REVENUE CAP APPLICATION APPENDICES

For the period 1 January 2004 to 30 June 2009

TRANSEND

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Transend's proposed revenue control

APPENDIX 1 – TRANSEND'S PROPOSED REVENUE CONTROL

OVERVIEW

Chapter 6 of this submission noted that Transend's existing revenue control annually adjusts allowed revenue to take account of differences between forecast and actual capital expenditure. This form of revenue control does not provide strong financial incentives to reduce capital expenditure. However, it ensures that customers only pay for capital expenditure that is actually incurred.

The Commission's standard approach to capital expenditure differs from Transend's existing revenue control. Under the Commission's approach, transmission revenue is not fully corrected to take account of differences between actual and forecast capital expenditure. This means that the Commission's approach provides comparatively stronger incentives to reduce capital expenditure.

For the forthcoming regulatory period, Transend proposes the adoption of a hybrid approach which builds on the best features of the standard Commission and Tasmanian approaches. The proposed 'fixed and variable' approach identifies two streams of development capital expenditure projects:

- *Fixed projects* relate to projects that are generally driven by load growth or system security requirements. Transend's analysis suggests that these projects have a very high probability of proceeding in the forthcoming regulatory period.

- *Variable projects* typically depend on specific customer-driven investments proceeding, such as new generation proposals. Transend's analysis shows that these projects will only proceed if particular scenarios eventuate.

In addition, renewal and non-network capital expenditure are also to be treated as fixed projects. It is proposed that capital expenditure related to fixed projects is treated in accordance with the Commission's standard regulatory approach. This will provide Transend with strong incentives to drive efficiency improvements in the delivery of these projects. In addition, renewal capital expenditure and non-network capital expenditure is also proposed to be treated in accordance with the Commission's standard regulatory approach.

In contrast, it is proposed that capital expenditure related to variable projects is treated in accordance with the current Tasmanian approach. This means that an adjustment mechanism will apply which requires transmission charges to reflect the actual level of *variable* capital expenditure incurred. This approach recognises that the risks associated with divergence between forecast and actual costs are not typically within Transend's control.

Transend's view is that this proposed regulatory approach provides the best mix of incentives and risk-allocation. Ultimately, it should therefore provide a better outcome for our customers.

In addition, Transend proposes that the risks associated with increases in insurance costs and network support costs are borne by customers rather than Transend. The rationale for this proposal is:

- These costs are difficult to forecast with accuracy; and
- Transend has comparatively limited control with regard to these costs;

These two conditions strongly suggest that it would not be cost effective for Transend to manage the risk that the actual costs will be higher than forecast.

The draft revenue control formulae set out below describe how these arrangements could work in practice. These draft arrangements are presented to facilitate further discussion with the Commission and interested parties, and do not necessarily reflect Transend's final views on the revenue control.

DRAFT REVENUE CONTROL ARRANGEMENTS

Transend's maximum allowed annual revenue (excluding application fees for connections and contestable connection charges) for non-contestable transmission services, in each financial year (or part thereof) during which this determination has effect, is an amount equal to the Aggregate Annual Revenue Requirement ($AARR_t$), where the $AARR_t$ is defined as follows:

For the period 1 January 2004 to 30 June 2004:

$$AARR_t = \$55.5m$$

For the period 1 July 2004 to 30 June 2009:

$$AARR_t = BASE_t + VC_t + P_{t-2} \times \left[1 + WACC_t\right] + S_{t-2} \times \left[1 + WACC_t\right] + K_t$$

Where:

$BASE_t$ refers to Transend's base annual revenue requirement[1] (which includes remuneration with respect to *fixed projects*).

For the period 1 July 2004 to 30 June 2005, $BASE_t$ is \$113.2m.

For the period 1 July 2005 to 30 June 2009 $BASE_t$ is calculated in accordance with the following formula:

$$BASE_t = BASE_{t-1} \times \frac{CPI_{t-1}}{CPI_{t-2}} \times \left(1 - X_t\right)$$

[1] Note that the 'base revenue requirement' defined in this appendix is not the same as the 'base revenue' referred to in table 10.5 and figure 10.1 in Chapter 10.

Definitions

(i) Non-contestable transmission services excludes:

a. the provision of connection services, apart from connection works that are required on Transend's existing assets or within Transend's property;

b. application fees payable by prospective or existing customers in accordance with the Tasmanian Electricity Code;

c. the provision of non-retail metering services at the generator/transmission interface; and

d. services other than transmission services.

