VENCorp assumed that its reliability plant is offered into the market at short run marginal cost (SRMC) for all market development scenarios except for the long run marginal cost (LRMC) case. In contrast, NEMMCO in the SNI and SNOVIC reports assumes the reliability plant is offered into the market at VoLL for all market development scenarios except for the least cost-planning scenario.

TEUS's approach to determining reliability benefits is different to the approach adopted by NEMMCO and VENCorp. In TEUS's assessment, no reliability plant is commissioned, unlike the VENCorp and NEMMCO approach. TEUS estimates reliability benefits as the change in un-served energy (USE) between the case which includes Murraylink and that which does not. The annual reliability benefit is calculated as the change in estimated USE multiplied by VoLL. The Commission notes that there has not been a consistent approach to valuing reliability benefits and even when reliability entry plant has been assessed, different assumptions have been adopted.

The regulatory test does not provide a prescriptive means of calculating reliability benefits, although the issue of whether the regulatory test needs to be prescriptive is being considered by the Commission as part of the review of the regulatory test. The regulatory test currently states in regard to the calculation of market benefits for the purposes of reliability that:

> "(1) In determining the market benefits, the following information should be considered:
>
> (b) reasonable forecasts of:
>
> ii. the value of energy to electricity consumers as reflected in the level of VoLL;

[34] VENCorp, *Economic Evaluation: Optimising the Latrobe Valley to Melbourne electricity transmission capacity*, February 2002.

> (5) In determining the market benefits, the analysis should include modelling a range of reasonable alternative market development scenarios….These scenarios should include projects undertaken to ensure that relevant reliability standards are met."

While the Commission prefers the approach adopted by NEMMCO for the determination of reliability benefits, the Commission considers that the approach of NEMMCO, VENCorp and MTC are not inconsistent with the current wording of the regulatory test. The Commission notes that the Ernst & Young report[35]commented, in regard to the calculation of reliability/security benefits, that:

> "System reliability is a measure of how often load needs to be shed by NEMMCO to preserve system security. The Reliability Panel – which reports to NECA – is responsible for setting reliability standards. We understand that the current standard is that, on the regional average, no more than 0.002% of load is disconnected.
>
> …[in measuring the reliability benefits provided by an augmentation] is to measure the cost of USE with and without the interconnector, in which case the appropriate level of VoLL must be chosen. A figure of $5,000/MWh is used in the spot market to cap spot prices. This is the maximum benefit that a generator can obtain through spot market for enhancing supply reliability. However, we have been told by various stakeholders that a VoLL of around $5,000/MWh is inconsistent with the maintaining the reliability standards [of 0.002%] and that VoLL of around $25,000/MWh (or even higher) would be necessary to provide sufficient market signals at peak to achieve the reliability standards." (page 28)

The approach highlighted by Ernst & Young is consistent with the methodology adopted by MTC for the calculation of the reliability benefits for Murraylink and Alternatives 1 to 4.

Therefore the Commission does not find that the TEUS assumption and approach adopted for calculating reliability benefits to be inappropriate and inconsistent with the regulatory test. Furthermore, the gross market benefits of Murraylink and the alternative projects under the approach adopted by NEMMCO is considered in market development scenarios and sensitivity analysis. The Commission notes that the outcomes of the regulatory test do not change whether reliability benefits are determined under NEMMCO's approach or MTC's approach.

Capital deferral and reliability benefits

The Commission notes comments made by ESIPC that the regulatory test does not allow for the calculation of both reliability and deferred capacity benefits, and comments by interested parties that the TEUS methodology has the potential to double count deferred merchant entry benefits and reliability benefits.

The Commission notes that the deferral of capital spending and fixed operating and maintenance for new merchant entry plant was recognised in the IRPC's evaluation of SNI as representing a market benefit.[36]

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[35] Ernst & Young, Final report to the ACCC, *Review of the Assessment Criterion for New Interconnectors and Network Augmentation.*

[36] IRPC. *SNI Stage 2 Report*, 26 October 2002; IRPC, *SNI Stage 1 Report– Proposed SNI Interconnector*, 26 October 2001.

The Commission also notes that the Ernst & Young report[37] states that:

> "Impacts on generation costs is likely to be a benefit associated with augmentation. Costs should include both fixed costs (eg capital costs, fixed O&M etc) and variable costs (fuel costs, O&M etc).
>
> Given that generation cost reductions will be a major reason for augmentation, these costs need to be fully captured" (page 27).

The Commission understands that in the SNI regulatory test evaluation, no market benefits were attributed to market entry capacity deferrals, however a significant amount of benefits was attributable to reliability capacity deferral (SRMC, medium growth, 9 per cent discount rate produced benefits of approximately $166 million). On the other hand, in the Murraylink assessment MTC has recognised market entry capacity deferral (approximately $55 million for the base case) and reliability benefits (not reliability capacity deferral. TEUS values Murraylink's reliability benefits at approximately $60 million when VoLL is set at $10,000/MWh).

The Commission agrees with ESIPC that if TEUS calculated reliability benefits adopting NEMMCO's or VENCorp's approach (reliability entry plant methodology), and also accounted for benefits relating to deferred merchant entry, then there would be a double counting of these benefits. However, the Commission believes that MTC's assumptions and methodology adopted for calculating reliability benefits are not inappropriate or inconsistent with the regulatory test. As such, under the approach adopted by MTC for calculating reliability benefits, there would not be a double counting of capacity deferral. The Commission is satisfied that there has not been a double counting of deferred merchant entry benefits and reliability benefits in TEUS' market benefit assessment.

Energy benefits

The Commission notes comments by ESIPC regarding the historical patterns of constraints on the Heywood interconnector and its effect on the fuel benefits attributable to Murraylink. ESIPC observes that the historical patterns of binding constraints across the existing Heywood interconnector shows a trend towards reducing reliance on the interconnector.

The Commission firstly notes that the energy benefits calculated by TEUS are not just fuel benefits, but incorporates the benefits associated with the reduction in fuel costs through the NEM, and the reduction in the cost of activating interruptible load.

With respect to the Heywood interconnector constraint hours in the TEUS modelling, the Commission notes that TEUS has reviewed the projected flows on the Heywood in its modelling of the gross market benefits of Murraylink. TEUS submits that its PROSYM simulations project the percentage of hours Heywood constraint to range from 5-15 per cent over the 2003-2012 horizon, with an average 10.2% for the base case (without Murraylink) simulation, and 9.65 per cent for the LRMC bidding case (without Murraylink). The Commission agrees with TEUS that these figures generally are in accordance with the historical data submitted by ESIPC.

[37] Ernst &Young, op cit

Furthermore, while more constrained hours might indicate that higher incremental market benefits could be anticipated from additional interconnection capacity, this observation does not mean that the incremental market benefits of additional interconnection capacity during the period of Heywood constraints are not consequential. As noted by TEUS, the value of the incremental benefits is affected by the value of energy flows during the periods of constraint, and during periods in which the marginal losses have decreased as a result of additional interconnection capacity.

The Commission agrees with ESIPC that the fuel benefits attributable to Murraylink will depend on the assumptions adopted and will vary with the market development scenarios assessed. The fuel benefits will also vary when SRMC and LRMC is assumed, and this has been demonstrated with the LRMC market development scenario presented by MTC. As noted in the market development scenarios and sensitivity section, the regulatory test is concerned with the ranking of alternative projects under credible market development scenario, rather than determining a 'most likely' or 'median' gross market benefit. The gross market benefits, and more importantly the net market benefits have been considered under SRMC, LRMC, and other assumptions, to test the variability of the fuel benefits (along with other benefits identified by TEUS) attributable to Murraylink and its alternatives to different assumptions.

Gross market benefits of alternatives

NERA and TransGrid reiterated concerns with respect to the assumption that the gross market benefits of the alternative project are equivalent to that of Murraylink. The Commission's consultant Saha made a similar observation in regard to Alternative 4, which is an upgrade of the Heywood interconnector and augmentations in the Riverland region. It stated the following:

> "…Alternative 1, 2, and 3 provided by BRW are broadly consistent with an appropriate choice of alternatives for determining the DORC of Murraylink in that they provide similar technical services, but do not provide higher level of service.
>
> On the other hand, the technical services provided by Alternative 4 appear to us as 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 interconnectors, and does not provide a direct linkage between the South Australian and NSW market region…" (page 6)

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.

The Commission notes that if it is to adopt the assumption that the gross market benefits of Murraylink's alternatives are equivalent to the market benefits of Murraylink in a market benefits assessment under the regulatory test, when the gross market benefits are materially different, the Commission would be conducting a least cost rather than a maximisation of net benefits assessment. The Commission is of the view that this is contrary to the intent of the regulatory test.

The Commission notes that while the alternatives provided are configured so as to provide the 'same technical service' as Murraylink based on the alternatives providing transfer capability into and out of the Riverland region, other aspects of the technical service (such as loss equations, impact on constraint equations of other interconnectors, and forced outage rates) might represent differences. Under MTC's approach, it has assumed that given the alternative projects provide the same technical service, the losses, constraint impact, and outage rates of the alternative projects were considered to be no different to Murraylink.

The Commission has since requested that MTC look into whether the gross market benefits of Murraylink's alternatives are materially different to the gross market benefits of Murraylink. The Commission was concerned that should the gross market benefits of the alternatives exhibit materially different benefits to Murraylink, then this could affect the outcome of the regulatory test and the ranking of Murraylink and its alternative projects under the market development scenarios and sensitivity analysis.

TEUS provided the gross market benefits of Murraylink, Alternative 3, and Alternative 4.[38] With respect to Alternative 3, TEUS calculated the gross market benefits of Alternative 3 to incorporate the appropriate loss equation. TEUS notes that the gross market benefits are approximately 2 per cent lower than Murraylink and that the difference is primarily due to lower energy benefits, caused by different loss functions. It also notes that energy flows were not sufficiently different to change the pattern of market energy, thus little change in market entry and reliability benefits. The gross market benefits are presented in the table below.

In regard to Alternative 4, TEUS was advised by BRW that the losses over the Vic-SA interface and the loss function is likely to reduce by a small amount to approximately 94 per cent of the original loss function.[39] It notes that although the revised Heywood loss curve is lower, total losses are higher than the Murraylink scenario because in hours with high flows (>500MW), the incremental losses on Heywood are higher than if the flows above 500MW have had been distributed onto Murraylink. Furthermore, TEUS highlights that the change in energy flows results in a change in the merchant entry schedule which in turn causes an increase in reliability benefits relative to Murraylink. The gross market benefits are presented in the tables below.

TEUS has advised that Alternative 2 has similar technology to Murraylink and therefore the representation of Murraylink and Alternative 2 within the PROSYM and MARS models would produce similar gross market estimates. The Commission notes

[38] For this assessment, TEUS assumed: base case load growth, SRMC bidding, 2012 simulation termination year, $29,600/MWh value of unserved energy, commencement date of 1 September, and a discount rate of 9 per cent.

[39] TEUS completed the its modelling for alternative 4 using the revised Vic-SA interface (Heywood interconnector) loss function, with the increase in the Heywood transfer limits to reflect the relaxation of constraints provided by Alternative 4. The limits have been revised to: Victoria to SA flow, from 500MW to 720MW, and SA to Victoria flow, from 250MW to 400 MW.

that the only difference is that Murraylink is an underground DC link and Alternative 2 is an overhead DC link. Furthermore, both options link at the Redcliffs substation (Victoria) and the Monash substation (South Australia).

The Commission notes that while Murraylink and its alternatives provide links between Victoria and South Australia, Alternative 1 links at Buronga substation in New South Wales to the Monash substation in South Australia. TEUS notes that the Buronga and Redcliffs substations are a small distance apart and for modelling purposes there is little effect on the gross market benefits given that Murraylink and Alternative 1 and 3 would provide power from the NSW and Snowy-Vic regions into South Australia.

Table 4.4 Gross market benefits of Alternative projects (VoLL = $10,000/MWh) ($millions)

GMB	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Energy	82	77	82	77	65
Merchant entry (capital)	49	49	49	49	39
Merchant entry (O&M)	5.4	5.4	5.4	5.4	4.3
Reliability	62	62	62	62	67
Riverland deferral	22	22	22	22	22
Riverland O&M	19	1.9	1.9	1.9	1.9
TOTAL	**223,**	**218**	**223**	**218**	**198**

Table 4.5 Gross market benefits of Alternative projects (VoLL = $29,600/MWh) ($millions)

GMB	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Energy	82	77	82,446	77	65
Merchant entry (capital)	49	49	49,213	49	39
Merchant entry (O&M)	5.4	5.4	5.4	5.4	4.3
Reliability	183	182	183	182	197
Riverland deferral	22	22	22	22	22
Riverland O&M	1.9	1.9	1.9	1.9	1.9
TOTAL	**345**	**339**	**345**	**339**	**329**

In its submission of 12 August 2003, MTC comments on the losses and MW power delivered of Murraylink and Alternative 3. In figure 1 of its attachment labelled 'comments on treatment of losses', TEUS shows that the actual losses of the Murraylink interconnector are greater than the losses estimated for Alternative 3 up to 180MW power delivered. However, from 180MW, the losses on the AC Alternative 3 option are greater than the losses on the Murraylink interconnector.

The Commission notes that the gross market benefits of Murraylink come predominately from its ability to deliver over 180MW transfer capacity. Furthermore, the gross market benefits of Murraylink have been calculated based on a 220MW transfer capability for Murraylink. Therefore based on the loss equations provided by MTC, the gross market benefits of an alternative AC link would be below the gross market benefits of Murraylink.

The Commission considers that based on the information provided by MTC, the Commission is of the view that the gross market benefits of Murraylink and the alternative projects are unlikely to be materially different in that it will not change the outcome of the regulatory test, and the ranking of Murraylink and its alternative projects.

4.4.6 Conclusion

The Commission is of the view that there are 4 broad types of benefits that Murraylink and its alternatives can bring to the NEM. These are:

- energy benefits;
- deferred market entry benefits;
- reliability benefits; and
- Riverland deferral benefits.

The Commission considers the methodology employed by MTC in the estimation of the market benefits of Murraylink and its alternative projects is not inconsistent with the principles set out in the regulatory test. However, the Commission believes that the Riverland deferral benefits have been overstated by MTC and the Commission has adjusted these benefits accordingly.

The Commission is of the view that the assumption adopted by MTC that the benefits of Murraylink's alternatives are equivalent to the gross market benefits of Murraylink is not appropriate. However, TEUS has provided estimates of the gross market benefits of the alternative projects which shows that the these estimates are not materially different to the gross market benefits of Murraylink. The Commission therefore considers that it is unlikely that the approach adopted by MTC will change the outcomes of the regulatory test and the ranking of Murraylink and its alternative projects.

Commission's Decision

The Commission is of the view that there are 4 broad types of benefits that Murraylink and its alternatives can bring to the NEM. These are:

- **energy benefits;**
- **deferred market entry benefits;**
- **reliability benefits; and**
- **Riverland deferral benefits.**

The Commission has adjusted the gross market benefits for two items:

- **Riverland deferral benefits; and**
- **timing and possible implementation of augmentations to the Victorian network.**

4.5 Market development scenarios and sensitivity analysis

4.5.1 Introduction

The expected net market benefits of the alternative projects depend on the behaviour that is assumed for market participants. As the behaviour of market participants cannot be predicted with certainty and depend on bidding strategies, market development scenarios need to be considered in a regulatory test assessment. Furthermore, due to the nature of modelling, the testing of key input parameters is important to ensure and demonstrate the robustness of the analysis.

The regulatory test requires that market development scenarios be considered under both the reliability and market benefit limbs of the regulatory test. In addition to market development scenarios, the regulatory test specifies that sensitivity analysis should be undertaken to test key input parameters. The regulatory test states that:

> "An *augmentation* satisfies this test if -
>
> (a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or
>
> (b) in all other cases – the augmentation maximises the net present value of the *market benefit*
>
> having regard to a number of alternative projects, timings and **market development scenarios.**
>
> For the purpose of the test:
> …
> (d) the calculation of the *market benefit* or *cost* should encompass **sensitivity analysis** with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis;
> …
> (e) a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) **credible scenarios**; and"

In note 5 and 6, the regulatory test provides some guidance on the type of scenarios that need to be considered in a regulatory test assessment. Notes 5 and 6 state:

> (5) In determining the *market benefit,* the analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project *commissioning* dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative *construction timetables* as nominated by the proponent. These scenarios should include projects undertaken to ensure that relevant reliability standards are met.
>
> These market development scenarios should include:
>
> (a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);
>
> (b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);

(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (*modelled projects*); and

(d) any other projects identified during the consultation process.

(6) Modelled projects should be developed within market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'.

(a) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.

(b) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes"

The role of sensitivity analysis is to test the variability of the gross market benefits to key assumptions. The role of market development scenarios is to capture the uncertainty which necessarily exists about the future 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.

4.5.2 MTC's application

In MTC's application, TEUS provides 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 per cent.

Table 4.6 Gross market benefits market development scenarios ($millions)

Scenarios	Murraylink ($m)	Alt 1 ($m)	Alt 2 ($m)	Alt 3 ($m)	Alt 4 ($m)
Medium Growth (base case)	214	214	214	214	214
Low Growth	136	136	136	136	136
High Growth	226	226	226	226	226

In addition to the development scenarios, MTC presented the sensitivity of the gross market benefits to the discount rate. Deloitte Touche Tohmatsu (Deloitte) was engaged by MTC to determine a discount rate consistent with 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 per cent, with a discount rate for the low and high case of 7.76 per cent and 10.40 per cent respectively. The discount rates and the respective gross market benefits is presented in the table below.

Table 4.7 Gross market benefits – discount rate sensitivities ($millions)

Sensitivities (discount rate)	Murraylink ($m)	Alt 1 ($m)	Alt 2 ($m)	Alt 3 ($m)	Alt 4 ($m)
8.25%	234	234	234	234	234
9.25%	214	214	214	214	214
10.25%	198	198	198	198	198

4.5.3 Commission's Preliminary View

In its Preliminary View, the Commission argued that MTC's approach in calculating a definitive market benefit for Murraylink based on one market development to determine the economic value of the Murraylink interconnector was not consistent with the regulatory test. The Commission also noted that the gross market benefits as calculated under the regulatory test are subject to variability depending on the sensitivity and market development scenarios applied. The Commission was of the view that the sensitivities provided by TEUS do not confirm that the base case is robust but provides an indication that a single gross market benefit is subject to variability depending on the assumptions adopted about the market in a regulatory test assessment.

With respect to the discount rate, the Commission was of the view that the absolute value of the discount rate in a regulatory test assessment is not relevant to the extent that the change in the commercial discount rate does not change the ranking of alternative projects.

4.5.4 Submissions on the Commission's Preliminary View

4.5.4.1 MTC's response to the Preliminary View

Treatment of uncertainty in the estimation of gross market benefits

TEUS notes that its sensitivity analysis provided to the Commission in a submission dated 14 March 2003 indicates that the calculated value of Murraylink's gross market benefits generally increases when the sensitivity parameters are tested. It argues that this demonstrates that the base case estimate is conservative, and that the majority of the sensitivity and scenario analysis provide estimated gross market benefits that lie within plus or minus 10 per cent of the base case estimate.

TEUS also notes that the IRPC Stage 1 Report provides probability estimates and weighting factors that can be applied to the low growth, high growth, and base case to develop a "most likely" gross market benefit estimate. It submits that this information can also be used to infer confidence limits for the gross market benefits.

Using the information from the IRPC Report, TEUS provides calculations to show that the single or expected value of the "most likely" estimate, and a 90 per cent confidence interval for Murraylink's gross market benefits. The results of TEUS' analysis is presented in the table below.

Table 4.8: confidence limits on the "most likely" gross market benefit ($millions)

Confidence limits	Lower bound ($m)	Upper bound ($m)	95% confidence that GMB equal or exceed
90% confidence limit ($10,000/MWh)	173.9	219.6	173.9
90% confidence limit ($29,600/MWh)	245.1	338.7	245.1

TEUS thus believes that the Commission can confidently adopt $207.1m as the best, or most likely estimate of Murraylink's gross market benefits if it believes that $10,000/MWh is the most appropriate measure of the value of reliability. In its submission of 18 July 2003, TEUS notes that using the revised discount rate and commencement date, the expected value of the gross market benefits is $215.5m ($10,000/MWh) and $331.2m ($29,600/MWh).

Optimal timing

ACG concurs that the optimal timing of a project is relevant when applying the regulatory test to the situation for which it was designed, when assessing and ranking the desirability of the set of possible alternative projects. However, it notes that it is not necessary when deriving the regulatory value for an asset using the ODRC methodology. ACG submits that should the Commission wish to take account of the optimal timing of an alternative project to Murraylink, the effect of the optimal timing of –or rather, a potential delay in the in-service date of the optimal replacement asset, can be analysed using the following formula:

$$regulatory\cos t^{ACTUAL} = GMB^{ACTUAL} - \frac{NMB^{OPTIMAL}}{(1+r)^{T}}$$

Value of unserved energy assumption

ACG submits that in MTC's modelling of the market benefits, there are two quite different uses for an assumption about the "value of lost load":

- the first is the level of the price cap expected to apply in the wholesale market in the future, which may affect the level of new generation entry (and related benefits such as the predicted energy savings from interconnection) in the future; and
- the second is the actual loss estimated to be suffered by end-users (ie the loss of consumer surplus) that would result from an outage – which affects directly the estimated benefit to end users from greater reliability.

ACG notes that $10,000/MWh is the appropriate value to be used for the first of these. In terms of the second value, ACG notes that using a value for unserved energy that is greater than the wholesale market price cap when applying the regulatory test may favour network solutions over non-network alternatives However, it notes that as the relevant alternative projects for Murraylink comprise only transmission options, possible distortions in the selection of the optimal alternative to Murraylink would not arise. It also states that while the use of a value of unserved energy is equal to the wholesale market price cap may achieve competitive neutrality between generation and transmission, it would not promote efficient outcomes.

Discount rate

ACG notes that notwithstanding the fact that the discount rate has not been controversial in applications of the regulatory test to date, it is appropriate for the Commission to provide guidance on what it considers is an appropriate magnitude for the discount rate for estimating the market benefits from a project.

MTC's revised discount rate of 9 per cent (in real, pre tax terms) was prepared by Deloitte. The revision in the proposed discount rate reflect two changes, the use of a gamma of 0.5 (rather than 0.45) consistent with the Commission Preliminary View, and also to use real risk free rate and inflation assumptions consistent with the Commission's Preliminary View. The revised gross market benefits submitted by TEUS are set out in the table below.

Table 4.9: Gross market benefit for revised discount rate

		Gross Market Benefits $m			
Assumptions	Value of Unserved Energy	VoLL=10,000		VoLL=29,600	
	Inflation	2.20%	2.11%	2.20%	2.11%
	Commencement date	1/ May/03	1/Sep/03	1/ May/03	1/Sep/03
	Discount rate	9.25%	9.00%	9.25%	9.00%
Gross market benefit results	95% Prob of exceedence	173.9	180.5	245.1	256.8
	Expected value	207.0	215.5	315.5	331.2
	5% Prob of exceedence	219.6	227.8	338.7	354.3

Extended low growth case

TEUS notes that it has extended the market equilibrium balancing process in the low growth case for several more years, as recommended by the Commission's consultant, Saha. It notes that by extending the market balancing process through to 2016, TEUS has developed a more accurate value of the gross market benefits in the low growth case using a 'market equilibrium balancing termination year' where equilibrium market conditions have emerged. TEUS provides the gross market benefits of the extended market balancing process presented in table 4.10.

Table 4.10 Gross market benefit results for extended market balancing process ($millions)

Case	Termination Year	CPW Gross Market Benefits $M
Original low growth case	**2012**	**136.3**
Extended low growth	2013	158.3
	2014	168.6
	2015	169.2
	2016	168.6

4.5.4.2 Submissions by other interested parties

Consistency with regulatory test application

ESIPC submits that there are differences to the methodology applied for Murraylink compared to the methodology applied by TNSPs for the assessment of new assets. ESIPC questions whether it is appropriate to calculate a median market benefit rather than a "most likely" benefits with sensitivities to test the robustness of the conclusion.

In terms of bidding scenarios, ESIPC submits that the SNOVIC and SNI regulatory test applications required that alternative bidding scenarios be used and not just a single SRMC methodology. ESIPC suggests that a LRMC based bidding strategy to model the market creates far more rational results that reflect the true operation of the market. ESIPC highlights that MTC has purported to examine market development scenarios where the price is more reflective of current price outcomes, however this would appear to have been achieved by simply scaling the SRMC value for each generator. ESIPC submits that while this methodology will raise prices it does not re-sequence the generators into a merit order more consistent with the reality and effectively just maintains MTC's forecast level of benefits by scaling the entire market up.

Optimal timing

ElectraNet and TransGrid note that the application of the regulatory test in normal circumstances requires that the proponents optimise the timing of the project, and that the timing will not be earlier than when the project demonstrates positive net market benefits, and should also be applied in the case of Murraylink.

4.5.4.3 MTC's response to submissions by interested parties

In response to concerns raised in submission that the market conditions used by TEUS, in particular whether or not the gross market benefit provided by Murraylink were sensitive to the generator bidding behaviour, TEUS has estimated the gross market benefits of Murraylink under a different set of market conditions by modifying several base case assumptions. It has adopted a LRMC generator bidding strategy using the IRPC Stage 1 Report, and assumed that the reserve trader mechanism operates over the life of Murraylink.

TEUS notes that the introduction of such assumptions generally acts to shift the gross market benefits between the market benefits categories. TEUS also notes that the overall gross market benefits remain above $215 m for the base case economic growth even for a value of residual unserved energy of $10,000/MWh. The LRMC bidding increased Murraylink's energy benefits, and decreased the reliability benefits. It notes that despite higher levels of market entry between the with and without cases, difference in market entry between both cases is small, resulting in lower market entry deferral benefits. Furthermore, valuing unserved energy at $29,600/MWh produced LRMC gross market benefits of $227 million and at $10,000/MWh the gross market benefits were $216.8 million.

4.5.5 Commission's considerations

Discount rate

In response to the Commission's issues paper, a number of interested parties questioned the use of a single discount rate, and noted that MTC has used a commercial discount rate of 9.25 per cent which is significantly lower than that used in other recent applications of the regulatory test. The Commission notes that in previous application of the regulatory test, there has not been a consistent discount rate value adopted. Furthermore, NEMMCO, in its SNI analysis used a real pre-tax commercial discount rate of 11 per cent with sensitivities at 9 per cent and 13 per cent, while VENCorp in its Latrobe to Melbourne study used a pre-tax real discount rate of 8 per cent with sensitivities at 6 per cent and 10 per cent. The Commission notes that the net present value of the market benefits is sensitive to the discount rate adopted, and that the higher (lower) the discount rate applied, the lower (higher) the gross market benefits of the options being assessed under the regulatory test.