(ii) Subscript $_{t}$ refers to the relevant financial year;

(iii) Subscript $_{t-1}$ refers to the preceding relevant financial year, and $_{t-2}$ similarly refers to the year preceding $_{t-1}$;

(iv) CPI_{t-1} is the All Capital Cities CPI December quarter for year t-1;

(v) CPI_{t-2} is the All Capital Cities CPI December quarter for year t-2;

(vi) X_t is equal to –0.0532 for all relevant financial years;

(vii) VC_t is an amount for the *variable capital expenditure projects* actually commissioned in relevant financial year t as defined in this schedule;

(viii) P_{t-2} is an amount in respect of any *pass through events* for relevant financial year t-2 (<u>including</u> the period 1 January 2004 to 30 June 2004) as defined in this schedule;

(ix) $WACC_t$ is the estimated pre-tax nominal WACC in the relevant financial year and is set at 9.4% for all relevant years;

(x) S_{t-2} is an amount in respect of service performance for relevant financial year t-2 (<u>excluding</u> the period 1 January 2004 to 30 June 2004) as defined in this schedule; and

(xi) K_t is a correction factor which adjusts revenue in each relevant financial year t for differences between Transend's maximum allowed revenue in year t-1 and Transend's actual revenue in financial year t-1, as defined in this schedule.

Calculation of VC_t

For the purposes of calculating VC_t:

Variable Capital Expenditure is defined as any capital expenditure which:
1) materially increases the power transfer capability of Transend's transmission network;
2) is required to meet security criteria; or
3) is required to facilitate a new or enhanced customer connection including increases in the capacity of exit or entry assets as a result of a customer request;

excluding capital expenditure identified as fixed capital expenditure.

Fixed Capital Expenditure is defined as expenditure relating to renewal projects, non-network capital expenditure or the completion of the projects in table 1 that are described in Appendix 6.

Table 1 – Fixed Capital Expenditure Projects

FIXED Projects
Southern augmentation (second 220kV injection point to southern network including Hobart area)
Tasmanian Wholesale Electricity Market
• Inter-company metering – Transend/Aurora connection point
• Quality of supply monitoring
• State estimator (upgrade of field equipment)
• Market systems
• Systems to ensure ongoing system security (Under frequency / Over frequency, Under voltage / Over voltage)
Norwood - Scottsdale - Derby redevelopment (supply to Aurora)
Mowbray 110/22kV substation and line development (supply to Aurora)
Risdon substation 33kV development (supply to Aurora)
Creek Road Substation 33kV connections
Reactive support program[1]
Smithton Second Circuit
George Town substation 220kV security augmentation (bus rearrangement)
Sheffield substation security augmentation (bus rearrangement)

1. Reactive support figure excludes reactive support projects at Chapel Street (assumed complete) and George Town (categorised as variable)

VC_t is calculated in accordance with the following formula (or as agreed with the Commission):

$$VC_t = [VCAB_t \times WACC_t] + DPCN_t + OPEX_t$$

Where:

$VCAB_t$ is the variable capital asset base for the relevant financial year t, calculated as follows:

$$VCAB_t = [VCAB_{t-1} + VCAPEX_t - DPCN_{t-1}]$$

where:

$VCAPEX_t$ is the total variable capital expenditure in relation to projects commissioned in relevant year t; and

$VCAB_{t-1}$ is \$Nil for the purposes of calculating $VCAB_t$ for the period 1 July 2004 to 30 June 2005.

$DPCN_{t-1}$ is \$Nil for the purposes of calculating $VCAB_t$ for the period 1 July 2004 to 30 June 2005.

$WACC_t$ is the estimated pre-tax nominal WACC in the relevant financial year and is set at 9.4% for all relevant years;

$DPCN_t$ is an amount for depreciation and is calculated as follows:

$$DPCN_t = \left[SLDCN_t \times \left(\frac{CPI_{t-1}}{CPI_{t-2}}\right)\right] - \left[VCAB_t \times \left(\frac{CPI_{t-1}}{CPI_{t-2}} - 1\right)\right]$$

Where:
$SLDCN_t$ is straight-line depreciation, is calculated in accordance with the following equation:

$$SLDCN_t = SLDCN_{t-1} + \frac{VCAPEX_t}{L_t}$$

$SLDCN_t$ is \$Nil for the purposes of calculating $DPCN_t$ for the period 1 July 2004 to 30 June 2005.

L_t is the average economic life of the assets comprising $VCAPEX_t$ as determined by Transend in accordance with the Commission's draft Statement of Regulatory Principles, and is \$Nil for the purposes of calculating $DPCN_t$ for the period 1 July 2004 to 30 June 2005.

$OPEX_t$ is an allowance for the operating expenditure associated with the *Variable Capital Expenditure* projects and is calculated as follows:

$$OPEX_t = VCAB_t \times 0.02$$

Calculation of P_{t-2}

P_{t-2} is an amount in respect of any *pass through event* for relevant financial year t-2 or part thereof. P_{t-2} is calculated by summing each cost impact (whether positive or negative) arising from the following pass-through events:

1. An insurance event.
2. A grid support event.
3. A tax change event.
4. A service standards event
5. A terrorism event.