In response to the Commission's Preliminary View, MTC revised its discount rate to 9 per cent, with upper and lower bounds of 10.27 per cent and 6.72 per cent respectively. The Commission notes that MTC has adopted a commercial discount rate which falls between the discount rate applied to SNI and that applied by VENCorp in its Latrobe to Melbourne study. The Commission also notes that the amended discount rates are lower than initially proposed by MTC. This has the effect of increasing the net present value of the gross market benefits. However, the Commission considers that the changes in the discount rate do not affect the ranking of Murraylink and the alternative projects and therefore the outcome of the regulatory test assessment.

The Commission noted in its promulgation of the regulatory test in 1999, that the discount rate adopted for the purposes of a regulatory test evaluation should be a commercial discount rate. The Commission stated that:

> "The net present value calculation should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector"[40]

The Commission further states that:

> "In order to ensure that regulated network investments are undertaken in a competitively neutral way in comparison to generation and non-regulated investment, the [Commission] has accepted the argument that a commercial discount rate be used" [41]

As noted in its Preliminary View, the Commission agrees with NERA 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. Given the Commission is applying the regulatory test to Murraylink, it considers that the

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

discount rates provided are appropriate for ranking purposes. Therefore the Commission is satisfied that the discount rates adopted by MTC are appropriate for the purposes of the regulatory test. As such the commercial discount rate for the purposes of the regulatory assessment of Murraylink and its alternatives is 9 per cent with sensitivities at 6.72 per cent and 10.27 per cent.

Value of Unserved Energy

The Commission notes that the regulatory test states that in determining the market benefits, it requires:

> “reasonable forecast of:
> ii the value of energy to electricity consumers as reflected in the level of VoLL;…”

In its promulgation of the regulatory test in December 1999, the Commission provided no guidance on the value attributable to VoLL for the purposes of calculating the value of energy to electricity consumers. Furthermore, the Ernst & Young Final report[42] noted:

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

- that VoLL should be applied consistently between generation, demand and transmission in all benefits analysis; and
- scenarios using both a market-based VoLL ($5000/MWh) and a reliability-based VoLL (eg $25,000) should be assessed and the resulting net benefits should be factored into the ultimate decision on augmentation”

In previous applications of the market benefits limb of the regulatory test, a VoLL of $10,000/MWh, as specified in the code has typically been adopted. In its Latrobe to Melbourne regulatory test assessment, VENCorp tested the sensitivity of the gross market benefits to a variation in the VoLL to $20,000/MWh. However, VENCorp is proposing to use a value of $29,600/MWh for transmission planning purposes.[43] The Commission also notes that in a recent decision by the Victorian Essential Services Commission (ESC) on the economic justification of the recovery from customers of network support payments made to Somerton Power Station (an embedded generator), the ESC accepted the application of VoLL of around $28,000/MWh in a network investment evaluation.

VENCorp has noted in its final report on unserved energy[44] that it interprets the Commission’s reference to the value of unserved energy to consumers, rather than on the wholesale market price cap, and this interpretation is based on note 6(a) of the regulatory test, which states:

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[42] Ernst & Young, Final report to the ACCC, *Review of the Assessment Criterion for New Interconnectors and Network Augmentations,* March 1999.
[43] VENCorp 23 May 2003, *Response to submissions: Final Report. The value of unserved energy to be used by VENCorp for electricity transmission planning.*
[44] Ibid

> "Modelled projects should be developed with market development scenarios using two approaches: 'least-cost market development' and 'market-driven market development'. The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposal to be included would be those where the net present value of benefits, such as fuel substitution and **reliability increases**, exceed the costs".

The Commission is of the view that the current wording of the regulatory test does not specify a value of VoLL to be applied for the calculation of the gross market benefits. The Commission concurs with interested parties that the VoLL specified 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. Therefore, the Commission is of the view that where an appropriate value of customer reliability has been determined for a region or sub-region, it would be not inconsistent with the regulatory test to be used in the calculation of the estimated benefits to end-users from greater reliability. In the absence of an accurate value for the value of customer reliability, the VoLL specified in the code should be used. However, the Commission notes that for the purposes of sensitivity analysis, it is appropriate for different values of VoLL to be tested.

For the purposes of the regulatory test assessment for Murraylink, MTC has assumed a value of $29,600/MWh. The Commission notes that this value is consistent with the Victorian composite value of customer reliability determined by a CRA study commissioned by VENCorp. Furthermore, the benefits that the Murraylink interconnector provides are mainly attributable to the South Australian region, and in particular the Riverland region, therefore the Commission must consider whether a value of $29,600/MWh (an average for the Victorian system) is appropriate to be used to determine the gross market benefits of Murraylink, which provides benefits to the Riverland region. While a value of $29,600/MWh may be appropriate for Victorian customers, the Commission does not have a view as to its appropriateness in the case of interconnector alternatives that are expected to service the South Australian region, and in particular the Riverland region. Therefore the Commission believes that it is not inconsistent with a regulatory test assessment for the value of VoLL to be based on the current market price cap and/or a level of VoLL based on an objectively identified measure.

SRMC and LRMC

The Commission notes that in MTC's application and subsequent submissions, the gross market benefits under the market development scenarios and sensitivities were calculated assuming SRMC bidding by generators. In response to submissions to the Commission's Preliminary View, TEUS provided estimates of the gross market benefits of Murraylink and its alternatives assuming LRMC.

As part of the its review of the regulatory test and in particular competition benefits, the Commission engaged Farrier Swier Consulting.[45] As part of its consultancy, the consultant assessed how proponents have taken into consideration 'least-cost market

[45] Farrier Swier Consulting, Report to ACCC, *An analysis of competition benefits*, July 2003.

development' and 'market-driven market development' approaches under the market benefits limb of the regulatory test.[46] It was noted in that report that:

> " With the exception of the application of the Regulatory Test by TransEnergie for Murraylink, all other cases have projected spot prices on the basis of scenarios that included bids above SRMC (whether called 'LRMC' or 'bids based on what was observed in the NEM'). In all cases, bids were assumed to be fixed for the period of the analysis i.e. they were not assumed to react dynamically to each other as would be expected in a competitive market i.e. no account has been taken of the strategic response of producers to the proposed transmission augmentation under review.
>
> Other than Murraylink's conversion application (which assumed SRMC bids) for all other applications of the Regulatory test where non-SRMC bidding assumptions have been made, Competition Benefits have potentially been counted to the extent that some assessment have been made of how prices are brought closer to SRMC following the augmentation. However, we note that in previous applications of the Regulatory Test there has been no assessment of the way that generators may alter their bids in response to competitive threats brought-on by proposed augmentation. This is likely to miscalculate Market Benefits in any real market where competitors as likely to adjust their bids in response to changes in the market." (p 46)

The Commission notes that since MTC's original application it has provided additional market developments including assessment of the market benefits under LRMC, and generation bids above SRMC. While SRMC and LRMC modelling has been considered in Murraylink and other applications of the regulatory test, actual bidding under note 6b of the regulatory test has not been determined due to the difficulty of modelling such behaviour. As part of its review of the regulatory test and in particular the issue of competition benefits, the Commission is looking at this issue.

The Commission is therefore satisfied that SRMC, generation bids above SRMC and LRMC has been considered in the TEUS assessment of market benefits for Murraylink and its alternative projects.

Extended low growth case

The Commission notes that in response to recommendation by its consultant Saha, TEUS extended the market equilibrium balancing process in the low growth case from 2012 to 2016. TEUS contends that by extending the market balancing approach, it has developed more accurate values of gross market benefits in the low growth case when equilibrium market conditions have emerged.

The Commission notes that extending the equilibrium process for the low growth case has the effect of increasing the gross market benefits for the low growth case from approximately \$136 million to approximately \$169 million. However, while the gross market benefits for the low growth case increase, this does not change the ranking of Murraylink and its alternatives under the regulatory test assessment. Therefore the Commission considers that it is not inappropriate to extend the market equilibrium balancing process for the low growth case to 2016.

[46] Farrier Swier Consulting looked at the IRPC's assessment of SNOVIC 400 and SNI, TEUS assessment of the Murraylink conversion application, VENCorp assessment of the Latrobe to Melbourne upgrade, and TransGrid's assessment of SNI.

Optimal timing

The Commission notes comments by interested parties that the regulatory test requires that the proponents optimise the timing of the project, and that the timing will not be earlier than when the project demonstrates positive net market benefits. ACG however, is of the view that it is inappropriate to take into account the optimal timing of a 'notionally reconfigured system' when deriving the regulatory value for an asset in existence, such as Murraylink.

As the Commission is applying the regulatory test to Murraylink, it is of the view that the optimal timing of Murraylink should be factored into the regulatory test assessment. The Commission notes that the optimal timing of a project is relevant when applying the regulatory test in assessing and ranking the desirability of the set of possible alternative projects. In promulgating the regulatory test, the Commission accepted the principle of optimality to ensure that a proposed investment vying for regulated income, is commissioned at a time that maximises the net market benefits. Such a requirement ensures that networks were limited in their ability to 'gold plate' by undertaking investment at a time that is well before that which could be reasonably justified.

The Commission requested that MTC provide its analysis of the impact of timing on the net market benefits of Murraylink and its alternatives. The Commission notes that the gross market benefits of Murraylink and its alternative projects, based on information from MTC, at different commissioning dates are presented in Appendix F of this Decision.

The tables in Appendix F shows that the gross market benefits are optimal at around 2003. Therefore the Commission is of the view that as Murraylink and its alternative project are optimal at 2003, the gross market benefits will not need to be reduced, except for the amendments proposed by the Commission in the gross market benefits section of this chapter. The net market benefits of Murraylink and its alternative projects are presented in the Commission's assessment of the net benefits and ranking of alternatives section, and in Appendix G.

Sensitivity Analysis, Market development scenarios, and treatment of uncertainty

The Commission notes that in response to its concern expressed in the Preliminary View regarding the uncertainty prevalent in estimating a single value of gross market benefits in a regulatory test assessment, MTC performed confidence interval estimates to demonstrate that it is appropriate to adopt a single value or expected value of the 'most likely' estimate. The Commission also notes concerns expressed by ESIPC which questions the calculation of a median market benefit rather than a "most likely" benefits with sensitivities to test the robustness of the results.

The Commission notes that the regulatory test requires that both market development scenarios and sensitivity analysis be considered as part of a regulatory test assessment to test the robustness of the analysis to input parameter variability and behaviour of market participants. Furthermore the regulatory test does not refer to estimating a "most likely" or "median" estimate of the gross market benefits, but makes reference to the augmentation or proposals being assessed maximising the market benefits (that is the gross market benefits minus the costs) in most credible scenarios. Part (e) of the regulatory test states:

> "(e) a *proposed augmentation* maximises the *market benefits* if it achieves a greater *market benefit* in most (although not necessarily all) credible scenarios;"

The Commission considers that it is inconsistent with the regulatory test to derive a "most likely" or "median" estimate of the gross market benefits, given that it does not make reference to such outcomes.

The gross market benefits of Murraylink and its alternative projects under different market development scenarios and sensitivities are presented in Appendix F.

4.5.6 Conclusion

Commission's Decision

Taking into consideration the comments of interested parties, and the sensitivity analysis and market development scenarios provided by MTC, the gross market benefits of Murraylink and Alternatives 1, 2 and 3 range from $166 million to $347 million, and the gross market benefits of Alternative 4 ranges from $169 million to $350 million. The market simulation suggest the most credible range is between $170 million to $220 million.

4.6 Cost of alternative projects

4.6.1 Introduction

A regulatory test assessment requires the cost of an augmentation and its alternatives to be considered. In particular, the regulatory test states that:

> (3) The costs identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost. Any other costs should be disregarded.
>
> (4) In determining the *market benefits,* any benefit or costs which cannot be measured as a cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the *Transmission Ring-Fencing Guidelines* and/or *Distribution Ring-Fencing Guidelines* (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

This section compares the costs of alternative projects with Murraylink. This comparison is necessary for two reasons. The first is that the Commission must determine whether Murraylink and its alternatives will deliver net present value of the benefits to the market, that is gross market benefits less the lifecycle operating costs. The second is that the cost of the option that maximises the benefits to the market will be used as the regulatory asset value for the purposes of setting MTC's MAR.

4.6.2 MTC's Application

MTC notes with respect to the alternatives, 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.

The cost of the alternative projects proposed by MTC is outlined in the table below.

Table 4.11: MTC proposed cost of alternative projects ($millions)

Item description	Alternative 1	Alternative 2	Alternative 3	Alternative 4
DEVELOPMENT WORKS				
- Project management	2.2	2.2	2.2	2.2
- Feasibility consultants (legal, market, technical, environmental)	1.3	1.3	1.3	1.3
APPROVALS				
- Planning and environment	2.5	2.0	2.0	2.0
- Regulatory – NEC, ACCC, transmission licence	2.3	2.3	2.3	2.3
- Other – easements, licences, financiers, insurance	7.5	5.4	5.8	6.8
TOTAL DEVELOPMENT COSTS	**15.77**	**13.2**	**13.6**	**15.1**
TRANSMISSION LINE WORKS				
- Design	0.2	0.2	0.2	0.3
- Construction	34.6	20.5	29.1	6.3
- Fabrication	6.8	4.7	5.8	9.2
- Erection	3.9	2.7	3.4	5.3
- Stringing	3.6	2.6	3.1	4.8
- Materials	40	22.3	33.2	12
TOTAL TRANSMISSION LINE COST	**88.1**	**53**	**74.7**	**37.9**
SWITCHYARD WORKS				
- Design	2.2	0.6	1.0	2.9
- Construction (site labour and	5.3	1.5	2.6	6.8
supervision)			6.9	21.3
- Plant	14.9	3.8	0.2	0.7
- Commissioning	0.6	0.1	0.4	1
- Project management	0.8	0.2		
- Phase shift transformers (1x220/132kV 350 MVA combined transformer/PST)	19.1		19.1	19.1
- Static Var compensators (1x +120/-110MVAr)	19.1		18	19.1
_transformer	6.4	15.9		10.1
series cap/DC converter Station		48.7		6.4
- 132kV connection costs (Monash)	10.4	10.4	10.4	10.4
TOTAL SWITCHYARD COST	**78.6**	**81.2**	**58.6**	**98.2**
TOTAL EPC PROJECT COST including P & O	**183.4**	**147.6**	**146.5**	**149.7**
INTEREST DURING CONSTRUCTION	36.4	29.3	29.3	30.1
TOTAL PROJECT COST	**235.5**	**190.2**	**189.4**	**194.9**

Taking into account the contingency and cost of the life-cycle opex cost of the alternative projects the total net present value of the costs are outlined in the table below.

Table 4.12: MTC proposed regulatory costs ($ millions)

	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Base Cost	$235.5	$190.2	$189.4	$194.9
Contingency	$10.4	$16.1	$12.2	$7.1
Total Capital Cost	$245.9	$206.3	$201.6	$202
Opex Costs	$3.6 per annum	$3.4 per annum	$3.5 per annum	$3.6 per annum
Opex net present cost over 40 years	$39.9	$37.7	$38.8	$39.9
Total net present cost	$285.8	$244	$240.4	$241.9

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 stated that undergrounding enables the Murraylink cable to be secure and reliable, and not susceptible to lightning, accidental vehicle damage or vandalism. MTC advised 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 or visual impact, and with no ground current and minimal electromagnetic fields. MTC stated that, as a consequence, the environmental and community impacts of Murraylink are far less than those which would have resulted from the construction of conventional overhead transmission lines (either HVAC or HVDC).

MTC also advised that the undergrounding of Murraylink provides a number of features which enabled the timely construction, environmental permitting, and cooperation with local citizen 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 also 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.[47]

KBR's letter to BRW, 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."

As KBR notes in the same letter, a Joint Advisory Panel appointed by the Commonwealth, Victorian and Tasmanian state governments, reviewed the

[47] Letter from KBR to BRW, 16 October 2002.

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; and

- 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.

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.

4.6.3 Commission's Preliminary View

The Commission considered that the configuration of the alternative projects presented by MTC was based on alternatives that would provide the exact same level of technical service as Murraylink. The Commission did not believe that this was appropriate and therefore deducted elements which it considered were based on providing controllability to the transmission assets. As a result the Commission adjusted the cost of the alternative projects to reflect the removal of undergrounding, PSTs and associated spares.

In line with the recommendations of its consultant, the Commission thought it appropriate to include an allowance for contingency, based on a P50 approach and for profits and overheads of 10 per cent.

However, due to the removal of the undergrounding provisions and the PST, there was an associated reduction in the allowance for interest during construction and profit and overheads.

With regard to undergrounding, the Commission concurred with MTC's proposed undergrounding for Alternative 1, but did not believe that undergrounding would be required for Alternatives 2 and 3. The Commission therefore, as part of its Preliminary View, disallowed the undergrounding proposed by MTC for these projects.

The Commission's Preliminary View on the costs of the alternative projects are outlined in table 4.13. Based on the Commission's adjustments to the cost of the alternative projects, it found that Alternative 3 maximised the net market benefits under the regulatory test with a regulatory cost of $131.37 million, based on a capital cost of $114.42 million and life-cycle opex costs of $16.95 million.

Table 4.13 Regulatory cost of alternative projects ($ millions)

	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**

4.6.4 Submissions on the Commission's Preliminary View

4.6.4.1 MTC's response to the Preliminary View

As noted in the power transfers section MTC argues that without PSTs, the power transfers of Alternative 3 are unlikely to exceed 140MW. It therefore argues that a PST, and its cost, should be included into the cost of the alternative projects as a PST enables the alternatives to provide the exact same level of technical service as Murraylink.

In regard to the contingency allowance, MTC engaged an expert to assess the appropriateness of the application of a contingency allowance to the alternative projects. Its expert concluded:

- the cost estimates for the alternative projects do not adequately allow for risks associated with changes in scope;
- owners risks are not adequately covered; and
- a P50 risk assessment would be appropriate for a clearly defined scope of works.

Based on this analysis MTC proposes an additional allowance for owners risk to account for potential extensions of time, force majeure, foreign exchange and other variations costing $5.2 million for Alternatives 1 and 3 and $6.2 million for

Alternative 2. Alternative 2's owner's risks were proposed to be higher due to the additional risk associated with foreign exchange movements. MTC also proposes that contingency allowance are based on a P50 risk level rather than P75, as submitted in its initial application.

Undergrounding

MTC maintains that the probabilities that environmental impact mitigation measures such as undergrounding would be required to address environmental requirements should be considered and applied to the overall cost of the alternative projects.

As part of its response to the Commission's Preliminary View, MTC engaged BRW's parent firm, Worley, to reassess the need for major environmental impact mitigation measures in the alternative projects. MTC also engaged BRW to incorporate the results of Worley's analysis into its costing model for alternative projects.

Worley gained input into its assessment of the likely environmental impact mitigation measures required for the routes of the alternative projects through a workshop involving a range of experienced environmental and government assessment advisors, community advocate and industry representatives. Based on a Monte Carlo simulation of the workshop outcomes, the detailed probabilistic assessment resulted in an increase in total capital costs ranging from \$12.7 to \$15.5 million when compared to the level of mitigation measures based solely on undergrounding.

MTC also contends that the New Zealand ODV Handbook referred to by the Commission in its Preliminary View does not prescribe a legal requirements test with regard to the inclusion of undergrounding.

MTC's interpretation of the handbook was that where the asset owner faces a contractual or legal obligation to underground, the cost of undergrounding should be included.

According to MTC, no legislation or government policies in any of the relevant jurisdictions explicitly mandate when and what major environmental impact mitigation measures will be required in transmission projects. MTC states that the necessity for specific measures required for each particular project is largely dependent upon the outcome of community consultation and environmental assessment processes and therefore, approval bodies are unable to provide definitive rulings as to the outcomes before completion of those processes.

MTC cites Basslink as an example, and explains that the environmental assessment and approvals process involved three key outcomes. Firstly, the Basslink Joint Assessment Panel decided that 6.5km of undergrounding along the coast was appropriate, mainly on the basis of mitigating adverse visual impact. Secondly, the Minister for Planning accepted the Basslink Joint Assessment Panel's recommendation, and thirdly, the Minister for Environment issued the *Coastal Management Act 1995* (CMA) consent based upon the Minister for Planning's assessment. It is important to note that according to MTC, the CMA consent had nothing to do with the issue of undergrounding on the coastal plain.

4.6.4.2 Submissions from other interested parties

The submissions received by the Commission focused predominantly on the cost of Alternative 3, given that a modified Alternative 3 was selected by the Commission for the purposes of setting MTC's opening asset valuation.

Cost of Alternative 3

The ESIPC engaged Western Power to consider the cost of a range of alternative projects. Based on Western Power's findings, it argues that the costs of the alternative projects are closer to around $57 million. It notes that the primary differences between its results and those of BRW are:

- the removal of undergrounding costs. Without these costs, the line costs for both sets of figures are not significantly different;
- the non-inclusion of significant spares (facilitated by redesigning substation works to allow for standard rather than custom-built transformers);
- choosing different component item rating sizes commensurate with power transfer capacity; and
- the non-inclusion of interest during construction.

The SA Minister for Energy proposes a cost for Alternative 3 of $77 million. He notes that this cost difference is primarily driven by the removal of a PST, in line with the Commission's Preliminary View, as well as the SVC and an allowance from the Monash substation. He also recommends that profits and overheads be deducted from the Commission's allowance.

The NSW Minister for Energy engaged SKM to conduct a review of the cost of alternative 3 with the exclusions identified by the Commission in its Preliminary View. Its finds that the cost of Alternative 3 should be $72 million. The differences from the Commission's costings arise from using a smaller per unit cost rating for transmission lines, a smaller allowance for easements, a reduction in the substation allowance and a reduced provision for interest during construction.

The costs proposed by the ESIPC, the SA Minister for Energy and the NSW Minister for Energy are presented in the table below.

Table 4.13: Summary of capital costs of alternative 3 submitted by interested parties ($millions)

Cost categories	MTC's Application	ESIPC	NSW Minister for Energy	SA Minister for Energy
Total development costs	13.6	0	5.4	13.6
Total transmission line costs	74.7	29	24.8	28.6
Total switchyard costs	58.6	23.5	30.8	17.5
Total cost	**146.8**	**52.5**	**61**	**59.7**
10% profit and overhead	13.3	5.2	Included above	4.6
Interest during construction	29.3	0	4.5	12.3
P50 contingency costs	6.9	0	6.9	0
Total project costs	**196.3**	**57.8**	**72.5**	**76.5**

ElectraNet and Powerlink argue that in general, the costs of the alternative projects appear high. In particular, they recommend that interest during construction be set at 7.5 per cent instead of 14 per cent and that the Commission should not allow the 10 per cent allowance for contractor profit and overheads and not a separate contingency allowance for the purpose of valuing alternative projects.

ElectraNet also notes that MTC chose to build and fund a greater proportion of the Monash substation to expedite its construction and maximise Murraylink's deliver to market and as a result the Monash 132 kV connection costs should be reduced to approximately $6-7 million.

Allowance for Spares

ElectraNet and the ESIPC disagree with MTC's allowance for spares.

The ESIPC states that network spares normally represent the list of equipment necessarily kept on hand to restore power in the event of the failure of a critical piece of plant. As a result, it suggests that there are alternatives to maintaining spares:

- standardise equipment - where possible, NSP's endeavour to use standard equipment across a network;
- sharing of spares - where there are multiple network elements of a single "type", it is common to have only one (or one per X network elements) spare that is shared; and
- cross-NSP spares - where a single line is being built by a third party with no other network assets, a scheme whereby spares are shared between NSPs.

Regarding the need for a spare PST, ESIPC argues that in terms of restoring services, a normal transformer would satisfy the South Australian Transmission Code for a category 3 area such as the Riverland. It notes that while flows and control may not be as optimal as those with the PST, they are likely to be sufficient to maintain supply and satisfy reliability requirements until a replacement PST can be sourced.

ElectraNet argues that the level of spares allowed are not in accordance with industry practice and should be based on around 1 per cent of asset value in total.

Cost of voltage support

As noted in the power transfers section, ElectraNet, in consultation with VENCorp, proposes a number of alternatives to the installation of a +120/-110 MVA SVC at Monash to rectify voltage fluctuations. The cost of its alternatives are:

- $5 million (excluding spares) for the installation of a smaller 35 Mvar SVC facility at Monash substation;

- $5 million (excluding spares) for the installation of 40 Mvar TSC's at Monash substation; and

- $2 million (excluding spares) for the establishment of a bypass circuit breaker across the PST to limit voltage variations.

Augmentations to support the interconnector

VENCorp notes that the costs of the augmentations to the Victorian network to support the interconnectors are approximately $15 million. VENCorp cost estimates are based on/subject to the following:

- the estimates are budget estimates only (August 2003 $ exclusive of GST), with an error margin of +/- 25 per cent;
- the estimate represent capital costs only. The estimated annual opex allowance would be in the order of 1 to 1.4 per cent of capital costs;
- the estimates are based on desktop analysis only and preliminary liaison with suppliers; and
- no foreign exchange variations have been factored into the estimates.

Undergrounding

Mildura Rural City Council and Karlene Maywald MP made submissions in support of MTC's decision to underground Murraylink, thereby ensuring that there is no visual or adverse impact on local communities and the environment. The Mildura City Council notes that the only public opposition to the Murraylink proposal was in relation to the Red Cliffs converter plant being located in close proximity to residential buildings. According to the Mildura City Council, had the project been implemented using an overhead cable transmission option, it believes there would have been significant issues with the general community, town planning and environmental approvals through the Murray Sunset National Park en-route to South Australia. However, Mildura City Council also notes that an above ground proposal may today require an Environmental Effects Statement from the Victorian Government.

Powerlink suggests that if the Commission was to reintroduce “tactical undergrounding” into the regulated asset value proposed for Murraylink, it would establish a precedent that it is permissible to include tactical undergrounding in cases where there is no legal requirement. According to Powerlink, the Commission’s Preliminary View will also set a benchmark for the degree of tactical undergrounding that represents the lowest cost solution for a remote rural environment such as that traversed by Murraylink or the alternative overhead solution.

Victorian Department of Sustainability and Environment

The Victorian Department of Sustainability and Environment (DSE) provided information in support of MTC’s decision to underground the transmission cable. DSE’s advice covered three main areas: the decision of the Minister for Planning; the management of the approvals process within the planning provisions of the Mildura Rural City Council; and the relevance of the *National Parks Act 1975*. According to DSE, the Minister for Planning determined, on 7 February 2000, that an Environment Effects Statement was not required for the Murraylink Project. The Minister was satisfied that an alternative Environment Report, not prepared under the formal provisions of the Act, was sufficient. The project could therefore be approved pursuant to Section 55 of the *Planning and Environment Act 1987,* for which the Mildura City Council was the responsible authority.

According to the DSE, the proposal for Murraylink avoided the need to place infrastructure in a National Park. DSE makes the point that had Murraylink applied for permission to lay an underground powerline or overhead powerlines through the Murray-Sunset National Park, Sections 27 & 27a of the *National Parks Act 1975* would have applied. DSE points out that since the manner in which the cable was laid, that is, in the verge between the roadside and the Park’s boundary, did not require Murraylink to seek approval under the relevant clauses of the *National Parks Act 1975,* one can only hypothesise as to how the minister responsible for the aforementioned Act would have responded to an application that had been made. Nevertheless, according to DSE, the potential to avoid the use of overhead powerlines was relevant to the Minister for Planning in making a decision on the need for an Environment Effects Statement.

DSE articulates the various precedents that the laying of the underground cable by Murraylink has set. For example, the underground alternative to overhead powerlines is considered viable and, by working closely with local planning authorities, network owners are able to minimise the impact on the environment. It is also noted that Murraylink has participated in the development of technology to allow the cables to be laid in an easement of three metres or less. DSE states that the only logical approach is to have underground powerlines for at least part of the length between Red Cliffs and the South Australian border because there does not appear to be sufficient width to allow the installation of overhead lines outside of National Parks.

Submissions made in response to the Department of Sustainability and Environment letter

Environmental impact

ElectraNet states that, in developing transmission lines, decisions are made balancing the environmental and other impacts on affected parties with the economic delivery of essential services. Historically this has meant underground solutions have only been implemented in high-density urban areas.

ElectraNet states further that one can only hypothesise as to how the relevant Minister would make his decision to enter into an agreement under section 27 or 27A of the *National Parks Act 1975*. However, according to ElectraNet, Alternative 3 does not traverse any areas which preclude agreements under Section 27A. The closest reference areas are Millewa and Morkalla, which are approximately 10 kilometres to the North and South respectively.

ElectraNet states that the boundary of the nearest wilderness zone is at least 35 kilometres south of the route. Given that the Sturt Highway, the principal corridor for East-West traffic between South Australia and New South Wales, already traverses this area of the National Park it is not obvious that an overhead powerline would "substantially affect" the park. ElectraNet goes on to state that in any event the affected portion of the National Park is a maximum of only 12.5 kilometres in length (in the case of Alternative 3).

Western Power contends that the environmental impact may in some cases be greater with underground cables. For example, in sensitive areas such as those affected by threatened ecological communities or threatened species it may be more acceptable to span across the sensitive area with an overhead line because the underground alternative may in fact have a more adverse impact upon the area as a result of trench excavation. It is also generally possible to develop reasonable low impact overhead transmission line options.

Legislative considerations

The DSE's submission makes the point that we can only hypothesise as to how the relevant Minister would make his decision to enter into an agreement under Section 27 and 27A of the *National Parks Act 1975*. ElectraNet concurs that this is a matter of conjecture.

ESIPC submits that even if MTC's requirement to comply with the various planning and environmental legislation is reduced simply by not using overhead lines, it does not necessarily follow that overhead powerlines would not be possible. According to ESIPC, it would simply be more difficult to satisfy the legislative requirements.

Precedents established by undergrounding

According to ESIPC, the technical viability of underground cables has been known for quite some time and is used in most Australian capital cities. ESIPC states that it is the financial viability that is the main point of contention. Given the estimated earnings of Murraylink and, according to ESIPC, its willingness to convert to a regulated income at a level significantly less than the capital cost of the asset, it would appear to demonstrate that underground cables may not be viable.

ElectraNet also responds to the DSE’s statement that Murraylink has established that the undergrounding of high voltage powerlines is viable and that it would impact future planning decisions in relation to overhead powerline developments in Victoria. According to ElectraNet, Murraylink has built a substantial powerline underground but not necessarily at a cost which a reasonable person would consider prudent or be willing to pay. Murraylink has proven that it is technically feasible to underground high voltage powerlines, but not that it is appropriate or prudent in this case.

ElectraNet believes that if the Commission accepts “strategic undergrounding” in rural and remote areas as prudent then ElectraNet expects that this will flow through into the cost of future transmission projects and future valuations of TNSPs’ regulated asset bases.

TransGrid states that a condition requiring a transmission line to be undergrounded for environmental reasons is extremely unusual in Australia. TransGrid believes that this position has not changed and rejects any suggestion that the undergrounding of Murraylink sets any precedents.

The SA Minister for Energy comments that although undergrounding may be technically feasible in regards to lowering visual and environmental impact, the significant increases in costs associated with undergrounding must also be taken into account. In his submission, the Minister concludes that, should undergrounding become the precedent for transmission development, consumers will face large increases in the cost of energy in the future.

Is undergrounding justified?

ElectraNet does not believe that the matters raised and opinions expressed by the DSE are sufficient to justify the readmission of a “strategic undergrounding” allowance in the cost of alternatives for Murraylink as set out in the Commission’s recent Preliminary View.

According to Western Power, DSE’s statement that "the underground alternative to overhead power lines is viable" is not qualified or justified in any way. Western Power contends that it is usually possible to find alternative lower cost overhead options that also minimise environmental impacts such as impacts on high conservation value areas. Furthermore, Western Power contends that the use of underground cable is simply the application of existing technology at significant cost.

Western Power also makes the point that it has successfully obtained approvals from the WA Environment Protection Authority to traverse transmission lines through WA National Parks based upon negotiated outcomes. These include configuring the lines to avoid major vegetation clearing and providing high conservation value properties as offsets.

TransGrid urges the Commission, in its application of the regulatory test to Murraylink, to not limit the alternative network projects to those which include undergrounding transmission lines, but rather to include projects which deliver similar services to Murraylink using overhead transmission lines.

ESIPC states that it would expect that the selection of the route for overhead transmission lines would be carefully chosen with due consideration given to planning and environmental requirements. According to ESIPC, where, for example, difficulties arise between Red Cliffs and the SA Border, a route from Buronga in NSW could be considered. Furthermore, Planning SA in its consideration of SNI identified a viable route for an overhead transmission interconnector.

4.6.4.3 MTC's response to submissions by interested parties

Regarding the costing s suggested by the ESIPC, MTC believes that the alternatives put forward by ESIPC are not technically or environmentally feasible and are significantly underestimated.

MTC reiterates the need for a PST based on the benefits that a PST delivers and the fact that it provides the exact same level of service as Murraylink.

As noted in the power transfers section, MTC argues that only ElectraNet's first solution, with additional switched capacitors, is a suitable alternative to address the Riverland voltage profile but would not provide an equivalent service to Murraylink. It estimates that the installed cost of this alternative is around $13.8 million, including spares. This comprises $11 million for the SVC an associated spares, and $2.8 million for the switched capacitor banks.

MTC argues that the allowance for spares is prudent and should not be considered by the Commission as setting a new benchmark for TNSPs in the NEM. It argues that each TNSP must make an assessment of its spares based on the requirements of the network considered.

In response to the ESIPC comments that a spare standard transformer is appropriate, MTC argues that the South Australian Transmission Code specifically requires that a spare PST be kept. Further it notes that even if a spare standard 220/132kV transformer was compliant with the South Australian Transmission Code, due to the existing network configurations, there are currently no such transformers in the NEM for a TNSP to enter into a partial arrangement for the shared use of that spare with another TNSP.

4.6.5 Commission's considerations

The Commission notes that Saha in its memorandum to the Commission of 26 May 2003 identified an arithmetic error in table 3.7 of its report to the Commission. The error that had occurred was that the costs in the "without undergrounding" cases were overstated and included a double counting of 10 per cent profit and overhead.

The amendments, provided in Saha's memorandum have been incorporated in the Commission's calculations of the costs of Murraylink's alternatives projects.

Phase Shifting Transformers

Based on the information available to the Commission at the time of its Preliminary View, it did not believe that a PST was required to facilitate power system transfers. However, as stated in the power transfers section, the Commission notes the work undertaken by MTC and VENCorp supporting the need for a PST for Alternatives 1 and 3. Based on this evidence, the Commission considers that the cost of a PST should be included in the cost of Alternatives 1 and 3. However, a PST will not be included in the cost of Alternative 4.

Spares

The Commission notes that MTC cites the South Australian Transmission Code for included a spare PST. The South Australian Transmission Code requires that in the case of the Monash – Berri substations, which are considered category 3 loads, that the network is constructed to N-1 standards such that:

> A transmission entity shall keep in stock at least one spare transformer capable of replacing the installed transformer capacity In the event of a transformer failure, a transmission entity will use its best endeavours to repair the installed transformer or install a replacement transformer within 4 days of the failure.[48]

In line with the views of the ESIPC, the Commission believes that in the event of a failure of a PST replacing it with a standard 220/132kV transformer would comply with the requirements of the South Australian Transmission Code. While the Commission agrees with MTC that the flows and control are unlikely to be as optimal as those with the PST present, based on the information presented, it believes that a standard 132/220KV transformer should be sufficient to maintain supply and satisfy reliability requirements until a replacement PST can be sourced. The Commission has therefore only made an allowance for a spare standard transformer in line with the requirements of the South Australian Transmission Code in Alternatives 1 and 3. MTC has advised that the cost of a standard transformer is approximately $2.53 million. The Commission consider this to be reasonable.

More generally, the Commission considers that the general allowance for spares at 1 per cent of switchyard costs would be more than sufficient to cover any contingency events. Further the Commission has made an allowance of 1 per cent for spare SVCs. The Commission believes that this is in accordance with good industry practice.

Cost of voltage support

ElectraNet supports the need for an SVC, or its equivalent for Alternatives 1, 3 and 4. However, ElectraNet has proposed a number of alternative options to providing voltage control to those proposed by MTC. In its subsequent response MTC appears to concur with ElectraNet's alternatives, but suggests that some additional shunt reactors are required to provide Alternatives 1, 3 and 4 with the "exact same level of service" as Murraylink with a total cost of $13.8 million. The Commission's assessment has not been made based on Murraylink's capability but based on the needs of the market as required by the regulatory test. Based on the information

[48] South Australian Transmission Code – Category 3 loads

presented by both MTC and ElectraNet the Commission believes that a cost of around $6 million would appear to be reasonable in the Alternatives 1, 3 and 4 for voltage support. This figure is derived from ElectraNet's proposed cost of SVC and providing an allowance of $1 million for spares as noted above and the installation of the SVC.

Monash substation works

Following further discussions with ElectraNet, the Commission does not believe it appropriate that it make any deductions to the cost of the Monash substation as recommended by ElectraNet and the SA Minister for Energy. The works undertaken by MTC on the Monash substation for the Murraylink interconnector, while being expedited would have been required irrespective of whether there was an interconnector between either Red Cliffs or Buronga and Monash, or alternatively an augmentation between Robertstown and Monash.

Contingency allowance

The Commission still believes that an allowance for a contingency is appropriate when costing augmentation options. It notes that a contingency allowance was made in the IOWG's assessment of the SNI options[49].

The Commission does not believe that it is appropriate to allow the additional costs recommended by MTC's experts because the Commission believes that costs used in the calculation of the transmission lines and switchyards contain a sufficient allowance to cover any cost overruns. Further, changes in the scope of projects should be sufficiently covered by the contingency allowance.

The Commission notes that Worley[50], on behalf of MTC, noted that the calculated contingencies at the P50 and P75 levels from the probabilistic cost estimates for 3 alternative projects are:

Table 4.14: Worley- probabilistic cost estimates for alternative projects

	Alternative 1	Alternative 2	Alternative 3
P50 Contingency	2.1%	3.5%	3.7%
P75 Contingency	4.4%	8.5%	6.5%

BRW in turn used the above probability cost estimates to calculate the contingency allowance for the alternative projects. The contingency allowance was calculated as the base estimate/total project cost of the alternative projects multiplied by the P75 contingency percentage for each of the alternative projects.

The Commission has adopted the same probabilistic cost estimate for each of the Alternative projects. For Alternative 4, the Commission has adopted an average of contingency percentage figures from Alternatives 1 to 3. However, the Commission

[49] IOWG Technical Issues and costs of Interconnector Options for South Australia, 11/5/1999
[50] Worley, on behalf of MTC, *Determination of contingency in capital cost estimates for major resource industry projects*, attachment to MTC submission of 28 February 2003.

has adopted a P50 contingency allowance, which is consistent with Saha’s recommendations. Furthermore, the Commission considers that the contingency allowance should be incorporated into the cost of the alternative, but be provided based on transmission line costs and switchyard works, rather than total project cost (which includes IDC, 10 per cent profit and overhead allowances) as proposed by MTC.

Undergrounding

The Commission has considered the additional detailed information on undergrounding provided by MTC in response to the Preliminary View, and has reviewed the methodology developed by MTC to quantify the capital cost associated with various environmental mitigation measures. The methodology developed by MTC included the formulation of an expert panel to workshop and develop consensus regarding the appropriateness of various environmental mitigation measures and their associated costs.

However, the Commission believes that the better process for assessing the likelihood of various environmental impact mitigation schemes being required is to consider the views of the relevant planning bodies for the states involved, Planning SA and the DSE. Both organisations have made submissions to the Commission which have been taken into account in arriving at its decision on the issue of undergrounding of the alternative projects. The experience of transmission network planners is also highly relevant in this regard.

The Commission maintains its stance in the Preliminary View that the application of the regulatory test is the most appropriate methodology in determining the capital structure upon which the MAR is based. The Commission again points to the information provided by Planning SA which indicates that it is not unreasonable to assume that MTC may in fact have gained approval for overhead lines if it had rigorously pursued other avenues or approval processes.

As stated in its Preliminary View, the Commission notes Saha’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. The Commission also notes the fact that Saha concluded that the cost of the alternative projects, as specified by MTC, relied on KBR’s advice on the “most likely” amount of undergrounding.

With regard to MTC’s use of the Basslink case as an example of undergrounding, the Commission highlights two important factors. Firstly, the Basslink Joint Advisory Panel explicitly indicated that there is no legislative requirement or government policy requiring undergrounding. Secondly, the Panel stated that undergrounding was warranted only in specific situations for particular sections (of the Basslink route) to mitigate adverse visual impacts.

Legislative considerations

The Commission has considered the submission made by the DSE and concurs with the view of interested parties that it is not unreasonable to assume that a proponent for an overhead powerline could reach agreement with the relevant Minister under Sections 27 and 27A of the *National Parks Act 1975*. As noted above by ElectraNet, the proposed route for Alternative 3 does not cross designated wilderness or reference areas that would preclude agreement. Further, the Commission notes the KBR consultancy commissioned by MTC and its comments regarding the absence of legislative or policy requirements for undergrounding.

Precedents established by undergrounding

The Commission does not believe that the undergrounding of Murraylink has created a precedent. The Commission agrees that “strategic undergrounding” through certain sensitive areas may be required as evidenced by the Basslink example, or through the CBD areas of major cities. In the Basslink case, 6.5 kilometres of underground cable was laid across a section of the coastal plain to mitigate adverse visual environmental effects. However, the regulatory test is used to determine the most efficient capital configuration of the asset, which may or may not include undergrounding. Hence, the Commission believes that the main precedent to be established through this process is the manner in which the regulatory test has been applied rather than the particular technical features of the network under consideration.

Environmental impact

The Commission recognises the growing concern about the construction of above ground high voltage transmission lines. In response to its Preliminary View, the Commission received a number of submissions from Queensland residents who oppose the construction of above ground transmission lines. Whilst the Commission notes those concerns, it believes that the regulatory test as applied by it in the circumstances accounts for all relevant factors, thus enabling the Commission to arrive at an appropriate asset base configuration.

It is important to note however, that in the construction of Alternative 1 (as applied under the regulatory test), the Commission has allowed for undergrounding for part of the route. In arriving at this conclusion, the Commission has taken into consideration advice from Planning SA that an overhead transmission line through the Bookmark Biosphere would be questionable from an environmental perspective.

Is undergrounding justified?

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 points out that it has a number of active line projects that have generated actual, not potential, community calls for undergrounding. Powerlink is currently proceeding with the projects as overhead lines (as originally specified) but suggests that a finding in favour of undergrounding here would change its approach to those projects.

KBR reviewed the four transmission line alternatives proposed in order to provide advice on potential undergrounding requirements to address various environmental and social issues, and to achieve the required statutory approvals from each State and the Commonwealth. KBR's advice on the "most likely" requirement for undergrounding of Alternative 3 included 25km based on traversing the settlements at Red Cliffs (Vic) and Lyrup (SA). Undergrounding the line through the Sunset National Park (Vic) was not included as a "most likely" requirement. As noted earlier, Planning SA has commented that the line between Red Cliffs (Vic) and Monash (SA) may not require undergrounding at all.

Clearly, there are wildly divergent 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 provided sufficient imperative to develop Murraylink as an underground cable. The Commission considers that whilst it may have been difficult to obtain approval for an overhead line, sufficient evidence has not been presented to show that such approval could not be obtained.

Views/approaches of relevant authorities

Planning SA

The Commission received advice from Planning SA 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.[51] 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

[51] Refer to Appendix B.

river crossings for Murraylink was part of MTC's development application, and not a requirement of any approval.

Victorian Department of Sustainability and Environment

As previously noted, the DSE submission stated that undergrounding was the only 'logical' solution for part of the Alternative 3 route, citing various processes including the decision of the Minister for Planning, the management of the approvals process within the planning provisions of the relevant City Council and the relevance of the *National Parks Act 1975*.

Given the differences in opinion submitted to the Commission, the Commission finds it difficult to conclude that undergrounding would be a necessary element of Alternative 3 when overhead lines are overwhelmingly used throughout the NEM, including Victoria where the Murray Sunset National Park is situated.

Joint Advisory Panel (Basslink)

The Joint Advisory Panel noted in its consideration of undergrounding:

> "No specific statements of public policy exist either in Victoria or Tasmania to indicate that extremely high powered transmission lines must be underground particularly in rural or expansive areas."

According to the Panel, the cost difference between the installation of underground cables and overhead transmission lines is estimated to be approximately an additional $70 to $90 million for the Victorian land area alone.

The Panel thus concluded that complete undergrounding of the Victorian land section was not justified. However, the Panel also recognised that undergrounding could be justified in specific situations for particular sections of the Victorian land section. The Panel considered the various unique characteristics and sensitivities of the coastal plain section of the proposed SWOP/MerrimanMcGaurans route, and thus concluded that undergrounding of this section was in fact justified. Accordingly, the Panel recommended that an extra 5.2 kilometres of underground cable be installed (beyond that initially proposed by Basslink) to transverse this section of the proposed route. It should be noted that the acceptance of this recommendation will equate to a total of 6.5 kilometres of underground cable being installed across the coastal plain section of the project.

The Commission understands that the Commonwealth, Victorian and Tasmanian Governments gave their final approvals for the Basslink project in late 2002. Basslink now has the legal basis required to proceed with the construction. The Commission further understands that the construction will involve overhead transmission lines traversing designated National Park land sections on the Victorian side of the link.

Essential Services Commission of Victoria

The Commission has also taken into consideration the 2001 Victorian Electricity Distribution Price Review published by the ESC. As part of this review, both AGL and United Energy sought to include undergrounding projects in their capital plans. The ESC rejected these proposals on the grounds that the beneficiaries will be a limited number of consumers and consequently it would be unreasonable to allocate these costs across all customers (via distribution tariffs). The ESC has subsequently released an Issues Paper 'Review of Connection and Augmentation Guidelines, Volume 1: Undergrounding of Existing Assets' Sept 2002.

The Issues Paper indicates that the costs of undergrounding will be recovered from the party promoting the undergrounding of assets. However, the distribution business would contribute an amount equal to avoided distribution costs associated with undergrounding (ie, reduced maintenance costs, reduced vegetation management costs, reduced capital replacement costs associated with overhead assets). This ESC decision has significant implications regarding undergrounding, i.e. the majority of costs would be funded by customers (party seeking undergrounding) and as such these costs would not be included in the regulatory asset base of the distribution business.

Commission's conclusion on undergrounding

The Commission concludes that the case for undergrounding has not been made by MTC, having regard to the following:

- there are no legislative or policy requirements for undergrounding as acknowledged by MTC and its consultant, KBR. This point is also reinforced by the Basslink Joint Advisory Panel;
- the submissions of transmission planners from four states, TransGrid (NSW), Powerlink (Qld), ESIPC (SA) and Western Power (WA), agree that undergrounding is not required in this situation and that acceptance of undergrounding in remote areas could set costly precedents for future transmission projects. The SA Minister for Energy and the TNSP ElectraNet SA are also in agreement with those views. The Commission considers that the undergrounding of any particular project does not necessarily set precedents for future transmission augmentations in the NEM;
- submissions regarding environmental and planning considerations from Planning SA and the Victorian DSE arrive at different conclusions on the need for undergrounding. However, DSE was unable to state that undergrounding would be a required element, only a 'logical' solution in its view;
- MTC's "most likely" specification for Alternative 3 does not include undergrounding in the Sunset National Park in Victoria (an area where arguments for the potential need for undergrounding would have been expected);
- The Commission notes the success of Western Power in negotiating the siting of transmission lines within WA National Parks; and
- The Commission has also taken into consideration the 2001 Victorian Electricity Distribution Price Review published by the ESC. The ESC did not include in the regulatory asset base of various distribution businesses the cost of undergrounding, rejecting the proposals on the grounds that the beneficiaries will be a limited number of customers.

Therefore, the Commission considers that an allowance for the strategic undergrounding of Alternative 3 in such circumstances has not been justified by the proponent.

It is important to note that the Commission has consistently maintained the view that the regulatory test provides the most appropriate mechanism to determine the capital configuration upon which the regulated revenue should be based. In the case of Alternative 3, an underground line does not fit within the most efficient asset configuration.

Other issues

The Commission concurs with the views expressed by ElectraNet and Powerlink on the appropriate IDC to apply to the alternative projects. It has therefore made an allowance for IDC based on the 7.5 per cent of the total cost of the project.

It still considers that an allowance should be allowed for profit and overheads.

The Commission has also compared the cost of its adjusted Alternative 3 based on the adjustments outlined above, with the cost of the adjusted Alternative 3 proposed by the ESIPC, the NSW Minister for Energy and the SA Minister for Energy with the following inclusions. To ensure comparability, the items included in each of the project costings are:

- Development costs;
- 45 MVA SVC;
- PST and spare standard transformer;
- IDC;
- Contingency; and
- Profit and overheads.

The results of the Commission's comparison are outlined in the table below.

Table 4.15: Adjustment to the capital costs of alternative 3 ($millions)

Cost categories	**ESIPC**	**NSW Minister for Energy**	**SA Minister for Energy**	**Commission decision**
Total development costs	13.6	5.4	13.6	13.6
Total transmission line costs	29	24.8	28.6	28.6
Total switchyard costs	26.3	48.3	38.4	38.5
Total cost	**68.8**	**78.5**	**80.6**	**80.6**
10% profit and overhead	5.5	Included above	4.6	6.7
Interest during construction	6.6	4,500	6.6	6.1
P50 contingency costs	3	6.9	3	2.5
Total project costs (1 Oct)	**85.2**	**91.3**	**96.1**	**97.3**

The Commission consider that its cost data is robust considering the information provided by the NSW Minister for Energy, the SA Minister for Energy and the ESIPC for Alternative 3, with the differences primarily due to the different components included in the switchyard and substation works.

The main difference is with the costs presented by the ESIPC. The Commission obtained a copy of the Western Power report prepared for the ESIPC, but were unclear as to how ESIPC has derived the switchyard costs for Alternative 3 and therefore concurs with MTC that they are significantly understated.

Summary of costs

Based on its analysis, as outlined above, the Commission has determined the following cost for Murraylink and its alternative projects.

Table 4.16: Cost of Alternative Projects ($millions)

	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
development		$ 15.77	$13,.70	$13.70	$9.70
tx line works		$88.1	$22.86	$ 28.62	$37.92
switchyard		$57.32	$ 80.88	$38.47	$64.39
sub total		**$161.18**	**$116.91**	**$ 80.66**	**$111.98**
P&O		$14.54	$10.37	$6.71	$ 10.23
sub total		**$175.72**	**$127.280**	**$ 87.36**	**$122.21**
IDC		$12.09	$ 8.77	$6.05	$8.40
contingency		$3.05	$3.63	$2.48	$3.17
Total	**$ 176**	**$190.86**	**$ 139.68**	**$95.90**	**$133.78**
total cost (indexed 1 Oct 2003)	**$ 178.64**	**$193.72**	**$141.78**	**$97.33**	**$135.79**
augmentation costs	$15	$15	$15	$15	
life cycle opex	$45.56	$35.89	$33.89	$29.91	$29.91
total cost	**$ 239.20**	**$244.62**	**$190,.67**	**$142.24**	**$ 165.70**

The Commission notes that MTC provided the proposed capital cost of Murraylink and its alternatives in 1 May 2003. The Commission has inflated the captial cost of Murraylink and its alternatives to 1 October 2003 using the September quarter CPI. From this the Commission indexed the costs by 1.5 per cent for the period 1 May 2003 to 1 October 2003.

4.6.6 Conclusion

The Commission has considered the arguments advanced by MTC and the views of interested parties regarding the cost of Murraylink and its alternatives. The Commission has reached the following conclusions:

- a PST was included in the cost of Alternatives 1 and 3, but excluded from Alternative 4;
- a spare standard transformer in place of a PST for Alternatives 1 and 3;
- a smaller SVC in place of that proposed by MTC for voltage support;
- general allowance for spares set at 1 per cent of switchyard costs, and 1 per cent for spare SVCs;
- an allowance for contingency based on P50, 10 per cent profit and overhead, and interest during construction calculated at 7.5 per cent of total cost of projects; and
- the Commission concurs with Murraylink's proposed undergrounding for Alternative 1, however the Commission is of the view that undergrounding would not have been a requirement for Alternative 2 and 3.

Therefore, the Commission considers that the total cost (including the cost of the interconnector, augmentations for Murraylink and Alternatives 1, 2, and 3, and the life-cycle opex) for Murraylink, Alternative 1, Alternative 2, Alternative 3,and Alternative 4 are \$240 million, \$245 million, \$191 million, \$142 million, and \$166 million respectively.

Commission's Decision:

The Commission has considered the arguments advanced by MTC and the view of interested parties regarding the cost of Murraylink and its alternative projects, and considers that the total cost (cost of interconnector, augmentations, and life-cycle opex) for the options are as follows:

- **Murraylink - \$240 million;**
- **Alternative 1 - \$245 million;**
- **Alternative 2 - \$191 million;**
- **Alternative 3 - \$142 million; and**
- **Alternative 4 - \$166 million.**

4.7 Ranking of Alternative Projects

The regulatory test states that:

> a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) credible scenarios having regard to a number of alternative projects, timings and market development scenarios

Based on the power transfer capability of the alternative projects, the gross market benefits and the costs of the various alternative projects, the interconnector option which maximises the net present value of the net benefits to the market having regard to the alternative projects, timings and market development scenarios is Alternative 3.