These pass-through events are defined in schedule 1 of this appendix.

Within six months after the end of each relevant financial year, Transend must present its calculation of P_t (the pass-through costs incurred in financial year t or part thereof) to the Commission with supporting information demonstrating that the costs have been prudently incurred. The Commission can disallow any amounts which are not related to pass-though events or where costs have not been prudently incurred.

<u>With respect to pass-through costs incurred in 2007/08 and 2008/09, the Commission must provide an allowance P_t in the first and second years of the next regulatory period 2009/10 and 2010/11, according to the following formulae</u>:

$$P_t = P_{t-2} \times \left[1 + WACC_t\right]$$

Calculation of S_{t-2}

S_{t-2} is calculated according to Transend's service performance in the financial year, t-2, excluding the period 1 January 2004 to 30 June 2004. S_{t-2} is calculated as follows:

$$S_{t-2} = BASE_{t-2} \times S_{p-2}$$

Where:

S_{p-2} is calculated in accordance with the following equation:

$$S_{p-2} = S_1 + S_2 + S_3 + S_4$$

Where:

S_1 relates to transmission circuit availability (%) and is calculated as follows for each financial year t-2, excluding the period 1 January 2004 to 30 June 2004:

S_1 Transmission circuit availability (%)	**Where:**
S_1 = -0.0025	Actual availability ≤ 98.8
S_1 = 1.25 * actual availability – 1.23750	98.8 < Actual availability ≤ 99.0
S_1 = 0.0000	99.0 < Actual availability ≤ 99.1
S_1 = 1.25 * actual availability – 1.23875	99.1 < Actual availability ≤ 99.3
S_1 = 0.0025	Actual availability > 99.3

S_2 relates to transformer circuit availability (%) and is calculated as follows for financial year t-2, excluding the period 1 January 2004 to 30 June 2004::

S_2 Transformer circuit availability (%)	**Where:**
S_2 = -0.0015	Actual availability ≤ 98.8
S_2 = 0.75 * actual availability – 0.74250	98.8 < Actual availability ≤ 99.0
S_2 = 0.0000	99.0 < Actual availability ≤ 99.1
S_2 = 0.375 * actual availability – 0.371625	99.1 < Actual availability ≤ 99.5
S_2 = 0.0015	Actual availability > 99.5

S_3 relates to supply availability (%) and is calculated as follows for each financial year t-2, excluding the period 1 January 2004 to 30 June 2004::

S_3 Supply availability (%) (a) loss of supply events above 0.1 system minutes threshold	**Where**:
S_3 = -0.002	Loss of supply events ≥ 20
S_3 = - 0.0005 * loss of supply events + 0.008	16 ≤ Loss of supply events < 20
S_3 = 0.0000	14 ≤ Loss of supply events < 16
S_3 = - 0.0005 * loss of supply events + 0.007	10 ≤ Loss of supply events < 14
S_3 = 0.002	Loss of supply events < 10

S_4 also relates to supply availability (%) and is calculated as follows for each financial year t-2, excluding the period 1 January 2004 to 30 June 2004:

S_4 Supply availability (%) (b) loss of supply events above 2 system minutes threshold	**Where**:
S_3 = -0.004	Loss of supply events ≥ 5
S_3 = - 0.002 * loss of supply events + 0.006	3 ≤ Loss of supply events < 5
S_3 = 0.0000	2 ≤ Loss of supply events < 3
S_3 = - 0.002 * loss of supply events + 0.004	0 ≤ Loss of supply events < 2

A more detailed description of the service incentive scheme is provided in Appendix 4 of this submission. In particular, it provides a detailed description of how each parameter (S_1 to S_4) should be calculated for the purpose of accurately and consistently measuring Transend's performance.

<u>With respect to service performance in 2007/08 and 2008/09, the Commission must provide an allowance S_t in the first and second years of the next regulatory period 2009/10 and 2010/11, according to the following formulae</u>:

$$S_t = BASE_{t-2} \times S_{p-2} \times \left[1 + WACC_t\right]$$

Calculation of K_t

K_t is a correction factor which adjusts revenue in each relevant financial year t for differences between Transend's Aggregate Annual Revenue Requirement in year t-1 and Transend's actual revenue in financial year t-1. K_t is defined as

$$K_t = \left[AARR_{t-1} - TAR_{t-1}\right] \times [1 + WACC_t]$$

Where:

TAR_{t-1} is Transend's actual revenue in relevant financial year t-1.

It is noted that in calculating K_t, TAR_{t-1} will not be known precisely until after the commencement of financial year t. Any variation from the estimates will be recovered in the following year with an appropriate escalation.

Schedule 1 – Definition of pass-through events

An insurance event occurs in any relevant financial year if the aggregate cost of Insurance (including, without limitation, premiums and deductibles) is higher or lower than $950,000 per annum expressed in 2002-2003 prices.