A summary of the ranking of Murraylink and its alternative projects is presented in table 4.17. The net market benefits and ranking of Murraylink and its alternatives under credible market development scenarios and sensitivity analysis is presented in Appendix G.

Table 4.17 - Ranking of alternative projects ($ million)

Project name	GMB Minimum	GMB Maximum	Regulatory Cost	Ranking
Murraylink	$166	$347	$240	4
Alternative 1	$166	$347	$245	5
Alternative 2	$166	$347	$191	3
Alternative 3	$166	$347	$142	1
Alternative 4	$169	$350	$166	2

The Commission therefore deems that Alternative 3 satisfies the regulatory test. The Commission will therefore adopt the cost of Alternative 3, $97.33 million, for the purposes of setting MTC’s MAR.

Commission’s Decision

Alternative 3 is the option that maximises the net present value of the net benefits to the market having regard to alternative projects, timings and credible market development scenarios. Therefore, the Commission will adopt the cost of Alternative 3, $97.33 million, for the purpose of setting MTC’s MAR.

5 Operating and maintenance expenditure

5.1 Introduction

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 option or alternative that maximises the net present value of the market benefits under the Commission's regulatory test assessment.

The remainder of this chapter:

- sets out the requirements of the code (section 5.2);
- summarises the Commission's decision 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 proposals for the alternative projects, for the regulatory period (section 5.3);
  - a summary of the major findings of PB Associates' opex reviews (section 5.4);
  - summarises submissions by interested parties on the consultant report(section 5.5);
- a summary of the Commission's Preliminary View (section 5.6);
- summarises submissions by interested parties on the Preliminary View (section 5.7);
- sets out the Commission's considerations (section 5.8); and
- presents the Commission's conclusions in this regard (section 5.9).

5.2 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 MTC to meet its present and future service requirements. To this end, the Commission engaged PB Associates to review MTC's opex program as well as the estimated opex of the alternative projects. The results of PB Associates' reviews are summarised in section 5.4.

5.3 MTC's application

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:

Table 5.1 MTC's proposed opex allowance (2003 $million, excluding GST)

2003[1]	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

[1] This is for a six month period, I July 2003 to 31 December 2003

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; and
- a maintenance quote has also been received from a contractor.

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

5.3.1 Revised opex budget

On 4 August 2003, MTC submitted a revised opex budget on a confidential basis which contained the following changes to the budget submitted on 7 April 2003:

- following PB Associates' report on its proposed opex, MTC reviewed its plans for filter circuit breaker replacement and refurbishment and concluded it could reduce the number of units requiring replacement to a third of the total every five years and refurbish the others at that time;
- MTC has reduced its corporate costs so that they are now independent of its circuit breaker replacement and refurbishment plans; and

- the budget is now presented in terms of financial years as requested by the Commission.

The revised opex budget is summarised in the table below:

Table 5.2 MTC's revised opex budget (2003 $millions, excl GST)

2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13	2013[2]
3.73	4.37	4.46	4.46	5.45	4.44	4.43	4.43	4.42	5.41	0.9

[1] This is for a ten month period, 1 September 2003 to 30 June 2004
[2] This is for a two month period, 1 July 2013 to 30 August 2013

5.3.2 Proposed opex of Alternative Projects

As part of MTC's original application, BRW estimated the capital cost of the alternative projects. The cost estimates included development works, transmission line costs, switchyard costs, contractors' profit and overheads, and interest during construction.

BRW also estimated the opex costs for the alternative projects as follows:[52]

Table 5.3 Alternative Project Capital cost estimate ($million) Opex ($million pa) - including contingency

Alternative	Capital cost	Opex allowance
Alternative 1	245.9	3.6
Alternative 2	206.3	3.4
Alternative 3	201.6	3.5

5.4 Consultant's report

PB Associates was engaged by the Commission to undertake a review which analysed and commented on matters in relation to the contribution of opex to MTC's delivery of transmission services. PB Associates has also undertaken a review of the opex forecasts of the alternative projects, particularly Alternative 3, for the purposes of determining the revenue requirement of Murraylink.

5.4.1 Initial review of Murraylink and Alternative 3 opex: summary of findings

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:

[52] Only Alternatives 1, 2 and 3 have been included for examination as they provide the same or similar services to those provided by Murraylink.

- 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 its 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's 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 per cent of overall costs compared with other Australian TNSP rates of 30-45 per cent. While MTC does not have the same economies of scale as other TNSPs, 57 per cent is considered to be high; and
- overall opex costs are 2.1 per cent of the MTC asset based compared with 1-2.5 per cent 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 $2 million/km cost of underground cabling allowed in Alternative 3 appears to be high and PB Associates considers that an allowance in the range of $1 million to $1.5 million per km would be adequate;
- estimates for phase shifting transformers appear to be high by up to $5 million for each of the AC alternatives;
- BRW estimated $3.4 million opex costs for an HVDC option (Alternative 2) with 86 per cent of the line in overhead line instead of all underground cable for MTC. MTC's costs are significantly higher at $4.5 million; and
- the $3.5 million opex cost estimated for Alternative 3 is considered to be high.

5.4.2 Further review of Alternative 3 opex: summary of findings

MTC's interim submission on 30 June 2003 to the Commission's Preliminary View provided additional information from BRW regarding the forecast opex of Alternative 3. PB Associates was engaged by the Commission to undertake a review of this additional information and provided a report on 7 August 2003. PB Associates' findings are as follows:

	Cost Element	Standalone Alternative 3	Alternative 3 owned by incumbent TNSP
1	Management and operations	BRW estimate is significantly lower than the actual MTC costs. The estimate of $550k is considered appropriate and is unlikely to vary significantly with variable capital costs.	A local incumbent TNSP would be able to manage alternative 3 on a marginal basis, with costs expected to be 20-30% of those estimated by BRW.
2	Maintenance costs	Average transmission line maintenance costs per transmission km for other TNSPs are Transend ($1,300/km), Powerlink ($750/km) and Transpower ($900/km- for 220kV towers). Average line and cable annual costs would therefore be in the order of $250k/year assuming cable and line costs per km were comparable. Overall long-term annual maintenance cost for line, cable, transformer, SVC and secondary equipment is estimated to be approximately $400k. Costs during the early years of the asset life would be below this, but when economies of scale are considered, $400k is considered appropriate for the first 10 years of operation. BRW costs of $600k appear to be too high, especially when compared with actual MTC maintenance cost estimates and other TNSP information. The estimated $400k annual costs would decrease marginally with reducing capital costs.	Estimated annual costs of $400k would be lower if owned by a local incumbent TNSP due to economies of scale that could be applied. Risks would be lower as existing TNSP would also be managing comparable equipment.
3	Connection, commercial and regulatory	Costs are considered appropriate based on proposed connection fees for actual MTC link. Providing connection configuration with each TNSP remains the same, connection costs are unlikely to vary significantly with variable capital costs.	Marginal reduction in costs expected as commercial and regulatory requirements could be provided by existing TNSP capabilities.
4	Communications and energy	Communication costs are for line leasing between transmission locations and energy to provide external supply (not for energy consumption). Communication and energy requirements for alternative 3 should be less than the actual MTC link, which is reflected in the slight difference between the BRW estimate and the actual MTC link cost. Varying capital costs are likely to have minimal impact on communications and energy cost, subject to similar functionality.	Costs comparable to standalone alternative 3.
5	Insurance	Transend annual insurance costs are 0.18% of depreciated asset value ($1.0m) and SPI PowerNet 0.19% ($2.7m), equating to $380k for alternative 3. On a standalone basis, the insurance cost would be higher but should not be as high as that projected by BRW. They could be in the order of $500k. Varying capital costs may impact on the insurance estimates but not in a linear manner.	On incremental basis for an existing TNSP, costs could be expected to be in the order of $400k.
6	Accounting, audit, bank guarantee and	BRW costs for alternative 3 are comparable with actual MTC costs. Costs in the order of $300k are considered appropriate and varying capital cost would	These costs would be reduced to just taxes if managed by a local TNSP, in the order of

	taxes	have minimal impact on these.	$80k. Accounting, audit and bank guarantees requirements would have marginal imp-act on the existing TNSP costs.
7	Overhead, miscellaneous and contingency	BRW costs for alternative 3 are very similar to actual MTC costs. MTC previously advised that these costs were calculated on a % basis of other costs. As other costs are lower for BRW estimate than actual MTC costs, overheads etc should also be reduced. A level of $200k would be more appropriate which would not vary significantly as capital costs were reduced providing similar functionality was maintained.	The overhead, miscellaneous and contingency requirements should be minimal when operated by local TNSP

PB Associates considered that the efficient estimated costs of Alternative 3 should be closer to $3 million per annum rather than the $3.5 million determined by BRW, the largest differences being in the estimates for maintenance costs and insurance. In PB Associates' view, varying the capital costs of Alternative 3 would have minimal impact overall on these expenses.

5.5 Submissions on the consultant' s report

5.5.1 MTC's response to PB Associates' initial opex review

MTC's response to PB Associates' initial review of Murraylink's forecast opex stated:

- staffing levels are considered appropriate;
- MTC will replace a third of filter circuit breakers every five years and refurbish the others at that time;
- corporate costs will be independent of its circuit breaker plans; and
- PB Associates' finding regarding the level of fixed costs did not take into account the high proportion of connection charges which is beyond MTC's control.

5.5.2 MTC's response to PB Associates' further review of Alternative 3 opex

In a letter dated 18 August 2003, MTC and its consultant, BRW, responded to PB Associates' further review of the estimated opex for Alternative 3. It provided the following comments:

- terms of reference – advice on likely incremental opex costs incurred by an incumbent TNSP is not relevant to the consideration of MTC's application. To date, TNSPs have been allowed the efficient costs relevant to their own assets, not another TNSP's assets;
- PB Associates has agreed with BRW's estimates for most cost elements;
- BRW says that PB Associates' assessment of the variability of opex costs with capital cost is generally accurate (this was a matter for examination under the terms of reference). However, BRW advises that the actual assets and technology employed should be considered when estimating costs; and
- while Murraylink and Alternative 3 have similar cost elements such as connection charges, there are also significant differences such as maintenance costs which are based on the efficient operation of the Murraylink asset.

5.6 Commission's Preliminary View

In its Preliminary View, the Commission considered the estimated opex of Alternative 3 to be the appropriate cost to factor into the calculation of MTC's MAR, rather than the proposed opex of Murraylink itself. The Commission was of the view that this was consistent with its overall approach of referencing the costs of Alternative 3 (the project that maximised the net present value of the market benefits) to establish the regulatory asset value of Murraylink. The Commission considered that the opex allowance should be calculated at 1.5 per cent of Alternative 3's capital cost.

5.7 Submissions on the Commissions' Preliminary View

5.7.1 MTC's response to the Preliminary View

MTC states that if the Commission is to use a benchmark approach to setting opex, it is not appropriate to use a partial indicator based on a percentage of capital cost. Rather, if the Commission uses any type of benchmark regulation, it should take account of the physical and locational characteristics of the network assets being considered. In that regard, MTC submits that the Commission should perform a detailed analysis of expected costs of the alternative projects. MTC concurs with BRW's findings in its letter of 30 June 2003.

BRW states that, while it had indicated to Commission staff that the opex estimated for the alternatives are at a level of 1.46 to 1.85 per cent of estimated capital costs, this statement should not have been construed to mean that BRW had estimated the opex using those percentages. In its view, it is not a valid approach as some costs such as connection charges are fixed and insensitive to changes in capital cost. BRW has also provided a breakdown of its estimated costs for Alternative 3 in its letter of 30 June.

The ACG, on behalf of MTC, states that the Commission's approach to benchmarking would not predict an efficient level of opex as it uses only one explanatory variable, and ignores the fixed portion of operating costs such as connection charges. Therefore, the Commission should take into account Murraylink's actual opex to derive a forecast of future expenditure. This could at least be used to estimate the difference in the opex of the alternative projects compared to Murraylink itself.

5.7.2 Submissions from other interested parties

ElectraNet agrees with MTC that it is inappropriate to set opex based on a simple percentage of capital value approach. It observed that staffing levels appear high and TNSPs would normally expect a 45 year life span for circuit breakers, not 5 or 10 years as assumed by MTC. ElectraNet would base the opex allowance on a detailed breakdown of the estimated costs.

The EUCV comments that the proposed opex is too high. It argues that there has been no benchmarking of opex and more rigour is needed than using a percentage of asset value approach. It adds that as a new asset, Murraylink's opex should be significantly lower than the average opex/km measure allowed for TNSPs such as ElectraNet.

The ECCSA comments that the opex allowance needs to be reduced. It argues that no benchmarking was performed to assess the percentage of asset value approach used to set Murraylink's opex. The ECCSA believes that the newness of the plant must be taken into account.

The SA Minister for Energy disagrees with tying opex to asset value and considers that rigorous benchmarking should be carried out to determine the opex allowance.

TransGrid, through its consultant, NERA, states that an opex allowance below actual operating costs is unlikely to be robust. It prefers the approach proposed by Murraylink where the opex is set based on its actual opex projection. This amount would then be subtracted from the total regulated cost of Alternative 3 to derive Murraylink's regulatory asset value.

ESIPC states that it supports the submissions of other parties at the public forum held in Adelaide on 8 July 2003 regarding the quantum of opex allowed in the Commission's Preliminary View.

5.7.3 MTC's response to submissions by interested parties

MTC submits that some stakeholders, without providing supporting evidence, have argued that MTC's forecast opex costs appear too high. MTC reiterates that its forecast opex costs are efficient and reflect the cost of service that Murraylink provides.

5.8 Commission's considerations

In reaching its views regarding the appropriate amount opex to be allowed, the Commission has taken into account the reviews undertaken by PB Associates and the comments of interested parties.

A number of submissions raised the issue of the appropriateness of adopting a benchmarking approach to setting opex based on a percentage of asset value. Additional information has been provided by BRW since the release of the Commission's Preliminary View which has allowed the Commission to base its calculations on the efficient estimated costs of Alternative 3.

Some submissions also pointed out that the determination of opex should be made by reference to Murraylink's actual expenses. Reasons advanced for this approach included consistency with an ODRC valuation of Murraylink (ACG), or the robustness of the decision against the need to be reopened at some future date (NERA). These matters are dealt with below.

The Commission stated in its Network Pricing and Market Network Service Providers code changes authorisation that it would apply an ODRC valuation for conversion applications, and that the process must deliver outcomes consistent with the intent of the regulatory test. However, as explained in its Preliminary View, the Commission is not convinced that defining the gross market benefits as the economic value of Murraylink will provide that consistency. Therefore, the Commission determined the regulatory asset value of Murraylink based on the option that maximises the net present value of the market benefits under the regulatory test assessment, which it considers approximates an ODRC valuation. This has implications for the setting of the opex allowance.

Methodology for setting opex

BRW has provided a breakdown of the estimated costs of Alternative 3 in MTC's interim submission of 30 June 2003 on the Commission's Preliminary View. This additional information has allowed the Commission to more fully consider the proposed opex of Alternative 3, and has been reviewed by PB Associates to determine an efficient level of expenditure for that project.

This is important, as the approach the Commission has adopted to setting the MAR of Murraylink is based on Alternative 3. That is, the MAR has been set by reference to the regulatory asset value and efficient opex of Alternative 3, not Murraylink itself.

This approach recognises the degree of optimisation of Alternative 3 (as originally specified by BRW) that the Commission considers appropriate. Ultimately, the Commission is seeking to establish the efficient expenses of operating the assets of a reconfigured Alternative 3, that being the project that maximises the net present value of the market benefits. Essentially, the Commission considers that efficient opex should relate to maintaining and operating the optimised network.

BRW in its estimation of the costs of Alternative 3 stated that significant opex components such as connection charges are not sensitive to the level of capital costs of the project. PB Associates' review has confirmed that these expenses vary only minimally with the capital costs of the project. Therefore, optimisation of Alternative 3 will not have a significant impact on the opex allowance. Finally, the Commission considers it appropriate to treat the estimated costs on a stand alone basis, rather than pertaining to a link owned and operated by an existing TNSP.

5.9 Conclusion

The Commission has based its opex determination on the estimated costs of Alternative 3, the project that maximises the net present value of the market benefits under the regulatory test assessment. Taking into account PB Associates' opex reviews, the views of interested parties and the Commission's analysis of efficient costs, the Commission grants opex totalling $32.71 million (nominal) over the regulatory period, as follows:

Table 5.3 Murraylink opex: 1 October 2003 to 30 June 2013 (nominal $million, excluding GST)

2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66

[1] This is for a nine month period, 1 October 2003 to 30 June 2004.

Commission's Decision:

The Commission will grant opex based on a determination of the efficient costs of Alternative 3, the lowest cost alternative, totalling $32.71 million (nominal) over the regulatory period. This represents an increase of $13.34 million (nominal) over the Preliminary View due to the different basis employed to determine the costs.

6 Pass-through events

6.1 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 remainder of this chapter:

- sets out the Commission's pass-through rules (section 6.2);
- sets out the general operation of the pass-through mechanism (section 6.3);
- summarises the Commission's decision concerning the pass-through events to be allowed as well as the information considered by the Commission in arriving at that conclusion. This includes:
    - MTC's pass-through proposal (section 6.4);
    - summarises the Commission's Preliminary View (section 6.5);
    - summarises submissions by interested parties in response to the Preliminary View (section 6.6)
- sets out the Commission's considerations (section 6.7); and
- presents the Commission's conclusions in this regard (section 6.8).

6.2 Pass-through rules

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;

- 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; and
- 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 affect the commercial viability of the business.

6.3 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; and
- 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.

6.4 MTC's application

MTC proposes that the pass-through mechanism would operate for five categories of events:

- a Change in Taxes Event;
- a Service Standards Event;
- an Essential Contract Event (the earlier Non-contestable Capital Works Event was deleted in response to the Commission's Preliminary View);
- 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 and the Essential Contract Event, the Commission generally approves such arrangements, with the amendments outlined below.

MTC's proposed pass-through rules were originally detailed in its letter dated 4 April 2003 to the Commission.

6.5 Commission's Preliminary View

In its Preliminary View, the Commission considered MTC's application and subsequent information on its proposed pass-through events. With the exception of the Non-contestable Capital Works Event, the Commission accepted MTC's proposal. In its Preliminary View, the Commission allowed pass-through for the following events:

- a Change in Tax Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

6.6 Submission on the Commissions' Preliminary View

6.6.1 MTC's response to the Preliminary View

MTC states that it accepts as reasonable the amendments to the pass-through rules made by the Commission.

In a letter dated 19 August 2003, MTC provided amended pass-through rules which incorporated changes required by the Commission in its Preliminary View. MTC also proposed a new event, an Essential Contract Event, for consideration. Broadly, this event was introduced to cover changes in MTC's connection or revenue recovery contracts that were beyond MTC's reasonable control.

6.6.2 Submissions by other interested parties

Powerlink agrees in principle with pass-throughs where the risk is too difficult to manage or quantify reasonably accurately in advance.

TransGrid comments that cost pass-throughs must apply equally to all TNSPs for regulatory consistency.

6.7 Commission's considerations

The Commission has assessed Murraylink's proposed pass-through arrangements under the tests for pass-through events detailed above, which focus on events that are essentially uncontrollable, unpredictable, material in financial impact and which are particular to the TNSP itself.

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, charge, 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.

The Commission notes that MTC accepted the above changes in its letter of 19 August 2003 dealing with pass-through rules revision.

Exclusion of certain events as pass-through events

Non-contestable Capital Works Event

> MTC had 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.

The Commission notes that MTC withdrew this proposed event in its revised pass-through rules submitted on 19 August 2003.

Essential Contract Event

MTC included this event in its revised pass-through rules submitted to the Commission on 19 August 2003. MTC has defined an Essential Contract Event to mean:

(a) a decision made by ElectraNet SA, VENCorp, SPI PowerNet, the Commission or any other Authority; or

(b) any introduction of or amendment to an Applicable Law after the date of the Determination,

that has the effect of changing MTC's connection or revenue recovery contracts with ElectraNet SA, VENCorp, SPI PowerNet, or their successors, in a manner that is beyond MTC's reasonable control.

As noted by MTC, this event essentially replicates paragraph (iii) of MTC's Service Standards Event as originally proposed, and which was subsequently disallowed by the Commission in its Preliminary View.

The Commission has further considered this event now that it is defined as a discrete pass-through event.

MTC has applied for an allowance in its opex claim for the expected costs to be incurred under connection and revenue recovery contracts with other parties. The proposed event is intended to deal with changes to those contracts that are beyond MTC's reasonable control.

In the Commission's view, there is a question regarding the degree of uncontrollability potentially present in these contracts. The Commission expects that MTC would be in a reasonable position to negotiate mutually agreeable terms under connection or revenue recovery contracts it enters into with ElectraNet SA, VENCorp, or SPI PowerNet. The Commission notes that the code imposes certain obligations on co-ordinating network service providers which the Commission considers would be a factor in any contractual negotiations between MTC and those businesses. Therefore, the Commission is not convinced that there is a reasonable likelihood that counterparties to the contracts would change those contracts in a unilateral fashion.

Further, the proposed event would cover, for example, a code change that had the effect of changing MTC's contracts. In these situations, it is arguable that the pass-through event, if allowed, would nullify the intended effect of the code change, a result that would seem at odds with the reason for the code change in the first place. The Commission has considered the bilateral nature of these contracts and is mindful of the interests of the other parties (whom it also regulates) in coming to this conclusion. Additionally, other TNSPs do not presently have this kind of contractual protection built into their pass-through arrangements.

Consequently, the Commission does not consider that an Essential Contract Event should be included as a pass-through event.

6.8 Conclusion

The Commission has taken into consideration MTC's proposals for the inclusion of certain pass-through arrangements into its revenue cap, and submissions from interested parties. The Commission concludes that the Change in Taxes Event, Service Standards Event, Terrorism Event and Insurance Event meet the guidelines expressed in section 6.2, with the stated amendments. However, the Commission does not accept the Non-contestable Capital Works Event or the Essential Contract Event for the reasons detailed above.

Commission's Decision:

The Commission will allow pass-through for the following events, as amended:

- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

These are the same events the Commission allowed in its Preliminary View.

7 The cost of capital

7.1 Introduction

Clause 6.2.2(b)(2) of the code requires that the Commission seeks 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)(4) of the code in which it is stated that the Commission must have regard to the weighted average cost of capital (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 return on capital generally accounts for about two-thirds of the allowable revenue (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 costs and the ability of firms to compete domestically and overseas, and will have a significant impact on downstream investment and allocative efficiency.

The remainder of this chapter:

- sets out the capital asset pricing model (CAPM) adopted by the Commission; and

- summarises the Commissions decision concerning the key parameters relevant to the CAPM/WACC to be allowed as well as the information considered by the Commission in arriving at that conclusion. This includes:

  - MTC’s proposal for each of the WACC/CAPM parameters;
  - summarises the Commission’s Preliminary View on each of the CAPM/WACC parameters;
  - summaries submissions by interested parties in response to the Preliminary View; and
  - presents the Commission’s conclusions for each of the key parameters relevant to the CAPM/WACC.

7.2 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:

> “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 varies models 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, the code notes that the CAPM remains the most widely accepted tool applied in practice to estimate the cost of equity.

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;

$(R_m - R_f)$ = 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.

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.

7.3 WACC parameters

A number of interested parties raised the issue that the Commission should apply consistent parameters to MTC as in its previous revenue cap decisions. These are outlined below.

7.3.1 Submissions on the Commission's Preliminary View

MTC's response to the Preliminary View

MTC notes that it continues to support the view that the parameters put forward in Professor Officer's advice[53] are appropriate.[54] It also notes that the Commission proposed return on capital for MTC is consistent with the Commission's previous decisions and MTC would expect the Commission's final determination to also be consistent with these numbers.

Submissions by other interested parties

The SA Minister for Energy submits that the Commission should maintain a consistent approach with its revenue cap determinations for TNSPs. TransGrid notes that the approach adopted by the Commission to the calculation of WACC must also apply to other TNSPs. ESIPC states that it would support, in the absence to the contrary, consistency of the WACC numbers with recent TNSP revenue resets.

The SA Minister for Energy notes that it can see no reason why the WACC included in the Preliminary View should be higher than that awarded by the Commission to ElectraNet. It further indicates that as Murraylink is only operating one asset which, once regulated, would operate with little or no market risk, the SA Minister for Energy considers that the WACC awarded to Murraylink should be significantly less than that granted to ElectraNet for example.

7.3.2 Commission's consideration

The Commission notes the comments with respect to consistency between the WACC granted to MTC and the WACC provided to TNSPs in the Commission's revenue cap determinations for the respective TNSPs. The Commission will consider these comments in its assessment of each of the WACC parameters, along with other specific comments made by interested parties on a particular WACC parameter, which are summarised in their respective sections below.

[53] MTC commissioned a report by Professor Bob Officer to examine MTC's capital financing and taxation issues.
[54] These are outlined in the Commission's assessment of each of the WACC parameters below.

7.4 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 Commission's 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 *Draft Regulatory Principles* 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."

7.4.1 MTC's application

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

Professor 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 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, Professor 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.

Professor 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 due to some short-term uncertainty. Professor 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 lessens the information content in the last rate about expected future rates.

7.4.2 Commission's Preliminary View

In its Preliminary View, the Commission proposed maintaining the current approach to linking the bond term to the length of the regulatory period using a 10-day moving average for the interest rate sample, which was consistent with the Commission's recent SPI PowerNet and ElectraNet revenue cap decisions. At the time of the Commission's Preliminary View, the 10-year, 10-day moving average for bond rates provided a rate of 5.19 per cent.

7.4.3 Submissions on the Commissions' Preliminary View

Submissions by interested parties

ElectraNet supports the use of a 10-year term to determine the risk free rate WACC parameter. However, it notes that it has previously argued that these parameters should be linked to the long life of the assets involved and not the term of the regulatory period.

7.4.4 Commission's considerations

Term of the risk free rate

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 including ElectraNet argue that the use of a longer-term rate represents an appropriate measure given the long lives and investment horizons of most assets.

The Commission has previously noted 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 accepts that the approach it has adopted is not consistent with the approach of other Australian regulators. However, in both the Central West pipeline and Northern Territory gas pipeline decisions, the Commission adopted a 10-year regulatory control period, and the 10-year approach to determine the appropriate risk free rate and cost of debt was used. Furthermore, a bond yield term the same as the regulatory period is consistent with the approach outlined in the *Draft Regulatory Principles* and consistent with the approach adopted in the Commission's Queensland, Victoria and South Australian Revenue Cap Decisions.

The Commission sought advice from Dr Martin Lally on this and several other risk free related issues.[55] Dr Lally advised that the Commission's approach in establishing the risk-free rate was theoretically correct and appropriate in practice, given the nature of the financial framework being used. Dr Lally assessed the arguments proposed for not using the 5 year bond rate determining that these arguments are largely unfounded. However, the Commission notes criticism by interested parties on the assumptions adopted in the Dr Lally report, and thus engaged Professor Kevin Davis

[55] Lally, Martin, *Determining the risk free rate for regulated companies*, a paper for the ACCC, July 2002.

to incorporate these arguments into a discussion on the appropriate bond rate to use for the risk free rate.[56]

Professor Davis comments that because long-term interest rates will, on average, exceed short term interest rates for reasons other than expectations of future increases in interest rates, the use of the longer term interest rate as a proxy for the risk free rate will lead to higher regulatory cash flows than if the short-term were used. Professor Davis demonstrates that the use of an interest rate with maturity equal to the regulatory period in deriving the required rate of return for the regulated asset generates expected cash flows, which are fairly priced in net present terms. Furthermore, using a maturity, which exceeds the regulatory period, provides excess returns for the regulated asset if there is a positive term premium in the yield curve, unrelated to interest rate expectations.

The Commission therefore believes that using the bond rate with the term to maturity corresponding to the regulatory control period is the appropriate approach. As such, given the Commission has adopted a 10-year regulatory control period for MTC, the Commission will use a 10-year bond yield term.

Sampling period for the risk free rate

In relation to the measure of the risk free rate, the Commission understands that it is theoretically correct to measure rates on the day immediately prior to the start of the regulatory period, as the rates do not include superseded news. However, in practice regulators including the Commission have often employed a moving average of the bond yields to smooth out any possible market aberrations. The Commission recognises the inherent limitations of using an on the day rate and a historical average approach in the calculation of the risk free rate for the purposes of CAPM. By using an on the day rate, rates may reflect short term fluctuations which may differ to long term trends, due to market volatility. Such volatility can be minimised by averaging rates over a short term before the start of the regulatory period.

The Commission adopted the 40 trading day average in TransGrid, and Powerlink revenue cap decisions. However, in the Commission most recent SPI PowerNet and ElectraNet decisions, the Commission adopted a 10-day moving average of bond rates as it was of the view that such an approach had practical advantages.

The Commission remains of the view that it is appropriate to use a short-term average of the risk-free rate, and proposes to adopt a 10-day sampling period for this decision. This offers a degree of protection from transient volatility while ensuring that the selected rate closely reflects the most recent market activity.

At the time of this Decision, the nominal 10-year, 10- day moving average for Commonwealth bond rates results in a risk free rate of 5.46 per cent. The Commission notes that while the figure differs to that adopted in its Preliminary View, its approach to deriving the risk free rate is consistent with its approach in the

[56] Davis, Kevin, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for ACCC, 11 August 2003.

Preliminary View. The variation in the risk free rate figure reflects the prevailing market conditions/data at the time of this decision.

Commission's Decision

The Commission has adopted a 10-year regulatory control period for MTC, and therefore will use a 10-year bond yield term. Furthermore, the Commission proposes to use a 10-day sampling period for this decision. This approach is consistent with the Commission's Preliminary View.

At the time of this Decision, the nominal 10-year, 10-day moving average for Commonwealth bond rates results in a risk free rate of 5.46 per cent.

7.5 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 its internal modelling.

Statement 6.11 of the *Draft Regulatory Principles* 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."

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. This approach has been adopted for all of the Commission's revenue cap decisions.

7.5.1 MTC's application

MTC has proposed an expected inflation rate of 2.2 per cent. MTC uses the difference between a 10-year bond rate and a 10-year indexed bond.

7.5.2 Commission's Preliminary View

Using the extrapolated and real bond rates yielded a forecast inflation rate of 2.11 per cent for the Commission's Preliminary View.

7.5.3 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.

The Commission method for deriving the inflation rate from the nominal and indexed bond rates in this Decision is consistent with the *Draft Regulatory Principles* and other Commission and jurisdictional regulatory decisions.

For this Decision, the Commission forecasts inflation of 2.07 per cent. The Commission notes that the forecast inflation rate in this decision differs to the figure adopted in the Preliminary View. The variation in the forecast inflation rate reflects the prevailing market conditions/data at the time of the Preliminary View and this Decision. The Commission also notes that its approach to deriving the forecast inflation rate for this Decision is consistent with its approach in the Preliminary View.

Commission's Decision

The Commission method for deriving the inflation rate from the nominal and indexed bond rates in this Decision is consistent with the DRP, the Commission's Preliminary View, and other Commission and jurisdictional regulatory decisions.

For this Decision, the Commission forecasts inflation of 2.07 per cent.

7.6 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."

7.6.1 MTC's application

MTC proposes a debt margin of 150 basis points (bp) over the risk free rate (based on an 'A' rated debt), which corresponds to a debt margin of 1.5 per cent. This is based on a rating at the midpoint of the A to BBB+ range. MTC contends that this rating is supported by the fact that it is a single asset company, with actual costs higher than the regulatory asset value that it submitted, and the resulting impact on financial ratios.

Professor Officer states that the current spread of the bond ratings for 'A' rated debt is 142 bp and 160 bp for 'BBB+' debt, which ElectraNet SA indicated was its rating. Professor Officer also states that the rating for a company such as Murraylink with 60 per cent 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 per cent implies a beta of around 0.25 per cent, although Officer has rounded this figure to 0.2 per cent. Professor Officer states that although a debt beta of 0.2 implies a debt margin of 120 bp, 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 bp where ElectraNet argued for 172 bp. Professor 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.

7.6.2 Commission's Preliminary View

In the Preliminary View, the Commission assumed a benchmark credit rating of A for MTC, which is the average credit rating for the electricity industry. Based on relative market information, the Commission found that a firm with an A credit rating would have a debt margin of around 145 bp, based on a ten-year term.

The 145 point margin was added to yield on a 10-year nominal risk free rate of 5.19 per cent which suggested a nominal cost of debt figure of 6.64 per cent for use in the WACC estimate.

7.6.3 Submissions on the Commission's Preliminary View

Submissions by interested parties

Powerlink notes that using a 10-year framework should give the same WACC as using a 5-year framework as the debt margin and the market risk premium should be based on the appropriate framework. It notes that the 1.45 debt margin provided to MTC is higher than that received by Powerlink and that its analysis indicates that the difference in the 5 and 10 year bond rates was 0.32 per cent at the time of the calculations for the Preliminary View and suggests that the correct debt margin that the Commission would apply for a TNSP using a 5 year framework is 1.77 per cent.

ElectraNet submits that the use of a ten-year term to determine the debt margin parameter should be linked to the long life of the assets involved and not the term of the regulatory period.

EUCV and ECCSA note that the Commission have allowed a debt margin of 1.45 and recommend that the debt margin be the same as those awarded to ElectraNet and SPI PowerNet at 1.2.

MTC's response to submissions by interested parties

MTC notes that the Commission has applied the same principles to the determination of MTC's debt margin as it has applied for previous decisions. MTC would expect that the Commission's final decision to also be consistent with its Preliminary View.

7.6.4 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 *Draft Regulatory Principles*.

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.

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 the determination of other WACC parameters.

The Commission considers relevant Australian electricity transmission and distribution companies should be used as the basis of a benchmark. Table 7.1 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 7.1 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, *Australian Report Card and Utilities*, April 2003.

On the basis of this current data, the average credit rating of these entities approximates to an average credit rating of A. Standard and Poor's states that the regulated entities are generally stable network or transmission businesses.[57]

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 simply using stand alone and private entities would provide too small a sample to obtain an average credit rating for the electricity industry. The Commission also notes that 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, Standard and Poor's consider a number of key sources. Specifically, they relate to regulatory risk, counter party risk and overall volume of demand for gas.

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 markets for projects involving construction in Australia.[58]

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. The Commission therefore considers that it is reasonable to use capital market data as the benchmark.

The Commission notes that the debt margin should reflect the prevailing market rates for debt issues at the benchmark maturity and credit rating for the regulated entities. This therefore explains the differences in the debt margin applied by the Commission in its previous decisions.

As the Commission has adopted a 10-year regulatory control period, it considers it appropriate to determine the debt margin based on a 10-year term. Therefore the current 10-day moving average benchmark spread over the government bond yields, for A rated corporate bonds with a maturity of 10-years, is 086 bp.[59] Combined with a nominal risk free rate of 5.46 per cent, it suggests a nominal cost of debt figure of 6.32 per cent for the use in the WACC estimates.

The Commission notes that the debt margin in this decision differs to the figure adopted in the Preliminary View. The variation in the debt margin reflects the prevailing market conditions/data at the time of the Preliminary View and this decision. The Commission also notes that its approach to deriving the debt margin for this decision is consistent with its approach in the Preliminary View.

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[57] Standard and Poor's, *Australian and New Zealand Electric Utilities Ripe for Rationalisation*, May 2002.

[58] Macquarie Bank, *Issues for debt and equity providers in assessing greenfields gas pipelines,* Report for the ACCC, May 2002. p7.

[59] CBASpectrum website: www.cbaspectrum.com

Commission's Decision

As the Commission has adopted a 10-year regulatory control period, it considers it appropriate to determine the debt margin based on a 10-year term. Therefore the current 10-day moving average benchmark spread over the government bond yields, for A rated corporate bonds with a maturity of 10-years, is 086 bp. Combined with a nominal risk free rate of 5.46 per cent, the Commission proposes a nominal cost of debt figure of 6.32 per cent for the use in the WACC estimates.

7.7 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 *Draft Regulatory Principles* 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, conventional 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.

7.7.1 MTC's application

MTC proposes a MRP of 6.0 per cent, which is consistent with the Commission's previous regulatory decisions. Professor 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. Professor Officer provides graphs to demonstrate the justification for a MRP of 6.0 per cent. The 10-year period the average and the exponential moving average show a trend towards a 6.0 per cent MRP.

Professor 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. Professor Officer also claims that Australian results are consistent with countries such as the US, UK and Canada whose capital markets are very similar to Australia. Professor Officer notes that the evidence highlighted above points to an estimate of 6.0 per cent for MRP.

7.7.2 Commission’s Preliminary View

Consistent with its previous revenue cap decisions, the Commission adopted a MRP of 6 per cent in the Preliminary View.

7.7.3 Submissions on the Commission’s Preliminary View

Submissions by interested parties

Powerlink notes that according to its assessment a value of 6.3 per cent for the risk premium was used to arrive at the 8.45 per cent vanilla WACC.

The ECCSA and EUCV believe that the MRP granted by the Commission is too high, and references studies by Pareto (2002), Mercer Consulting (2002), and EUCV (2002), which indicate that the MRP is approximately between 3-4 per cent. The ECCSA and EUCV also indicated that it had received funding to examine the market risk premium and the equity beta. It noted that this work is analysing the past 5 year returns of the 300 largest (by sales) Australian public and private companies and that data has been provided by IBISWorld. It notes that the initial findings are that the weighted average gearing (debt to total company assets) of all these companies is 77 per cent and after a ‘relevering of 60 per cent gearing’, the MRP is 4 per cent.

EUCV and ECCSA submit that the data and studies listed above are relatively recent and regulators should recognise that continuing with inflated elements for the CAPM formulae only continues to provide an incentive to regulated businesses to maximise its asset values and planned capex. Furthermore, the EUCV and ECCSA note that on the balance there is a increasing body of evidence that the MRP suggested by regulated businesses and used in the CAPM formulae by regulators are too high, and recommends that the Commission reduce the MRP to 4 per cent.

MTC’s response to submissions by interested parties

MTC submits that a MRP lower than 6 per cent is inappropriate. It further notes that while it continues to support the parameters put forward in its application are more appropriate, MTC recognises that the parameters proposed in the Commission’s Preliminary View are consistent with the Commission’s previous decisions.

7.7.4 Commission’s considerations

The Commission notes that research indicates that the MRP has fallen over recent years. However, the Commission is wary that this may reflect short term market trends. The Commission’s assessment of the MRP suggests that it lies between 5.0 per cent and 7 per cent. For this decision the Commission chooses the mid-point of this range, which is a MRP of 6 per cent. This is consistent with a comprehensive study by Dr Lally for the Commission, which recommended a MRP of 6 per cent as reasonable.[60]

[60] Lally, Martin, *The Cost of Capital under Dividend Imputation*, Report for the ACCC, June 2002.

There is often comment made that historical estimates of the MRP have been calculated as some historical average of the actual market return over a long term risk free rate. Typically the risk free rate used is a 10-year government bond rate. Therefore, the assertion is made that if these estimates of the MRP are to be used in CAPM, consistency requires that a long term bond be used as the risk free rate. However, Davis outlines a number of arguments against those advocating such a position. [61] Davis states:

> "There are a number of arguments which can be advanced against the strictures advocated by such a position.
>
> (a) The MRP should be forward looking. Historical data provides some benchmark, but should not be accepted uncritically.
> (b) The method of estimation of historical MRP figures is subject to much debate. Arithmetic or geometric averages may be used (with significant effects on the result). An approach sometimes used is to compare contemporaneous 10 year bond yields to maturity with annual holding period returns on the market portfolio. This has no correspondence with the concept of the MRP in the CAPM which involves comparison of a risk free return and a market return for the same holding period.
> (c) The MRP can be expected to vary over time.
> (d) The historical MRP estimates are derived primarily from a period without dividend imputation and reflect equity returns without franking credits. The MRP estimate required now involves equity returns inclusive of the value of franking credits. While a plausible argument can be advanced those estimates will be equal in magnitude, there is no guarantee that this is the case."

The Commission notes that UK regulators have used an historical MRP of around 3.5 per cent. However, the rationale for the difference is that there are still perceptions of segmented stock markets and investors require a higher risk premium to invest in the Australian market. It should be noted that the Commission assumes a domestic CAPM version in estimating the required cost of equity. Further, the UK adopts a 'real' CAPM so that direct comparisons with the Australian experience are not straight forward.

The Commission also notes a Jardine Capital Partners survey of professional market participants' MRP expectations found that on average these participants thought the historical MRP for Australia was 5.87 per cent. The survey also found the expectation for the future MRP is approximately 1.0 per cent below this figure. However, the Commission believes that these expectations reflect a significant amount of uncertainty and is not persuasive enough to revise the Commission's past assumptions. If the Commission is satisfied that the MRP is trending downwards in the longer term, it will adopt a lower MRP.

Commission's Decision
For this decision, the Commission has applied a MRP of 6 per cent. This is consistent with the Commission's previous revenue cap decisions and its Preliminary View.

[61] Davis, Kevin, *Report on Risk Free Interest Rate and Equity and Debt Beta Determination in the WACC*, Report for the ACCC, 11 August 2003.

7.8 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) [62] 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.

7.8.1 MTC's application

MTC has proposed the value of imputation credits to be 45 per cent. 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, Professor 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. Professor 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 Professor Officer says can be expected to lead to a greater variability in the estimate and a slightly lower estimate, other things being equal. Professor 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, Professor 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. Professor Officer concludes that 45 cents is a compromise estimate.

7.8.2 Commission's Preliminary View

In the Preliminary View, the Commission has continued to value franking credits at 50 per cent (gamma of 0.5), consistent with its previous decisions and those of other Australian regulators.

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

7.8.3 Submissions on the Commission's Preliminary View

MTC's response to the Preliminary View

MTC notes that it continues to support the view that the parameters put forward in Professor Officer's advice, attached to MTC original application, are appropriate. Furthermore, it recognises that the Commission's proposed return on capital and value of imputation credits for MTC is consistent with the Commission's previous decisions and MTC would expect the Commission's final decision determination to also be consistent with these numbers.

7.8.4 Commission's considerations

Gamma incorporates not only what proportion of earnings are paid out as dividends with imputation credits, but also the proportion of the imputation credits that are able to be used. The Commission notes that arguments can be made in favour of adopting a higher gamma, particularly when considering Dr Lally's arguments[63] and the impact of recent changes to taxation law.

However, the Commission also recognises that further research is required and no 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 to alter its position on gamma at this stage. Hence, a gamma of 0.5 will be used in this Decision.

Commission's Decision
For this Decision, the Commission has adopted a gamma of 0.5.

7.9 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 has proposed a gearing ratio of 60 per cent debt to equity for its business. MTC has also reiterated its support for this value in its response to the Commission's Preliminary View.

In the Commission's previous revenue caps, it has adopted a gearing ratio of 60 per cent based on industry wide benchmarking.

[63] Lally, *The Cost of Capital under Dividend Imputation*, Report for the ACCC, June 2002

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 7.2 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 no compelling reason to vary from this assumption.

Table 7.2 Gearing levels adopted in regulatory decisions

Entity	Industry	Debt/Debt+Equity (per cent)
QCA(2001)	Electricity distribution	60
ESC (2000)	Electricity distribution	60
ACCC (2002)	Electricity transmission	60
IPART (1999)	Electricity distribution	60
OFGEM (1999)	Electricity distribution (UK)	50
ACCC/ESC (1998)	Gas transmission	60
IPART (1999)	Gas distribution	60
OTTER (1999)	Electricity distribution	50-70

In the *Draft Regulatory Principles*, the Commission noted that it would not be using the actual gearing of a TNSP, instead it would use an appropriate benchmark. A survey conducted by Standard and Poor's suggests that the upper and lower band of the gearing ratio for a transmission and distribution business should be 65 per cent and 55 per cent.[64]

Therefore the Commission will adopt a gearing ratio of 60 per cent, which is consistent with recent regulatory decisions.

[64] Standard and Poor's, *Rating Methodology for Global Power Companies*, 1999.

Commission's Decision

For this decision, the Commission will adopt a gearing ratio of 60 per cent. This is consistent with its Preliminary View and recent regulatory decisions.

7.10 Betas and risk

The equity beta is a measure of the expected volatility of a particular stock relative to the market as a whole. It measures the systematic risk of the stock, that is the risk that cannot be eliminated in a balanced and diversified portfolio. An equity beta of less than one indicates that the stock has a low systematic risk relative to the market, and 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).

For publicly listed companies, equity betas can be calculated using their dividend stream plus the change in the value of the stock. However, when the firm is not listed, equity betas cannot be calculated directly from economic returns. In such cases, conventional practice has been to benchmark the firm's equity beta relative to other companies or sectoral averages. In the context of regulated electricity networks even this approach is problematic, as there are limited Australian reference stock for such businesses.

When an equity beta from a comparable firm is calculated for a particular company, it only applies for the particular capital structure of the firm. A change in the gearing will change the level of financial risk borne by the equity holders and therefore the equity beta. A common approach is to enable betas to be compared across companies with different capital structures to derive the beta that would apply if the firm were financed 100 per cent equity (by de-levering). This is known as the asset or 'unlevered beta' and can then be used to calculate the equivalent equity beta for a particular level of gearing. While there are a number of levering formulae, the Commission consistently applies the formula developed by Monkhouse:[65]

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

The role of the debt beta is in the de/re-levered process of equity betas. The debt beta captures the systematic risk of a debt analogue of equity beta. When converting between asset betas and equity betas, it involves converting measures of systematic risk for the effect of debt in the capital structure. Therefore, the function of the debt beta is to show how there is a sharing of a firm's systematic risk between the systematic risk of equity and debt.

7.10.1 MTC's application

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

[65] See ACCC, *Draft Regulatory Principles*, pp. 79-81.

With respect to the debt beta, Professor Officer notes that adopting the debt margin implied by the 150 bp implies a beta of 0.25. However, Professor Officer rounds the estimate to 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 bp, not all of the debt margin is going to reflect diversifiable risk.

Professor 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. Professor 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. Professor 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, Professor 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 gas pipeline. Professor Officer notes that the omission of a debt beta or implication that it is zero in the regulatory decisions is flawed and inconsistent with the use of a debt margin.

Professor 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, Professor Officer notes that on the basis of this Australian data, an asset beta of 0.6 is realistic for Murraylink. Professor 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 Professor Officer concludes that the best estimate for an Australian TNSP is an asset beta of 0.6.

7.10.2 Commission's Preliminary View

In its Preliminary View, the Commission determined that the appropriate asset beta was 0.4 with a corresponding equity beta of 1. The Commission's practice has been to benchmark the firm's equity beta relative to other companies or sectoral averages. The Commission has used in the past infrastructure and utilities group averages on the Australian Stock Exchange.

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.

Further, the Commission used a debt beta of zero for its Preliminary View. The Commission considered that there was no systematic default risk for a regulated entity with a guaranteed revenue stream.

7.10.3 Submissions on the Commission's Preliminary View

Submissions by interested parties

The ECCSA and EUCV notes that studies by NERA (2001), Pareto (2002), and ACG (2002) indicate that the equity beta granted by the Commission in its Preliminary View is too high. EUCV and ECCSA note that an equity beta set at 1 means that the Commission is equating MTC's risk profile at the average of all risk taking enterprises. EUCV and ECCSA are of the view a cash stable enterprise, such as a regulated transmission company has an equity beta of less than 0.5.

The EUCV and ECCSA submit that the studies noted above are relatively recent and regulators should recognise that continuing with inflated elements for CAPM formulae only continue to provide an incentive to regulated businesses to maximise its asset value and planned capex. EUCV and ECCSA note that the equity beta proposed by regulated businesses and used by regulators is too high, and recommends that the Commission reduce the equity beta to 0.4-0.5.

MTC's response to submissions by interested parties

MTC notes that the Commission has applied an equity beta of 1 in its Queensland, South Australian, and Victorian revenue cap decision, an equity beta of just over 1 in its NSW revenue cap decisions. MTC notes that it expects that the Commission's final determination to be consistent with its Preliminary View.

7.10.4 Commission's considerations

The Commission notes that in previous revenue cap decisions, an equity beta estimate of 1 was adopted. 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.

In regard to the asset beta, the Commission notes 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 7.3 outlines the approach taken in recent regulatory decisions in relation to asset betas for electricity and gas. Accordingly the Commission proposes to maintain the asset beta at 0.4 for this Decision.

Table 7.3 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

The Commission also notes that a debt beta estimate of zero has been applied in its previous electricity regulatory decisions. The Commission, in the past, considered that as the systematic risk of debt is low, given the risk of debt is primarily related to default risk, then a relatively low debt beta is appropriate and as such treated the debt beta as a residual parameter. A report prepared by the ACG for the Commission also considered this information and suggested that an appropriate range for the debt margin would be between zero and 0.15.[66] Nonetheless, as long as there is consistency in the value of the debt beta between the de-levering and re-levering process, its effect on the equity beta is generally negligible.

Consistent with previous practices, the Commission considers that an appropriate value for the debt beta is zero, in the de/re-levering process. A debt beta of zero coupled with an asset beta of 0.4, in accordance with the Monkhouse formula, provides a re-levered equity beta of 1.0.

Further, the ACG report suggested an equity beta for Australian gas transmission companies of just below 0.7 based exclusively on market evidence. ACG also considered that the data for comparable business in the USA, 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. The ACG report states:

> "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." (p42)

[66] The Allen Consulting Group, *Empirical evidence on proxy beta values for regulated gas transmission activities,* final report for the ACCC, July 2002.

ACG recommended that a conservative approach to beta estimation be retained by Australian regulators with an equity beta of 1.0. ACG states:

> "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." (p 43)

The Commission considers that it may be premature to rely on market data exclusively when determining the equity beta. Accordingly for this Decision the Commission considers than an equity beta of 1.0, while biased in favour of the service provider, is appropriate for MTC. The Commission is currently considering the merits of relying more on market data in determining an estimate of the proxy beta for TNSPs, and thus future decisions may incorporate equity betas, which are more reflective of market information.

Commission's Decision

Consistent with previous practices, the Commission considers that an appropriate value for the debt beta is zero, in the de/re-levering process. A debt beta of zero coupled with an asset beta of 0.4, in accordance with the Monkhouse formula, provides a re-levered equity beta of 1.0.

7.11 Treatment of taxation

The effective tax rate is defined as the 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.

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[67]. 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.

[67] 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).

7.11.1 MTC's application

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

7.11.2 Commission's Preliminary View

Based on the Commission's approach to modelling the effective tax rate, the Commission derived an effective tax rate of 21.29 per cent for its Preliminary View.

7.11.3 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 21.29 per cent, which was derived from the financial model.

Commission's Decision

For this Decision, the Commission will adopt an effective tax rate of 21.29 per cent. This is derived from the Commission's financial model.

7.12 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 7.4 below.

Table 7.4 Comparison of cost of capital parameters proposed by the Commission

Parameters	MTC's proposal	Preliminary View	Final Decision
Gearing ratio (D/V) %	60%	60%	60%
Asset beta β_a	0.60	0.4	0.4
Debt beta	0.2	0	0
Equity beta	1.13	1.00	1.00
Debt margin (over R_f) %	1.50%	1.45%	0.86%
Market risk premium (R_m-R_f) %	6.00%	6.00%	6.00%
Nominal risk free interest rate (R_f)%	5.4%	5.19%	5.46%
Expected inflation rate (F) %	2.2%	2.11%	2.07%
Cost of debt R_d = R_f + debt margin %	6.90%	6.64%	6.32%
Value of imputation credit	45%	50%	50%
Nominal post tax return on equity	12.15%	11.17%	11.44%
Post tax nominal WACC	6.97%	6.74%	6.69%
Pre tax nominal WACC	9.96%	8.96%	8.91%
Pre tax Real WACC	7.76%	6.72%	6.7%
Vanilla WACC	9.00%	8.45%	8.37%

Commission's decision

The Commission has calculated a post tax nominal return on equity of 11.44 per cent

8 Total revenue

8.1 Introduction

The previous chapters discussed each of the major elements of the Commission's building block approach to setting 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.

The remainder of this chapter:

- sets out the requirements of the code (section 8.2);
- summarises the Commission's decision concerning the appropriate length of the regulatory control period to adopt for MTC as well as the information considered by the Commission in arriving at its conclusion (section 8.3);
- summarises the components of the building block approach (section 8.4);
- summarises the MAR requested by MTC (section 8.5);
- summarises the Commission's assessment of the building block components (section 8.6). This includes:
  - asset value (section 8.6.1);
  - capital expenditure (section 8.6.2);
  - depreciation (section 8.6.3);
  - WACC (section 8.6.4);
  - Asset roll forward (section 8.6.5);
  - opex (section 8.6.6);
  - estimated tax payable (section 8.6.7);
  - Murraylink's total revenue over the regulatory control period, and CPI- X smoothing (section 8.6.8); and
- The Commission's conclusion (section 8.7)

8.2 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 with the coordinating TNSPs in the regions where the Murraylink interconnector is geographically located, ElectraNet and VENCorp, 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.

8.3 The regulatory control period

8.3.1 MTC's application

In its application, MTC proposes a regulatory control period of 10-years. It states that a 10 year period is appropriate for the Murraylink interconnector due to the absence of capital expenditure (capex) and a forecast for "highly efficient" opex activity for the next 10 years and beyond. MTC also contends that deferring the regulatory reset for 10 years instead of 5 years would result in significant savings for the Commission, MTC, and MTC participants.

In addition, MTC argues that a regulatory period of 10 years provides certainty that encourages private sector investment and attracts new entrants to the NEM. It notes that 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. Therefore, MTC proposes that its revenue cap commence from the date of the Commission's final decision and expire in December 2012.

8.3.2 Commission's Preliminary View

In its Preliminary View, the Commission was of the view that MTC's proposal for a 10 year regulatory period was justified given such matters as the decrease in the opex allowance proposed by the Commission (which was based on Alternative 3), Murraylink was already built and the Commission's proposed asset base was significantly lower than the actual capital cost of Murraylink, and the proposed capex program was small.

Therefore, the Commission was of the view that there appeared to be limited scope for efficiency gains in opex or capex. The Commission proposed a regulatory control period, slightly less then 10 years, and proposed to provide MTC with a half year revenue stream in 2013 to align MTC's regulatory control period with the regulatory control period of other TNSPs.

8.3.3 Submissions by interested parties on the Preliminary View

ElectraNet supports the principle that a longer control period (eg 10 years) provides greater certainty and encourages private sector investment. However, it notes that the Commission should be consistent in its future revenue cap decisions for other TNSPs.

TransGrid notes that regulation must be transparent and applied equitably and consistently across all regulated entities. It notes that the approach adopted by the

Commission in its Preliminary View to issues such as the calculation of WACC and the length of the regulatory control period must also apply to existing TNSPs.

ESIPC is of the view that given the uncertainty surrounding Murraylink's transfer capacity, particularly in NSW, and the operational performance of Murraylink in a regulated environment, the standard 5 year regulatory control period would be appropriate.

8.3.4 Commission's considerations

The Commission notes that clause 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.

The Commission notes comments by interested parties that the Commission should set a revenue control period based on consistency with its previous revenue cap decisions and that if the Commission implements a 10-year regulatory period for MTC, and then it should apply to existing TNSPs in future revenue caps.

Section 9 of the Commission's *Draft Regulatory Principles* states that the Commission will conduct reviews of the TNSP's revenue every 5 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 5 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. Such provisions in the *Draft Regulatory Principles* have applied to all TNSPs.

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 Decision 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 were 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.

The Commission notes comments by interested parties to MTC's application that a longer regulatory period would provide the Commission with limited scope for optimisation if future circumstances change and this will expose end-users to optimisation risk for twice the normal period. 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. The *Draft Regulatory Principles* states that in extending the regulatory period, one of the factors it would take into consideration is the expected size of future efficiency gains. The Commission notes that MTC submits that it 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 is of the view that the magnitude of the efficiency gains achieved over the period can be expected to be low. The Commission notes that Murraylink is already built, and so there appears to be little scope for future efficiency gains on its capital costs given that the Commission has adopted an opening asset value for Murraylink equivalent to Alternative 3, which is substantially below Murraylink's actual construction costs. The Commission notes that unlike other regulated TNSPs which operate and/or own a transmission network within a region, in which there is uncertainty surrounding its substantial proposed capex and/or opex programs at the time of its revenue resets, the proposed regulatory asset value of Murraylink is the initial regulatory asset base of MTC.

Furthermore, the Commission has provided an opex allowance based on Alternative 3, which is significantly below that requested by MTC. In addition, the Commission has removed the capex allowance it provided to MTC in its Preliminary View for the proposed augmentations given that such works will not form part of MTC regulated capex program as they constitute augmentations to the shared transmission network in Victoria. The Commission has been advised that the proposed augmentations would need to go through a tendering process run by VENCorp or if VENCorp believes that the works are not contestable then it will negotiate with SPI PowerNet, the incumbent transmission asset owner in Victoria. Therefore, the Commission is of the view that there is limited prospect that efficiency gains will drive opex costs below those proposed by the Commission. The Commission also notes that there is no capex program constituting part of MTC's revenue cap.

The Commission notes comments by ESIPC that a 5 year regulatory period should be granted given the uncertainty surrounding Murraylink's transfer capability and operational performance. The Commission further notes, in references to advise from MTC and studies provided by VENCorp that show Murraylink can deliver a 220 MW transfer with the augmentations to the Victorian network in place. Furthermore, the Commission's Service Standard principles will provide incentives on Murraylink's operational performance. Thus, in this instance given the limited scope in efficiency gains there are advantages in deferring the regulatory reset for 10 years instead of 5 years as it would result in regulatory cost savings and certainty for MTC. However, the Commission considers that extending the regulatory period beyond 10 years is not appropriate in this instance.

The Commission notes that a number of interested parties in response to MTC's application suggested that the Commission reserve the right to reopen the revenue cap. The Commission notes that it has previously stated in the *Draft Regulatory Principles* that:

> "…Implementing within period reviews would lead to increased regulatory risk and could conflict with the principle of regulatory predictability. The Commission proposes that regulatory recontracting should only occur where the benefits of such intervention outweigh the costs. The Commission considers that in general the trigger for initiating a within period review …(include) where the information provided to the Commission is found to have been

false or misleading, a material error was made in the regulatory decision, or there is a change of ownership and this may materially change the revenue requirements" (section 9, DRP)

Furthermore, the code under clause 6.2.4(d) sets out the circumstances in which a revenue cap can be reopened.

On the basis of the information provided to the Commission, 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.

Commission's Decision

Based on the information provided to the Commission by MTC and other interested parties, it is of the view that MTC's proposal for a 10 year regulatory period is justified. The Commission notes that the regulatory period provided is slightly below 10 years.

8.4 The accrual building block approach

The Commission's decision on MTC's MAR relies on the accrual building block approach. 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 = (allowed revenue) + (financial incentive)

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

where:

- MAR = maximum allowed revenue;
- AR = allowed revenue;
- S = service standards factor;
- t = regulatory period; and
- ct = calendar year.

8.5 MTC's application

In its application, MTC proposes that the calculation of the revenue, upon conversion occurring, be determined 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.

A summary of MTC's "raw" and smoothed proposed revenue is presented below.

Table 8.1 Revenue Requirement, 2003 to 2012 (nominal $m)[68]

	Calendar year 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.

8.6 The Commission's assessment of the 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.

8.6.1 Asset value

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 WACC based on the most recent financial information.

[68] Source: MTP forecasts.

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.

The Commission considers in line with its regulatory test assessment, Alternative 3 is the project which maximises the net present value of the market benefits under the regulatory test assessment, and therefore will be Murraylink's opening asset value.

Since the Commission's Preliminary View, it has received information from interested parties that highlights that in a network where interconnectors are operating in parallel to another, a PST is required to facilitate the transfer, and as such a PST has been included as part of the cost of Alternative 3. On the other hand, the Commission has replaced the SVC as proposed by BRW with a smaller version, and has made reductions to Alternative 3 to reflect spares set at 1 per cent of switchyard costs and replaced a spare PST with a spare standard transformer. The Commission has made adjustments to the contingency allowance and interest during construction to account for the capital cost decrease. Therefore, the Commission considers that MTC's opening asset value is $97.33 million (at 1 October 2003$).

In terms of modelling the movement in MTC's asset value over the regulatory period, the Commission has, for the purposes of this decision, indexed this opening asset value by 2.07 per cent per annum, which is consistent with the inflationary expectations used in deriving the WACC.

8.6.2 Capital expenditure

The Commission removed the capex allowance granted in its Preliminary View to MTC for augmentations proposed in its application. It has come to this view following advice from both VENCorp and SPI PowerNet which notes that as these works constitute augmentations to the shared transmission network in Victoria they should not form part of MTC's regulated capex program and should be undertaking in accordance with the normal practices and procedures for network augmentations in Victoria. MTC supports this view. The Commission is of the understanding that the cost of the augmentations can be recovered by VENCorp in accordance with the derogations covering the Victorian arrangements.

Under the Victorian arrangements, the proposed augmentations to the Victorian network must follow the procedures set out in VENCorp's electricity transmission license issued by the ESC. Under such arrangements, the augmentations would need to go through a contestable process run by VENCorp. The successful tenderer would typically build, own and operate the assets and enter into a long-term agreement with VENCorp for the provision of the network service. On the other hand, in the event that VENCorp does not believe that the project is contestable, it may apply to the ESC for an exemption and approval to negotiate with SPI PowerNet, the incumbent asset owner, for the works to be undertaken on a non-contestable basis.

While the Commission has deducted the augmentation allowance from MTC's revenue streams for reasons outlined above, the augmentations have been assessed as part of the Commission's regulatory test assessment. The Commission is of the view that if augmentations to the existing transmission network are included in the Murraylink project and factored into the regulatory test assessment, and if the Murraylink project as a whole satisfies the regulatory test, then the augmentations should also be treated as having satisfied the regulatory test. This is consistent with the findings of the Victorian Supreme Court on the SNI appeal who agreed with the decision of the National Electricity Tribunal in this regard.

8.6.3 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 regulatory period (table 8.3) and for determining the return of capital (table 8.4). Calculation of the applicable straight-line depreciation component has been based on the remaining life per asset class.

In its Preliminary View, the Commission considered that as it adopted Alternative 3 (an AC link) as MTC's opening asset value. To be consistent the Commission adopted the asset lives of Alternative 3 rather than the asset lives of Murraylink (a DC link).

In response ACG, states that:

> "The role of the regulatory depreciation allowance…is to return [the ORDC] to the investor in the regulated asset over its life. If a life in excess of the economic life of the actual asset is used to determine the depreciation allowance, then the whole of the investment would not be expected to be recovered over its life, and hence the expected present value of the income stream would be below the regulatory asset value."[69](page 25)

The Commission still remains of the view that the approach it adopted in its Preliminary View is appropriate and consistent with the outcomes of the Commission's regulatory test assessment. Under the Commission's regulatory test assessment, Alternative 3 maximised the net present value of the market benefits and therefore the Commission will adopt the asset lives of Alternative 3 in determining Murraylink's depreciation allowance.

The Commission considers that the Murraylink asset consists of three asset classes, which are presented in the table below, along with the asset lives adopted for the purposes of determining the depreciation allowance. The Commission notes that development costs (excluding easements), interest during construction, contingency

[69] *Submission in response to Preliminary View*, MTC, 18 July 2003.

allowance, and 10 per cent profit and overhead allowance have been proportionally distributed over switchyard and transmission line costs.

Table 8.2: Initial regulatory asset value of Alternative 3

Asset classes	Asset value ($m)	Asset lives (years)
Switchyard costs	53.47	40
Transmission line costs	39.78	50
Easements	4.08	n/a
	97.33	

On the basis of the approach outlined above, the Commission has calculated a straight-line depreciation allowance of $0.11 million for a nine month period commencing 1 October 2003 to 30 June 2004, and trends from $0.20 million to $0.25 million, $0.30 million, $0.35 million, $0.41 million, $0.47 million, $0.53 million, $0.59 million, and $0.65 million in each of the following full financial years.

8.6.4 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 11.44 per cent, which equates to a post-tax nominal vanilla WACC of 8.37 per cent. In arriving at those figures, the Commission has adopted:

- a nominal risk free interest rate of 5.46 per cent, reflecting the short term average yield on 10-year Commonwealth Government bonds;
- a real risk free rate of 3.32 per cent based on the short term average yield on 10-year capital indexed bonds;
- an expected inflation rate of 2.07 per cent derived from the difference between the two yields; and
- a debt margin of 086 per cent above the nominal risk free interest rate leading to a nominal pre-tax cost of debt of 6.32 per cent.

The Commission's chosen post tax nominal return on equity of 11.44 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.

8.6.5 Asset base roll forward

Based on the above components, the Commission has modelled MTC's asset base over the regulatory period (see Table 8.3), under the post-tax nominal framework adopted by the Commission, the return on capital building block has been calculated using the nominal vanilla WACC (8.37 per cent) consistent with the post-tax WACC determined from the cost of capital parameters.

Table 8.3: MTC's return on capital, 1 October 2003 to 30 June 2013 ($ nominal million)

	Financial Year Ending 30 June									
	2003/04[1]	2004/05	2005/06	2006/07	2007/08	2008/09	2009/10	2010/11	2011/12	2012/13
Opening asset base	97.33	97.22	97.03	96.78	96.48	96.13	95.72	95.26	94.73	94.14
Economic depreciation	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65
Closing asset base	97.22	97.03	96.78	96.48	96.13	95.72	95.26	94.73	94.14	93.49
Return on capital	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89

[1] This is for a nine month period, 1 October 2003 to 30 June 2004.

8.6.6 Operating and maintenance expenses

As the Commission has adopted Alternative 3, the alternative which maximises the net present value of the market benefits under the Commission's regulatory test assessment, for the regulatory asset value of Murraylink, it will also adopt Alternative 3's opex. This approach recognises the efficient costs of operating and maintaining the assets of the optimal network, Alternative 3, which amounts to $32.71 million ($nominal) over the regulatory period.

8.6.7 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 is $0.79 million for a nine month period commencing from 1 October 2003 to 30 June 2004. The taxes payable for the first full year is estimated at $0.89 million, trending to $1.00 million for the financial year ending 30 June 2013.

8.6.8 Total revenue and CPI-X smoothing

Based on the various elements of the building block approach, the Commission proposes a smoothed revenue allowance that increases from $8.90 million for the nine month period commencing 1 October 2003 to 30 June 2004, to $11.88 million, $11.99 million, $12.09 million, $12.19 million, $12.29 million, $12.40 million, $12.50 million, $12.61 million and $12.72 million in the subsequent full financial years of the regulatory period (Table 8.4). These figures incorporate revenue smoothing based on an X smoothing factor of 1.20 per cent. That is, the MAR will increase by CPI plus 1.20 per cent in each year of the regulatory period.

Table 8.4: MTC's MAR from 1 October 2003 to 30 June 2013 ($ nominal million)

	Financial year ending 30 June									
	2003/04[1]	**2004/05**	**2005/06**	**2006/07**	**2007/08**	**2008/09**	**2009/10**	**2010/11**	**2011/12**	**2012/13**
Return on capital	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89
Return of capital	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65
Operating expenses	2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66
Estimated taxes payable	0.79	0.89	0.90	0.92	0.93	0.94	0.96	0.97	0.99	1.0
Less value of franking credit	0.39	0.44	0.45	0.46	0.47	0.47	0.48	0.49	0.49	0.5
Unadjusted revenue allowance	8.90	11.88	11.99	12.09	12.20	12.30	12.40	12.50	12.60	12.69
Smoothed MAR	**8.90**	**11.88**	**11.99**	**12.09**	**12.19**	**12.29**	**12.40**	**12.50**	**12.61**	**12.72**

In arriving at its Decision, 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 regulatory asset value 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.

The table below illustrates the comparison between the Commission's Final Decision with its Preliminary View and MTC's application.

Table 8.5 Comparison of Final Decision with Preliminary View and MTC's Application

		2003[1]	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013[2]
Opex	**MTC**	2.19	4.37	4.47	4.46	5.91	4.44	4.44	4.43	4.42	5.88	
	Pre	0.43	1.82	1.86	1.9	1.94	1.98	2.02	2.06	2.11	2.15	1.10
	Final	2.29	3.11	3.17	3.24	3.31	3.38	3.45	3.52	3.59	3.66	
Capex	**MTC**	0	0	0	0	0	0	0	0	0	0	
	Pre	0	0	0	10.26	0	0	0	0	0	0	0
	Final	0	0	0	0	0	0	0	0	0	0	
Return of capital	**MTC**	6.1	9.2	9.2	9.2	9.2	7.6	6.8	6.8	6.8	6.8	
	Pre	0.01	0.27	0.33	0.67	0.53	0.61	0.69	0.77	0.86	0.95	0.52
	Final	0.11	0.20	0.25	0.30	0.35	0.41	0.47	0.53	0.59	0.65	
Return on capital	**MTC**	10.5	15.6	15.1	14.5	14	13.4	12.9	12.4	12	11.5	
	Pre	2.42	9.67	9.64	9.62	10.43	10.38	10.33	10.27	10.21	10.14	5.03
	Final	6.11	8.14	8.12	8.10	8.07	8.04	8.01	7.97	7.93	7.89	
Smoothed MAR	**MTC**	17.2	25.5	25.2	24.9	24.6	24.3	24	23.7	23.4	23.2	
	Pre	2.97	12.25	12.49	12.74	12.99	13.25	13.51	13.78	14.05	14.33	6.95
	Final	**8.90**	**11.88**	**11.99**	**12.09**	**12.19**	**12.29**	**12.40**	**12.50**	**12.61**	**12.72**	

[1] MTC's application and the Commission's Preliminary View were based on calendar years. The Commission's Final Decision is based on financial years.
MTC's figures for 2003 are for an six month period, 1 July 2003 to 31 December 2003
The Commission's Preliminary View for 2003 was for a three month period, 1 October 2003 to 31 December 2003
The Commission's Final Decision for 2003/04 is for a nine month period, 1 October 2003 to 30 June 2004

[2] In the Commission Preliminary View, it added half a year to the regulatory control period proposed by MTC to align MTC's regulatory control period with other TNSPs. This was for a 6 month period, 1 January 2013 to 30 June 2013.

The Commission notes that the revenue proposed in this Decision is below the revenue proposed in its Preliminary View. This is due to a reduction in the opening asset value of Alternative 3, and therefore Murraylink's opening asset value, which leads to a reduction in the return of and return on capital figures; the deduction of the capex allowance granted by the Commission in its Preliminary View; and variations in the cost of capital which largely reflect the prevailing market conditions/data at the time of this final decision. This has been partly offset by an increase in the opex allowance.

8.7 Conclusion

On the basis of the Commission's forecast inflation, the Commission has determined a revenue cap for MTC of approximately $8.90 million for a nine month period commencing 1 October 2003 to 30 June 2004. The revenue cap for the first full year is $11.88 million, and trending to $12.72 million for the financial year ending 30 June 2013.

Commission's Decision

Based on the various elements of the building block approach, the Commission proposes a smoothed revenue allowance that increases from $8.90 million for the nine month period commencing 1 October 2003 to 30 June 2004, to $11.88 million, $11.99 million, $12.09 million, $12.19 million, $12.29 million, $12.40 million, $12.50 million, $12.61 million and $12.72 million in the subsequent full financial years of the regulatory period. These figures incorporate revenue smoothing based on an X smoothing factor of 1.20 per cent.

9 Service Standards

9.1 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.[70] The Commission has since released its draft service standards guidelines[71], based on SKM’s recommendation.

The remainder of this chapter:

- summarises the Commission’s decision concerning the service standards incentive scheme as well as the information considered by the Commission in arriving at that conclusion. This includes:
    - MTC’s service standards proposal (section 9.2);
    - a summary of the major findings of PB Associates’ report (section 9.3);
    - summarises the Commission Preliminary View (section 9.4);
    - summarises submissions by interested parties in response to the Preliminary View (section 9.5);
- sets out the Commission’s considerations (section 9.6); and
- presents the Commission’s conclusions in this regard (section 9.7).

9.2 MTC’s application

MTC’s application proposes a simple incentive scheme, which is similar to parts of the scheme recommended by SKM.[72] MTC proposed a single total availability

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

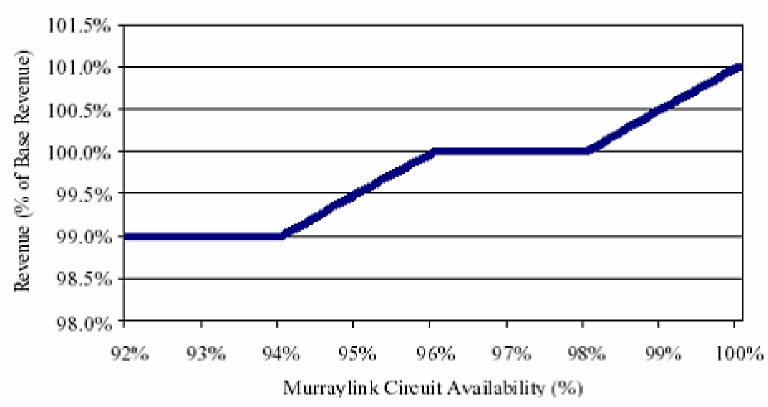
71 ACCC, *Draft decision statement of principles for the regulation of transmission revenues service standards guidelines*, 28 May 2003

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

measure, with a target of 96-98 per cent availability. Lower than 96 per cent would result in penalty and above 98 per cent would result in reward.

MTC proposed that both the penalties and rewards be capped at 1 per cent of the regulated revenue. This target was proposed for 10 years and figure 9.1 shows the scale of the penalty and rewards.

Figure 9.1: 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.

9.3 Consultant's report –PB Associates

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 9.1 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 9.1 - PB Associates recommended targets

Measure	Performance for maximum penalty (per cent)	Target performance (per cent)	Performance for maximum reward (per cent)	Weight (per cent)
Planned circuit energy availability (Figure 9.2)	99.32	99.45	99.66	40
Forced outage circuit energy availability in peak periods (Figure 9.3)	98.8	99.38	100	40
Forced outage circuit energy availability in off-peak periods (Figure 9.4)	98.8	99.40	100	20

Figure 9.2 - Planned circuit energy availability

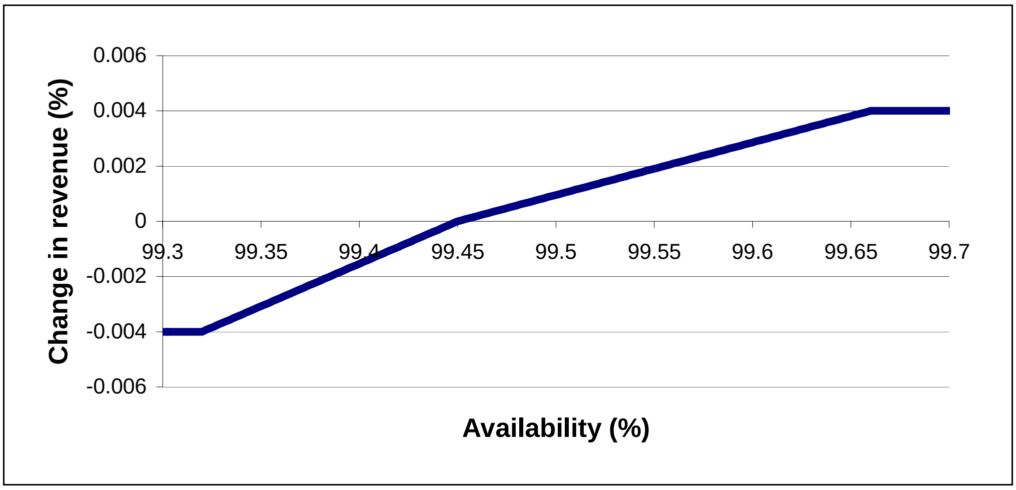


Figure 9.3 - Forced outage circuit energy availability in peak periods

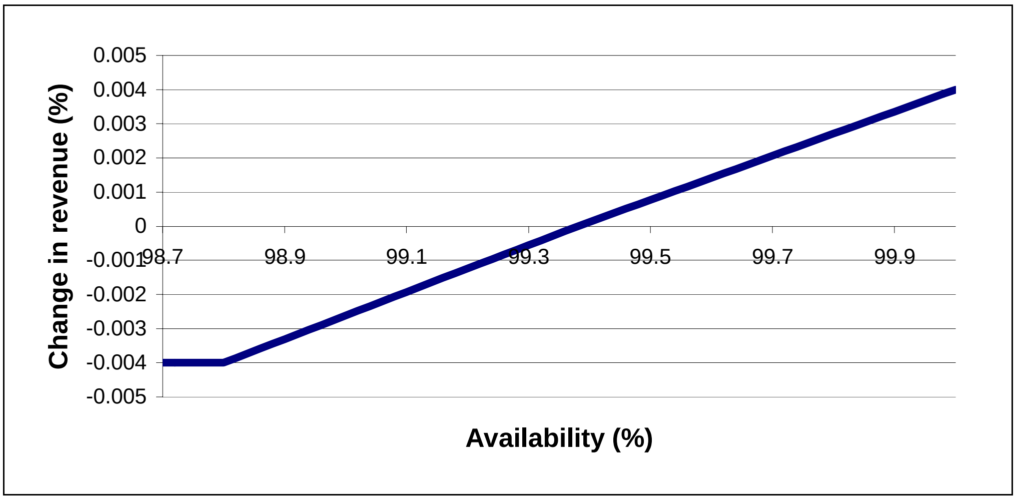
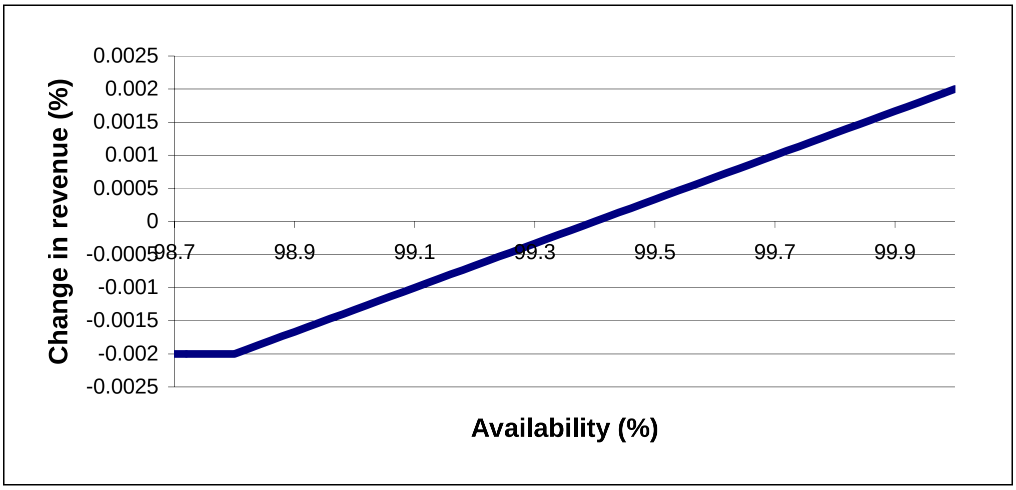


Figure 9.4 - Forced outage circuit energy availability in off-peak periods



9.4 Commission's Preliminary View

PB Associates notes that only circuit availability is required for a transmission system comprising only a single circuit interconnector and recommended 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 per cent. Given the importance of interconnectors in the NEM and the limited history of Murraylink's operations, the Commission considered PB Associates recommended performance incentive targets to be appropriate.

9.5 Submissions on the Commission's Preliminary View

9.5.1 MTC's response to the Preliminary View

MTC agreed with most of PB Associates' findings, in particular that:

- circuit availability is an appropriate service standard;
- it is appropriate to adopt the CIGRE protocol;
- annual, rather than monthly, performance incentives are appropriate;
- one per cent of revenue is an appropriate incentive; and
- a service standards review after five years is appropriate.

However MTC states that the Commission appears to have overlooked information it provided for the Commission's consideration. This information is summarised below.

- MTC's warranty requires monthly maintenance, which adds 36 hours per year to scheduled maintenance, giving a total of 84 hours per year (0.96 per cent);

- MTC believes that PB Associates overlooked factors such as time required to mobilise equipment, travel time, switching times and the minimum time required to replace a transformer; and

- MTC believes that PB Associates is mistaken in that there are 75 peak hours between 7 am and 10 pm on weekdays each week. It also states that MTC's overall circuit availability would then be 97 per cent.

Therefore, MTC continues to propose a total energy unavailability of 3.00 per cent, that is, 0.96 per cent for planned outages and 2.04 per cent for forced outages. MTC also believe that outages on Murraylink arising solely from force majeure events should be excluded.

9.5.2 Submissions from other interested parties

The Commission did not receive comments regarding the Commission proposed service standards in its Preliminary View from interested parties apart from MTC. Comments by interested parties in response to MTC's application and the Commission's Issues Paper (summarised in the Commission's Preliminary View) have been considered by the Commission in arriving at its decision on Murraylink's service standards.

9.6 Commission's considerations

PB Associates' initial 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.

Performance measures

MTC's proposal would have only provided incentives to minimise aggregate planned outages per month. It did not give any incentive for Murraylink 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 believes that planned outages need not be broken into peak and off-peak times because NEMMCO can influence what planned outages can proceed.

The Commission believes that PB Associates' recommended performance measures are appropriate for Murraylink. Particularly as it would still have to meet certain other code requirements and even state licensing requirements. These should ensure that it meets certain minimum performance measures.

Excluded events

MTC proposed that the Commission should allow 24 hours for replacing a transformer. Individual transformers should not regularly fail and require replacement.

The Commission believes that allowing 24 hours in its performance targets would distort the incentives the revenue cap can provide. In addition at the time, Murraylink may have the opportunity to replace the transformer in less than 24 hours, which makes an allowance of 24 hours inappropriate.

Therefore the Commission will exclude such an outage from the incentive scheme, if:

- Murraylink can demonstrate that the replacement of the transformer was needed;
- Murraylink can demonstrate that the time taken was needed;
- the Commission is satisfied that the replacement was the best alternative and all reasonable preventative measures had been taken; and

The Commission will also exclude force majeure events as defined in Appendix H.

Performance targets

After PB Associates completed its review for the Commission, MTC provided additional information about its required maintenance program.

MTC has provided evidence that as part of its maintenance program it requires 3 hour outages for monthly inspections. This will reduce Murraylink's planned availability.

PB Associates have provided some further comments on this information:

- two of the monthly outages should be taken during the two 24 hour outages for planned maintenance;
- another two of the outages should be taken during the allowed 100.8 hours of forced outages;
- ABB did allow "2 hours to report to site" for forced outages;
- the MTC proposal for 1.5 hours for isolation, issuing of permits, cancelling of permits and restoration is appropriate, which would add 8 hours per year to the 100.8 hours equivalent forced outage; and
- it would not be appropriate for the Commission to allow an annual amount for transformer replacement, rather it should exclude this from the forced outage statistics on a case by case basis.

Overall, PB Associates found that, given this new information, it would recommend a total of 172.8 hours of outages on Murraylink. Table 9.2 shows the availability targets that are the result of PB Associates' recommendation.

Table 9.2 Outage performance targets

Outage	Time (hours)	Availability	
Planned	72	0.9917	= 1 – 72/(365 x 24 – 100.8)
Peak forced (75/168 x 100.8)	45	0.9948	= 1 – 45/(365 x 24 – 55.8 – 72)
Off-peak forced (93/168 x 100.8)	55.8	0.9935	= 1 – 55.8/(365 x 24 - 45 – 72)
Total	**172.8**	**0.9803**	**= 1 - 172.8/(365 x 24)**

The Commission believes that PB Associates' further considerations provide improvements on the targets proposed by MTC. The Commission believes that if it allowed monthly 3 hour outages, MTC would have less incentive to undertake its monthly and half yearly maintenance in the same 24 hour outages.

Further, by only allowing for 8 outages Murraylink is provided with stronger incentives to undertake 2 of the 3 hour inspections in the 100.8 hours forced outages allowed.

Financial incentives

The Commission is satisfied, at this stage, that 1 per cent of Murraylink's revenue will provide enough incentive to motivate Murraylink to perform at high levels. The Commission has previously noted that the 1 percent cap and collar is conservative and was chosen to reflect the newness of the performance-incentive scheme in revenue caps.

The case of Murraylink is no different in this aspect, as the performance-incentive scheme is being implemented against Murraylink's revenue cap for the first time. The Commission, therefore, prefers to start at a conservative 1 per cent and change the cap as the Commission learns from the implementation of the scheme.

9.7 Conclusion

The Commission has considered MTC's proposal and its subsequent submissions, submissions from interested parties and recommendations made by PB Associates in coming to its conclusions. The Commission believes, given the 10 year regulatory period, it is appropriate to review its conclusions after 5 years.

The Commission considers that circuit availability is an appropriate performance measure for Murraylink. However, it is also appropriate to break it into three categories. These are:

- 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 1.97 per cent. The Commission's Preliminary View was cumulative unavailability of 1.77 per cent.

Therefore, the Commission has adopted performance targets (see table 9.3) to reflect some of the issues raised by Murraylink and comments made by PB Associates on these issues. The range of availability that will result in a financial incentive (rewards and penalties) is the same range that PB Associates recommended in its review of Murraylink's proposal.

Table 9.3 Performance targets

Measure	Performance for maximum penalty (per cent)	Target performance (per cent)	Performance for maximum reward (per cent)	Weight (per cent)
Planned circuit energy availability	99.04 (99.32)	99.17 (99.45)	99.38 (99.66)	40
Forced outage circuit energy availability in peak periods	98.9 (98.8)	99.48 (99.38)	100 (100)	40
Forced outage circuit energy availability in off-peak periods	98.84 (98.8)	99.34 (99.40)	99.94 (100)	20

Note the bracketed amounts are the targets from the Commission's Preliminary View.

The Commission believes that these targets are achievable by Murraylink, especially the forced outage targets given that Murraylink is a relatively new asset. These targets result in performance-incentives represented by the equations in tables 9.4, 9.5 and 9.6.

Table 9.4 Planned circuit availability

							Where:				
S_1	=	0.0040							Availability	>	99.38
S_1	=	0.0190	x	Availability	+	1.88895	99.17	<	Availability		99.38
S_1	=	0.0000							Availability	=	99.17
S_1	=	0.0308	x	Availability	+	3.05138	99.04		Availability	<	99.17
S_1	=	-0.0040							Availability	<	99.04

Table 9.5 Forced peak circuit availability

							Where:				
S_2	=	0.00400							Availability	>	100.00
S_2	=	0.00770	x	Availability	+	0.765230	99.48	<	Availability		100.00
S_2	=	0.00000							Availability	=	99.48
S_2	=	0.00690	x	Availability	+	0.686070	98.90		Availability	<	99.48
S_2	=	-0.00400							Availability	<	98.90

Table 9.6 Forced off-peak circuit availability

							Where:				
S_3	=	0.0020							Availability	>	99.94
S_3	=	0.0033	x	Availability	+	0.331130	99.34	<	Availability		99.94
S_3	=	0.0000							Availability	=	99.34
S_3	=	0.0040	x	Availability	+	0.397360	98.84		Availability	<	99.34
S_3	=	-0.0020							Availability	<	98.84

Commission's Decision:

The Commission considers that circuit availability is an appropriate performance measure for Murraylink, to be measured in the following categories:

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

Separate performance targets have been set for each category which represents a cumulative unavailability of 1.97 per cent. The Commission's Preliminary View was cumulative unavailability of 1.77 per cent.

10 Commission's Decision

Summary

MTC has advised the Commission that, subject to consideration of this decision, it intends to terminate the classification of Murraylink's network service as a market network service.

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 and its alternative projects will deliver gross market benefits ranging from $166 million to $347 million under most credible scenarios. The market simulations suggest the most credible range is between $170 million and $220 million.

Based on the ranking of the various alternative projects under the regulatory test assessment, the Commission considers that Alternative 3 satisfies the regulatory test in that it maximises the net present value of the benefit to the market having regard to its alternatives, timings and market development scenarios. The Commission will therefore use the cost of Alternative 3, $97.33 million, for the purposes of setting MTC's MAR.

The Commission will grant opex of $3 million (real) per annum, which is an opex totalling $32.71 million (nominal) over the regulatory control period. It will also allow a pass through for the following events:
- a Change in Taxes Event;
- a Service Standards Event;
- a Terrorism Event; and
- an Insurance Event.

Timing

The Commission's determination will only come into operation once Murraylink's network service ceases to be classified as a market network service. If this does not occur by the date specified in paragraph 3 of the final determination set out below, this determination will lapse and will cease to have any effect. The Commission is of the view that MTC, having indicated its intention to convert Murraylink's network service to a prescribed service, should be required to do so as soon as reasonably possible after the Commission's determination is made.

This is subject to the qualification in paragraph 4 below. If there is an application for judicial review of this decision before Murraylink's network service ceases to be classified as a market network service, this determination would almost certainly lapse before the matter was finally resolved. This means that, even if the Commission's determination ultimately stands, it would have ceased to have effect and a fresh application would be required. To overcome this the Commission has decided that, if an application for judicial review of this decision is made before Murraylink's network service ceases to be classified as a market network service, this decision will not lapse until 28 days after that application is withdrawn, dismissed or otherwise discontinued. This means that, for example, if an application for review is dismissed, MTC will have 28 days to proceed with conversion. That part of the revenue cap that has not expired would apply for the remainder of the regulatory control period.

Commission's Final Determination

Under clause 2.5.2(c) of the Code, the Commission determines that, from the time Murraylink's network service ceases to be classified as a market network service:

1. **Murraylink's network service will be a prescribed service;**

2. **MTC will have a revenue cap for a regulatory control period ending on 30 June 2013. MTC's MAR under this revenue cap will be as follows:**

Financial year	**$ million (nominal)**
2003-04 (*year commencing 1 October 2003*)	**8.90**
2004-05	**11.88**
2005-06	**11.99**
2006-07	**12.09**
2007-08	**12.19**
2008-09	**12.29**
2009-10	**12.40**
2010-11	**12.50**
2011-12	**12.61**
2012-13	**12.72**

3. **Subject to paragraph 4 below, this determination will lapse if Murraylink's network service has not ceased to be classified as a market network service on or before Tuesday, 4 November 2003;**

4. **In the event that an application is made for judicial review of this determination before Murraylink's network service has ceased to be classified as a market network service, this determination will lapse 28 days after the day on which any such application is withdrawn, dismissed, or otherwise discontinued.**

Appendix A Submissions in response to MTC's Application and Commission Issues Paper

AGL Electricity Ltd

Australian Landscape Trust

BJ Walker

C Ashton

D Fisher

D Macfarlane

D Spain

Electricity Consumer Coalition of South Australia, ElectraNet SA & Energy Users Coalition of Victoria

ElectraNet SA

Edison Mission Energy

Ergon

Essential Services Commission of South Australia

Electricity Supply Industry Planning Council (South Australia)

Energy Users Association of Australia

Energy Users Coalition of Victoria

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 Submissions in response to the Commission's Preliminary View

Department of Sustainability and Environment (Victoria)

ElectraNet SA

Electricity Supply Industry Planning Council (South Australia)

Energy Users Coalition of Victoria and Electricity Consumers Coalition of South Australia

Hon Patrick Conlon MP (South Australia Minister for Energy)

Karlene Maywald MP

Mildura Rural City Council

Ministry of Energy and Utilities NSW

Murraylink Transmission Company

National Electricity Market Management Company (NEMMCO)

Powerlink

SPI PowerNet

TransGrid

VENCorp

Western Power

Appendix C The regulatory test

The Commission has determined that the regulatory test is as follows:

A *new interconnector or an augmentation option* satisfies this 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; and
An *augmentation* satisfies this test if -

(a) in the event the *augmentation* is proposed in order to meet an objectively measurable service standard linked to the technical requirements of schedule 5.1 of the Code – the *augmentation* minimises the net present value of the *cost* of meeting those standards; or

(b) in all other cases – the augmentation maximises the net present value of the *market benefit*

having regard to a number of alternative projects, timings and market development scenarios.

For the purposes of the test:

(a) *market benefit* means 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;

(b) *cost* means the total cost of the *augmentation* to all those who produce, distribute or consume electricity in the National Electricity Market. Any requirements in notes 1 to 9, inclusive, on the methodology to be used to calculate the *market benefit* of a *proposed augmentation* should also be read as a requirement on the methodology to be used to calculate the *cost* of an *augmentation*;

(c) the net present value calculations should use a discount rate appropriate for the analysis of a private enterprise investment in the electricity sector;

(d) the calculation of the *market benefit* or *cost* should encompass sensitivity analysis with respect to the key input variables, including capital and operating costs, the discount rate and the *commissioning* date, in order to demonstrate the robustness of the analysis;

(e) a *proposed augmentation* maximises the *market benefit* if it achieves a greater *market benefit* in most (although not all) credible scenarios; and

(f) an *augmentation* minimises the *cost* if it achieves a lower *cost* in most (although not all) credible scenarios.

Notes on the methodology to be used in the regulatory test to a proposed augmentation

(1) In determining the *market benefit*, the following information should be considered:

(a) the cost of the *proposed augmentation*;

(b) reasonable forecasts of:

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*, *anticipated 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 and market network service provider projects that are augmentations consistent with the forecast demand and generation scenarios.

(c) the proponent's nominated *construction timetable* must include a *start of construction*, *construction time* and *commissioning*, where:

i. *start of construction* means the date at which construction is required to commence in order to meet the *commissioning* date, taking into consideration the *construction time* nominated by the proponent;

ii. *construction time* is the time nominated by the proponent to order equipment and build the project and does not include the time required to obtain environmental, regulatory or planning approval; and

iii. *commissioning* means the date, nominated by the proponent, on which the project is to be placed into commercial operation.

(2) In determining the *market benefit*, it should be considered whether the *proposed augmentation* will enable:

(a) a *Transmission Network Service Provider* to provide both *prescribed* and other services; or

(b) a Distribution Network Service Provider to provide both *prescribed distribution services* and other services

If it does, the costs and benefits associated with the other services should be disregarded. The allocation of costs between *prescribed* and other services must be consistent with the *Transmission Ring-Fencing Guidelines*. The allocation of costs between *prescribed distribution services* and other services must be consistent with the relevant *Distribution Ring-Fencing Guidelines*.

(3) The costs identified in determining the *market benefit* should include the cost of complying with existing and anticipated laws, regulations and administrative determinations such as those dealing with health and safety, land management and environment pollution and the abatement of pollution. An environmental tax should be treated as part of a project's cost. An environmental subsidy should be treated as part of a project's benefits or as a negative cost. Any other costs should be disregarded.

(4) In determining the *market benefit,* any benefit or cost which cannot be measured as a benefit or cost to producers, distributors and consumers of electricity in terms of financial transactions in the market should be disregarded. The allocation of costs and benefits between the electricity and other markets must be based on principles consistent with the *Transmission Ring-Fencing Guidelines* and/or *Distribution Ring-Fencing Guidelines* (as appropriate). Only direct costs and benefits (associated with a partial equilibrium analysis) should be included and any additional indirect costs or benefits (associated with a general equilibrium analysis) should be excluded from the assessment.

(5) In determining the *market benefit,* the analysis should include modelling a range of reasonable alternative market development scenarios, incorporating varying levels of demand growth at relevant load centres (reflecting demand side options), alternative project *commissioning* dates and various potential generator investments and realistic operating regimes. These scenarios may include alternative *construction timetables* as nominated by the proponent. These scenarios should include projects undertaken to ensure that relevant reliability standards are met.

These market development scenarios should include:

(a) projects, the implementation and construction of which have commenced and which have expected commissioning dates within three years (*committed projects*);

(b) projects, the planning for which is at an advanced stage and which have expected commissioning dates within 5 years (*anticipated projects*);

(c) generic generation and other investments (based on projected fuel and technology availability) which are likely to be commissioned in response to growing demand or as substitutes for existing generation plant (*modelled projects*); and

(e) any other projects identified during the consultation process.

(6) Modelled projects should be developed within market development scenarios using two approaches: ‘least-cost market development’ and ‘market-driven market development’.

(c) The least-cost market development approach includes modelled projects based on a least-cost planning approach akin to conventional central planning. The proposals to be included would be those where the net present value of benefits, such as fuel substitution and reliability increases, exceeds the costs.

(d) The market-driven market development approach mimics market processes by modelling spot price trends based on existing generation and demand and includes new generation developed on the same basis as would a private developer (where the net present value of the spot price revenue exceeds the net present value of generation costs). The forecasts of spot price tends should reflect a range of market outcomes, ranging from short run marginal cost bidding behaviour to simulations that approximate actual market bidding and prices, with power flows to be those most likely to occur under actual systems and market outcomes.

(7) In determining the *market benefit*, the *proposed augmentation* should not pre-empt nor distort potential unregulated developments including network, generation and demand side developments. To this end:

(a) a *proposed augmentation* must not be determined to satisfy this test more than 12 months before the *start of construction* date;

(b) a *proposed augmentation* will cease to satisfy this test if it has not commenced operation by 12 months after the *commissioning* date unless there has been a delay clearly due to unforeseen circumstances;

(c) unless there are exceptional circumstances, *new interconnectors* must not be determined to satisfy this test if *start of construction* is within 18 months of the project’s need being first identified in a network’s annual planning review or NEMMCO’s statement of opportunities (or in some similar published document in the period prior to 13 December 1998).

(8) The consultation process for determining whether a *proposed augmentation* satisfies this test must be an open process, with interested parties having an opportunity to provide input and understand how the benefits have been measured and how the decision has been made. Specific consultation is required on:

(a) identifying *committed projects* and *anticipated projects*;

(b) setting input assumptions such as fuel costs and load growth;

(c) modelling market behaviour and considering whether the market development scenarios are realistic;

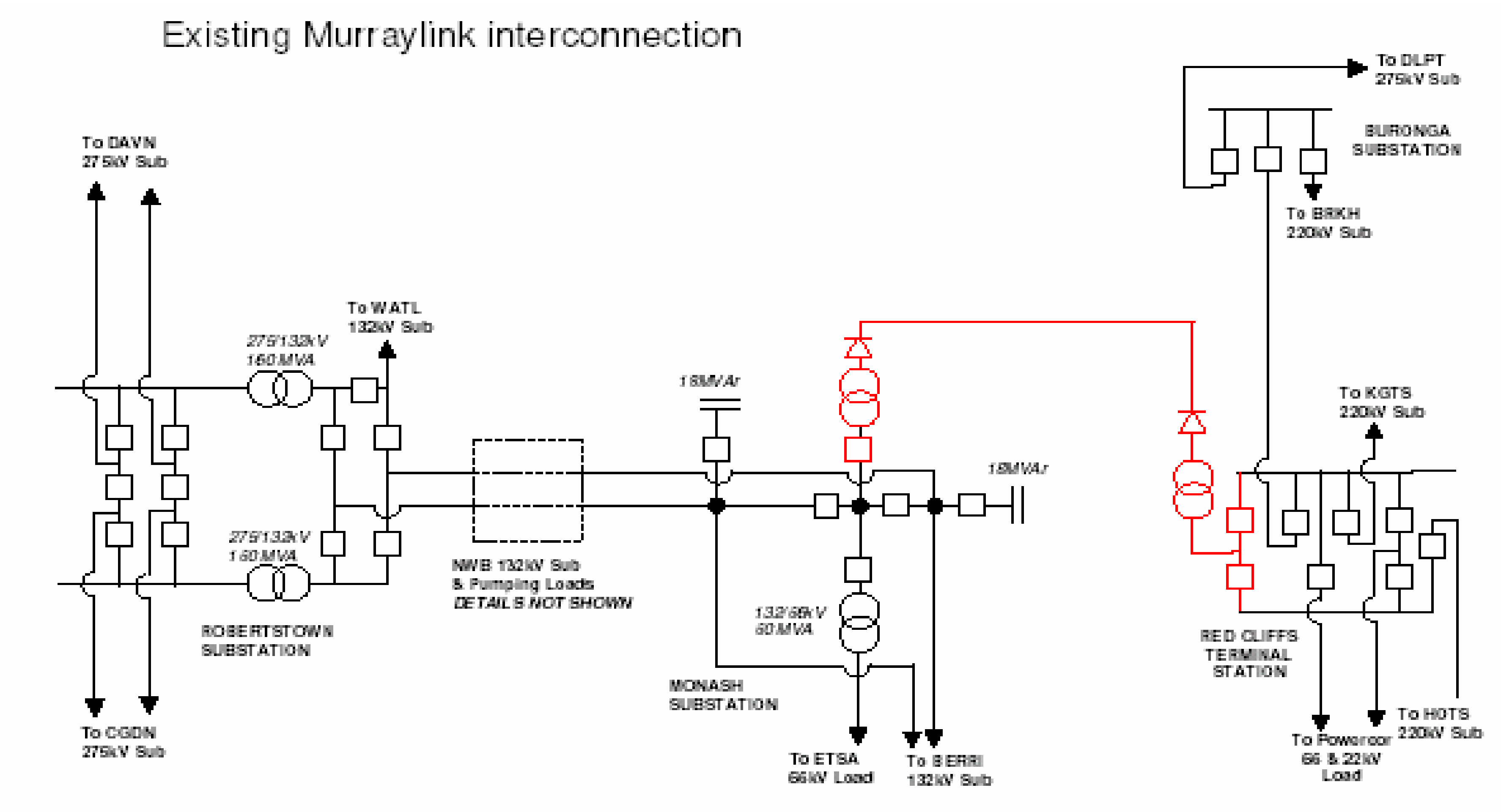
(d) the proponent's *construction timetable*;

(e) understanding how benefits will be allocated; and

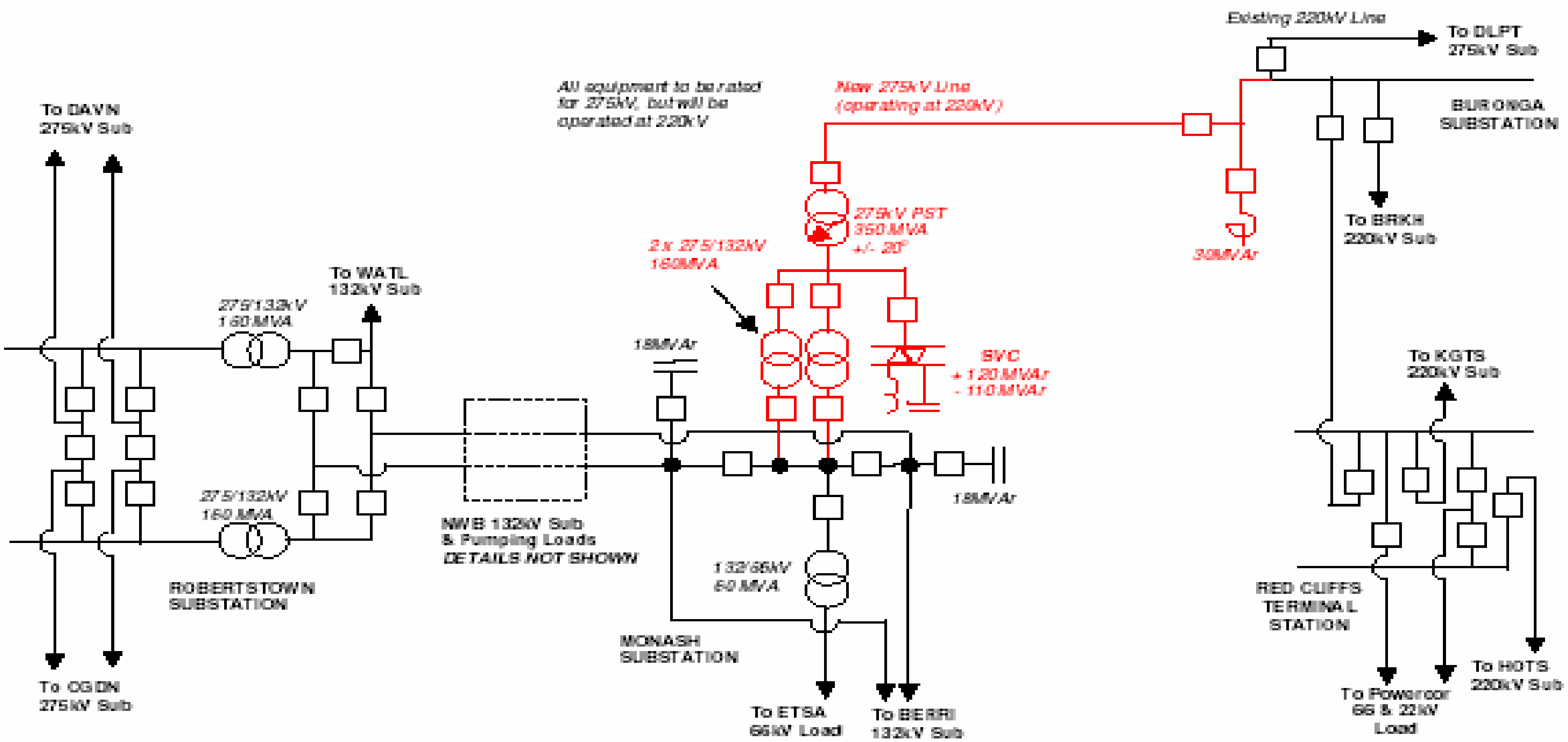
(f) understanding how a decision has been made.

(9) Any information which may have a material impact on the determination of *market benefit* and which comes to light at any time before the final decision must be considered and made available to interested parties.

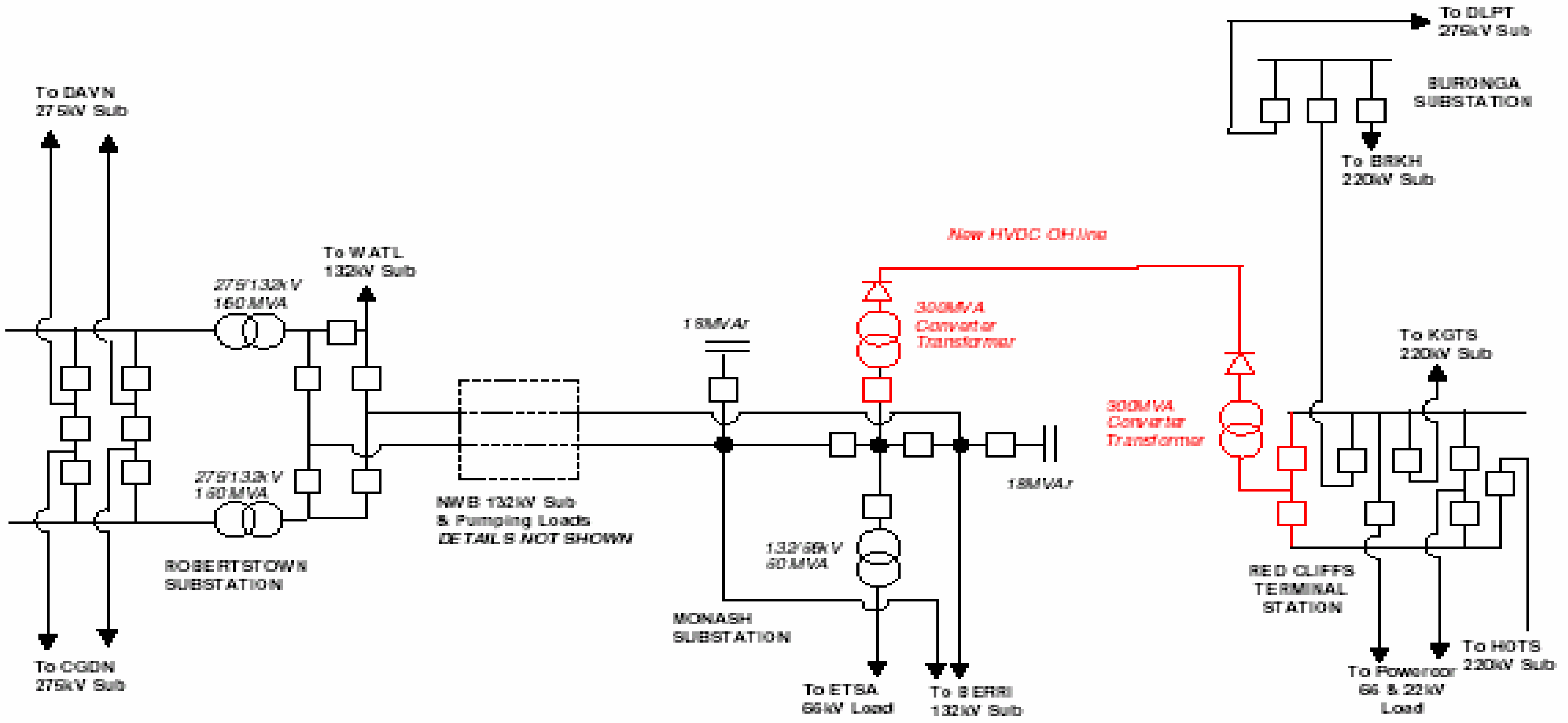
Appendix D Alternative project System Diagram and route map


Existing Murraylink interconnection
To DLPT
275kV Sub
BURONGA
SUBSTATION
To BRKH
220kV Sub
To DAVN
275kV Sub
To WATL
132kV Sub
275/132kV
160 MVA
18MVAr
To KGTS
220kV Sub
18MVAr
275/132kV
160 MVA
NWB 132kV Sub
& Pumping Loads
DETAILS NOT SHOWN
132/66kV
60 MVA
ROBERTSTOWN
SUBSTATION
MONASH
SUBSTATION
RED CLIFFS
TERMINAL
STATION
To CGDN
275kV Sub
To ETSA
66kV Load
To BERRI
132kV Sub
To Powercor
66 & 22kV
Load
To HOTS
220kV Sub

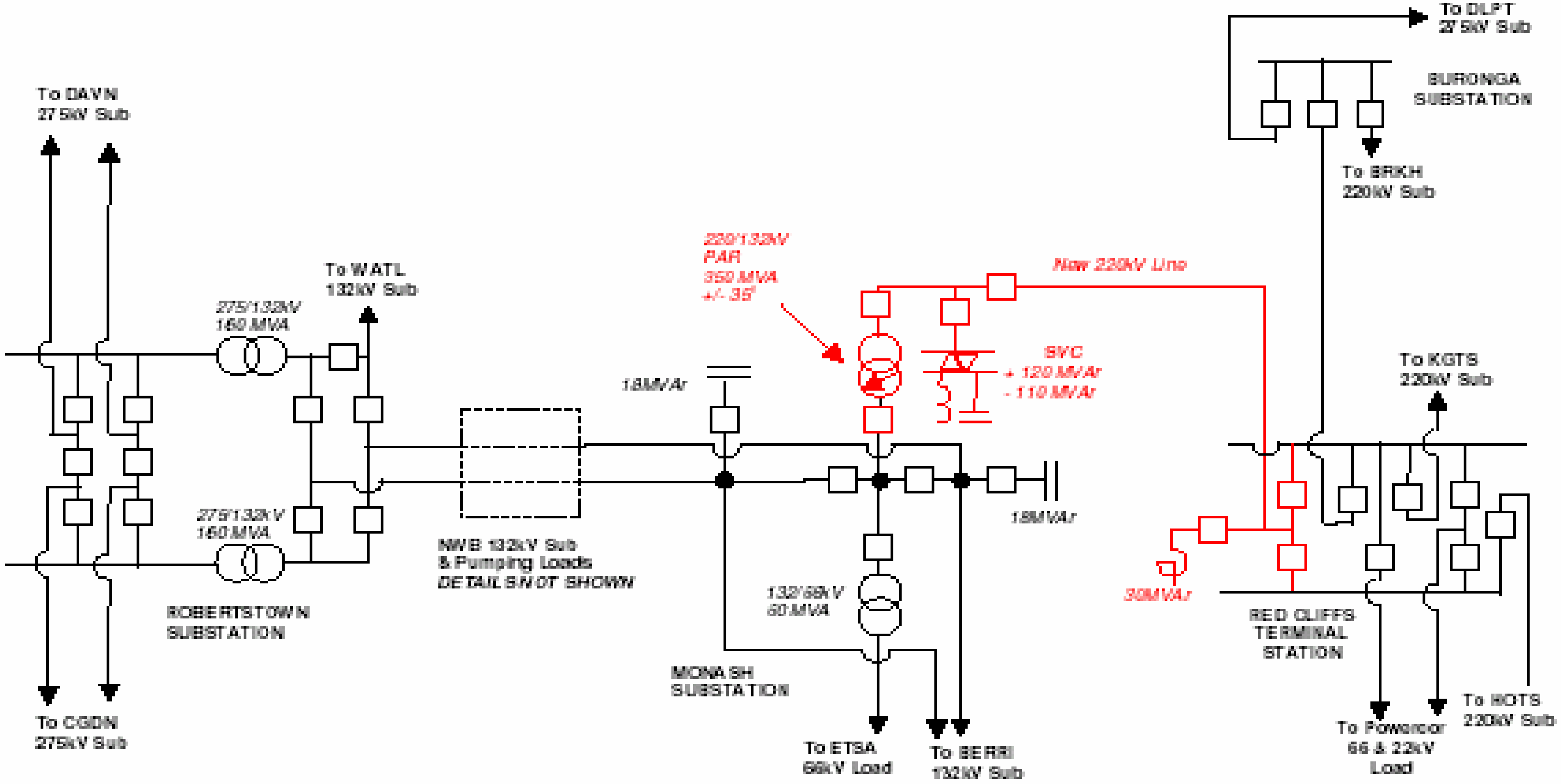
ALTERNATIVE 1 – NSW-SA 275 kV interconnection



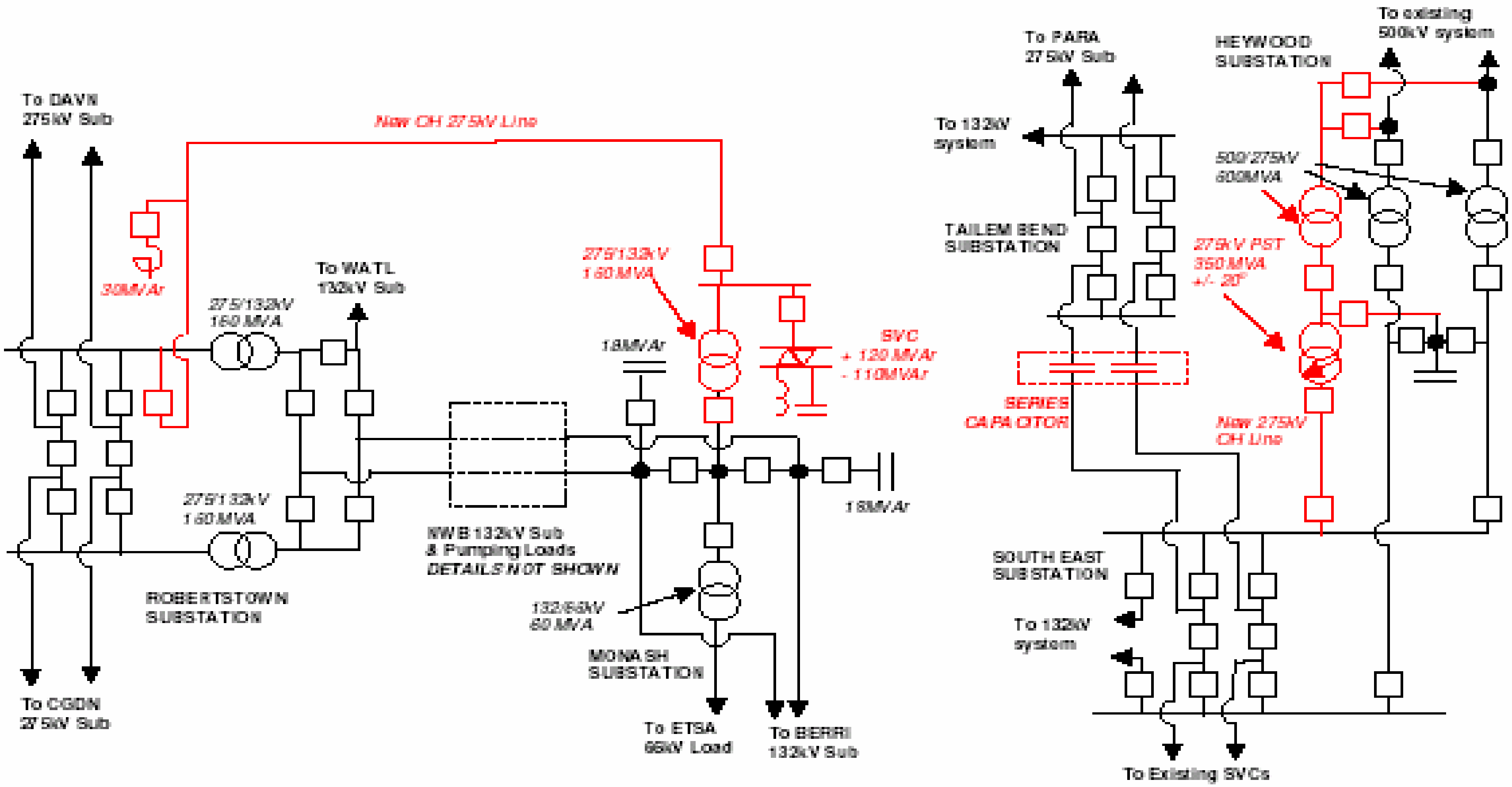
ALTERNATIVE 2 – Vic to SA HVDC interconnection with OH line



ALTERNATIVE 3 – Vic to SA 220 kV interconnection



ALTERNATIVE 4 – Riverland augmentation and Heywood upgrade



Appendix E Power transfer Capability Studies by VENCorp

The following is a guide to transfer capabilities based on a number of alternatives. These are all based on a number of assumptions set out in the notes and the following:

- Summer 2003/04 Peak Demand; and
- System Normal (i.e. all elements in service)

		Snowy – Vic	**Vic – SA**		**Snowy - SA**	**Net import into Vic/SA from Snowy**	**Net import into SA**
			HYTS	**Mlink**			
1	Existing Network	1900	500	90	N/A	1900	590
2a	Existing Network + Murraylink optimised with LTSS-WAGGA upgraded as for SNI	1920	500	220	N/A	1920	720
2b	Existing Network + Murraylink optimised with run-back for loss of MSS-DDTS	1900	500	220	N/A	1900	720
3	Existing Network + Full SNI	1990~1980	530~540	~100	110~120	2100	750
4	Existing Network + Murraylink optimised + Full SNI	1990~1980	530~540	~100	110~120	2100	750
5	Existing Network + Unbundled SNI	2080	500	150	N/A	2080	650
6	Existing Network + Murraylink optimised + Unbundled SNI	2090	500	220	N/A	2090	720
7	Existing Network without Murraylink	1900	500	N/A	N/A	1900	500
8a	Existing Network without Murraylink + Alternative 3 (No PSTs) + LTSS – WAGGA upgrade	1910	520~530	N/A	N/A	1910	630
8b	Existing Network without Murraylink + Alternative 3 (No PSTs) + trip RCTS-Monash for loss of MSS-DDTS	1900	520~530	N/A	N/A	1900	630
9a	Existing Network without Murraylink + Alternative 3 (With PSTs) + LTSS – WAGGA upgrade + **180 MVAr caps in state grid**	1920	520	N/A	N/A	1920	720
9b	Existing Network without Murraylink + Alternative 3 (With PSTs) + **180 MVAr caps in state grid** + trip RCTS-Monash for loss of MSS-DDTS	1900	520	N/A	N/A	1900	720

		Snowy – Vic	Vic – SA		Snowy - SA	Net import into Vic/SA from Snowy	Net import into SA
			HYTS	**Mlink**			
10	Existing Network without Murraylink + HYTS upgrade	1900	630	N/A	N/A	1900	630
11	Existing Network without Murraylink + HYTS upgrade + Unbundled SNI	2080	630	N/A	N/A	2080	630
12	Existing Network without Murraylink + HOTS upgrade	1900	520	N/A	N/A	1900	720

Legend:

Existing Network	Including Murraylink as an MNSP with existing run-back schemes including NSW scheme
Murraylink optimised	Includes works required on the Victorian (and NSW) network to boost the Murraylink capacity to 220MW
Full SNI	
Unbundled SNI	Refers to all SNI works excluding the Buronga – Robertstown 275kV line
Alternative 3 (No PSTs)	The option set out in the ACCC preliminary view on Murraylink regulated application, which does not include Phase Shift Transformers (i.e. 220kV overhead AC line from Redcliffs to Monash)
Alternative 3 (With PSTs)	The option set out in the ACCC preliminary view on Murraylink regulated application, including Phase Shift Transformers (i.e. 220kV overhead AC line from Redcliffs to Monash) **+ 180MVArs of shunt capacitors in state grid**
HYTS upgrade	Third HYTS transformer & series caps. 130MW at around $60M
HOTS upgrade	220MW transfer IOWG option called HOTS "A", at around $120M. Consists of a 275kV line between Horsham and Tailem Bend, 220kV lines between MLTS and BATS; and BATS & HOTS - will also require trip scheme for loss of MLTS trf.

Appendix F GMB - market development scenarios, sensitivity analysis and timing

The following table presents the gross market benefits for Murraylink and Alternatives 1, 2, 3, and 4. All options have been adjusted to take into account:

- reduction in benefits attributable to Riverland deferrals; and
- commissioning date of 1 September 2003.

The gross market benefits of Murraylink, Alternatives 1, 2, and 3 have been adjusted to take into account the timing and the approximate implementation of the augmentations to the Victoria network.

Gross market benefits of Options under market development scenarios

market development scenarios	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Low demand growth (extended low)	166	166	166	166	169
200% SRMC - Last Yr Market Simulation 2017	177	177	177	177	180
SnowVic Augmentation (in-service date 1/1/2005)	197	197	197	197	197
200% SRMC - Last Yr Market Simulation 2012	198	198	198	198	201
Base Case - medium demand growth	213	213	213	213	216
LRMC generator bidding ($10, 000MWh)	208	208	208	208	210
200% SRMC - Last Yr Market Simulation 2016	216	216	216	216	219
200% SRMC - Last Yr Market Simulation 2013	216	216	216	216	219
200% SRMC - Last Yr Market Simulation 2015	217	217	217	217	220
High demand growth	222	222	222	222	225
LRMC generator bidding ($29,600MWh)	217	217	217	217	220
Basslink (in-service date 1/1/2005)	226	226	226	226	229
200% SRMC - Last Yr Market Simulation 2018	223	223	223	223	226
200% SRMC - Last Yr Market Simulation 2014	308	308	308	308	311
commissioning date 1/01/2005 ($10,000/MWh)	187	187	187	187	187
commissioning date 1/01/2007($10,000/MWh)	176	176	176	176	176
commissioning date 1/01/2008 ($10,000/MWh)	170	170	170	170	170
commissioning date 1/01/2009 ($10,000/MWh)	153	153	153	153	153

Gross market benefits of Options under sensitivity analysis

Sensitivity Analysis	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Demand medium growth (base case)	213	213	213	213	216
Indexing VoLL	195	195	195	195	198
10% increase in merchant O&M	211	211	211	211	214
Riverland deferral - deferred 8 years	214	214	214	214	217
Riverland deferral - deferred 9 years	216	216	216	216	219
Riverland deferral -deferred 11 years	219	219	219	219	222
Riverland deferral - deferred 12 years	221	221	221	221	224
Riverland deferral costs - high costs of Riverland augmentation	221	221	221	221	224
Riverland deferral costs - low costs of Riverland augmentation	214	214	214	214	217
Riverland deferral O&M - 100% increase in deferred O&M	212	212	212	212	215
Riverland deferral O&M - 100% decrease in deferred O&M	211	211	211	211	214
Long run equilibrium -2012	210	210	210	210	213
Long run equilibrium -2013	243	243	243	243	246
Long run equilibrium -2014	236	236	236	236	239
Long run equilibrium -2015	268	268	268	268	271
Long run equilibrium -2016	241	241	241	241	244
Long run equilibrium -2017	260	260	260	260	263
Long run equilibrium - 2018	223	223	223	223	226
Discount factor - 8.25%	231	231	231	231	234
Discount factor - 9%	213	213	213	213	216
Discount factor - 10.25%	194	194	194	194	197
Reliability benefits - incorporating reliability entry plant	167	167	167	167	170
Reliability benefits - reliability entry plant to 1 July 2005	204	204	204	204	207
Base case VoLL = $29 600	334	334	334	334	337
High growth case VoLL = $29,600	347	347	347	347	350
Low growth case VoLL - $29,600	232	232	232	232	235
commissioning date 1/01/2005 ($29,600/MW/h)	303	303	303	303	303
commissioning date 1/01/2007 ($29,600/MWh)	291	291	291	291	291
commissioning date 1/01/2008 ($29,600/MWh)	283	283	283	283	283
commissioning date 1/01/2009 ($29,600/MWh)	257	257	257	257	257

Appendix G Net market benefits and ranking of Murraylink and Alternatives 1 -4

The first two tables present the net market benefits of Murraylink, Alternative 1, 2, 3 and 4 under market development scenarios and sensitivity analysis.

The net present value of the market benefits under market development scenarios

market development scenarios	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Low demand growth (extended low)	-74	-79	-25	24	3
200% SRMC - Last Yr Market Simulation 2017	-63	-68	-14	35	14
SnowVic Augmentation (in-service date 1/1/2005)	-43	-48	6	55	31
200% SRMC - Last Yr Market Simulation 2012	-42	-47	7	56	35
Base Case - medium demand growth	-27	-32	22	71	50
LRMC generator bidding ($10, 000MWh)	-32	-37	17	66	44
200% SRMC - Last Yr Market Simulation 2016	-24	-29	25	74	53
200% SRMC - Last Yr Market Simulation 2013	-24	-29	25	74	53
200% SRMC - Last Yr Market Simulation 2015	-23	-28	26	75	54
High demand growth	-18	-23	31	80	59
LRMC generator bidding ($29,600MWh)	-23	-28	26	75	54
Basslink (in-service date 1/1/2005)	-14	-19	35	84	63
200% SRMC - Last Yr Market Simulation 2018	-17	-22	32	81	60
200% SRMC - Last Yr Market Simulation 2014	68	63	117	166	145
commissioning date 1/01/2005 ($10,000/MWh)	-53	-58	-4	45	21
commissioning date 1/01/2007($10,000/MWh)	-64	-69	-15	34	10
commissioning date 1/01/2008 ($10,000/MWh)	-70	-75	-21	28	4
commissioning date 1/01/2009 ($10,000/MWh)	-87	-92	-38	11	-13

The net market benefits under sensitivity analysis

Sensitivity Analysis	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Demand medium growth (base case)	-27	-32	22	71	50
Indexing VoLL	-45	-50	4	53	32

10% increase in merchant O&M	-29	-34	20	69	48
Riverland deferral - deferred 8 years	-26	-31	23	72	51
Riverland deferral - deferred 9 years	-24	-29	25	74	53
Riverland deferral - deferred 11 years	-21	-26	28	77	56
Riverland deferral - deferred 12 years	-19	-24	30	79	58
Riverland deferral costs - high costs of Riverland augmentation	-19	-24	30	79	58
Riverland deferral costs - low costs of Riverland augmentation	-26	-31	23	72	51
Riverland deferral O&M - 100% increase in deferred O&M	-28	-33	21	70	49
Riverland deferral O&M - 100% decrease in deferred O&M	-29	-34	20	69	48
Long run equilibrium - 2012	-30	-35	19	68	47
Long run equilibrium - 2013	3	-2	52	101	80
Long run equilibrium - 2014	-4	-9	45	94	73
Long run equilibrium - 2015	28	23	77	126	105
Long run equilibrium - 2016	1	-4	50	99	78
Long run equilibrium - 2017	20	15	69	118	97
Long run equilibrium - 2018	-17	-22	32	81	60
Discount factor - 8.25%	-9	-14	40	89	68
Discount factor - 9%	-27	-32	22	71	50
Discount factor - 10.25%	-46	-51	3	52	31
Reliability benefits - incorporating reliability entry plant	-73	-78	-24	25	4
Reliability benefits - reliability entry plant to 1 July 2005	-36	-41	13	62	41
Base case VoLL = $29 600	94	89	143	192	171
High growth case VoLL = $29,600	107	102	156	205	184
Low growth case VoLL - $29,600	-8	-13	41	90	69
commissioning date 1/01/2005 ($29,600/MW/h)	63	58	112	161	137
commissioning date 1/01/2007 ($29,600/MWh)	51	46	100	149	125
commissioning date 1/01/2008	43	38	92	141	117

($29,600/MWh)					
commissioning date 1/01/2009 ($29,600/MWh)	17	12	66	115	91

The tables presented below provide the ranking of Murraylink, Alternatives 1, 2, 3, and 4 under market development scenarios and sensitivities.

Ranking of options under credible market development scenarios

market development scenarios	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Low demand growth (extended low)	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2017	4	5	3	1	2
SnowVic Augmentation (in-service date 1/1/2005)	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2012	4	5	3	1	2
Base Case - medium demand growth	4	5	3	1	2
LRMC generator bidding ($10, 000MWh)	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2016	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2013	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2015	4	5	3	1	2
High demand growth	4	5	3	1	2
LRMC generator bidding ($29,600MWh)	4	5	3	1	2
Basslink (in-service date 1/1/2005)	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2018	4	5	3	1	2
200% SRMC - Last Yr Market Simulation 2014	4	5	3	1	2
commissioning date 1/01/2005 ($10,000/MWh)	4	5	3	1	2
commissioning date 1/01/2007($10,000/MWh)	4	5	3	1	2
commissioning date 1/01/2008 ($10,000/MWh)	4	5	3	1	2
commissioning date 1/01/2009 ($10,000/MWh)	4	5	3	1	2

Ranking of options under sensitivities

Sensitivity Analysis	Murraylink	Alternative 1	Alternative 2	Alternative 3	Alternative 4
Demand medium growth (base case)	4	5	3	1	2
Indexing VoLL	4	5	3	1	2
10% increase in merchant O&M	4	5	3	1	2
Riverland deferral - deferred 8 years	4	5	3	1	2
Riverland deferral - deferred 9 years	4	5	3	1	2
Riverland deferral - deferred 11 years	4	5	3	1	2
Riverland deferral - deferred 12 years	4	5	3	1	2
Riverland deferral costs - high costs of Riverland augmentation	4	5	3	1	2
Riverland deferral costs - low costs of Riverland augmentation	4	5	3	1	2
Riverland deferral O&M - 100% increase in deferred O&M	4	5	3	1	2
Riverland deferral O&M - 100% decrease in deferred O&M	4	5	3	1	2
Long run equilibrium - 2012	4	5	3	1	2
Long run equilibrium - 2013	4	5	3	1	2
Long run equilibrium - 2014	4	5	3	1	2
Long run equilibrium - 2015	4	5	3	1	2
Long run equilibrium - 2016	4	5	3	1	2
Long run equilibrium - 2017	4	5	3	1	2
Long run equilibrium - 2018	4	5	3	1	2
Discount factor - 8.25%	4	5	3	1	2
Discount factor - 9%	4	5	3	1	2
Discount factor - 10.25%	4	5	3	1	2
Reliability benefits - incorporating reliability entry plant	4	5	3	1	2
Reliability benefits - reliability entry plant to 1 July 2005	4	5	3	1	2
Base case VoLL = $29 600	4	5	3	1	2
High growth case VoLL = $29,600	4	5	3	1	2
Low growth case VoLL - $29,600	4	5	3	1	2
commissioning date	4	5	3	1	2

1/01/2005 ($29,600/MW/h)					
commissioning date 1/01/2007 ($29,600/MWh)	4	5	3	1	2
commissioning date 1/01/2008 ($29,600/MWh)	4	5	3	1	2
commissioning date 1/01/2009 ($29,600/MWh)	4	5	3	1	2

Appendix H Force majeure events

In its past revenue cap decisions and draft service standards guidelines the Commission has excluded force majeure events from the performance-incentive scheme. Below is the definition of force majeure, which Murraylink should report on to the Commission on an annual basis. The Commission will review, amongst other things, performance results and excluded events to ensure compliance with the revenue cap decision.

The following definition is to provide guidance of what may be considered a force majeure event, rather than specifically prescribe every event that may possibly occur.

For the purpose of applying the service standards performance-incentive scheme, ‘force majeure events’ are any events, acts or circumstances or combination of events, acts and circumstances which (despite the observance of good electricity industry practice) are beyond the reasonable control of the party affected by any such event, which may include, without limitation, the following:

- fire, lightning, explosion, flood, earthquake, storm, cyclone, action of the elements, riots, civil commotion, malicious damage, natural disaster, sabotage, act of a public enemy, act of God, war (declared or undeclared), blockage, revolution, radioactive contamination, toxic or dangerous chemical contamination or force of nature

- action or inaction by a court, government agency (including denial, refusal or failure to grant any authorisation, despite timely best endeavour to obtain same) strikes, lockouts, industrial and/or labour disputes and/or difficulties, work bans, blockades or picketing

- acts or omissions (other than a failure to pay money) of a party other than the TNSP which party either is connected to or uses the high voltage grid or is directly connected to or uses a system for the supply of electricity which in turn is connected to the high voltage grid

where those acts or omissions affect the ability of the TNSP to perform its obligations under the service standard by virtue of that direct or indirect connection to or use of the high voltage grid.