A grid support event occurs in any relevant financial year if Transend incurs any costs in compensating market participants in order for Transend to obtain outages for the purpose of maintenance or capital work.

A tax change event occurs where there is:

(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 or imposition of a Relevant Tax,

to the extent that the change or imposition:

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

(ii) results in a change in the amount Transend 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 Transend's revenue cap) by way of Relevant Tax.

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 Transend in connection with the provision of transmission services; or

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

but excludes

(i) income tax (or State equivalent tax) and capital gains tax;

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

(iii) fees and charges paid or payable in respect of a Service Standards Event;

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

(v) any tax, rate, duty, charge, levy or other like or analogous impost which replaces the taxes and charges referred to in (i) to (iv).

A service standards event is a decision made by the Commission, the Tasmanian Office of the Energy Regulatory or any other Authority or any introduction of or amendment to an Applicable Law after the date of the Determination that has the effect of:

(i) imposing or varying minimum standards on Transend relating to revenue capped transmission services that are materially more or less onerous than the minimum standards applicable to Transend in respect of revenue capped transmission services at the date of the Determination; or

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

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

(iv) Transend incurring materially higher or lower costs in providing revenue capped transmission services than it would have incurred but for that event.

A terrorism event is an act of terrorism, which includes threats associated with terrorism.

APPENDIX 2

Benchmark Economics benchmarking report

TRANSEND

Benchmarking Transend

A cost structure model for transmission networks

February 2003

Benchmark Economics

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Executive Summary

This Report forms part of the submission by Transend to the Australian Competition and Consumer Commission for the 2003 price re-set. It provides empirical analysis in support of Transend's claims relating to the links between its relative cost position and its scale and business conditions. In the absence of an established cost structure framework to guide cost comparisons regulatory efficiency estimates, in our view, have tended to misinterpret the relative efficiency of Australia's networks. There is no room in Transend's current revenue allowance for misinterpretations of its cost performance. As this analysis will demonstrate, its revenues are less than that justified by the nature of its network – it has the lowest average costs of the Australian networks – despite clear disadvantages in scale and business conditions. It is likely that the traditional use of "price measures" (cost per MWh) as the basis for assessing efficient cost has obscured Transend's extremely low cost position.

While its lower costs present a short term advantage to network users, in the longer term it is questionable whether Transend's revenue allowance is adequate to the task of maintaining Tasmania's transmission system. This revenue constraint is especially relevant with the forthcoming connection to the mainland through Bass Link.

Performance comparisons are undertaken by pricing regulators to determine the capacity of the networks to achieve realistic efficiency gains in their cost structures. However, as the Judgment in the EPIC case made clear, efficient cost is an uncertain term and without an adequate foundation in economic theory:

> *"determining…the efficient level of costs or the outcome of a competitive market are matters of economic theory and practice which, on the evidence, are in the course of constant revision, development and refinement."*

Moreover, the industry itself has presented no comprehensive network cost model that could assist regulators to identify key cost drivers. One UK consultant reporting to Ofgem found there was:

> *"…little consensus on the appropriate cost driver in respect of the operating…costs of transmission companies".*

In judging efficient cost without the benefit of an agreed foundation, either economic or industry based, regulators have opted to rely on an ad hoc selection of performance indicators. As result, identified "efficiencies" have often been the outcome of the cost affects of scale or business conditions over which the network have little control – not of managerial performance. Electricity is not just another input to production in other markets; it is increasingly the single most important input in the Australian economy. Maintaining an infrastructure base able to meet the demands of the modern economy requires that it be adequately resourced. This may not be the case if revenue requirements are based on misleading performance comparisons.

Despite these difficulties, economics does offer some guidance on the nature of network costs. It is recommended that several basic principles be used as a point of reference in making cost comparisons. These principles include:

- the nature of the production process;
- the costs of production; and
- returns to scale.

The nature of the production process can guide selection of network inputs and outputs. Perusal of the empirical literature reveals that understanding of the nature of the network product is not well developed; variables such as kilometre of line are used interchangeably as inputs and outputs. If we do not know the product, it is difficult to accept that we can make valid judgements as to its "cost of production".

More questionable still has been the use of "**price measures**" to determine **cost** efficiency. The cost of production refers to the resources required to provide network outputs. It can be measured as revenue $/MW capacity, or $/network length, etc. Price, however, measured as $/MWh, only measures the use of the system, that is, the energy transported over the network provided. To judge the cost efficiency of a road construction company by the number of cars using the road would not seem prudent. It is no less so for networks and energy.

The lack of attention to economies of scale is especially interesting. Regulated pricing for electricity networks was justified on the basis of their natural monopoly characteristics in the presence of substantial economies of scale. It is therefore surprising to find that few cost studies test for the possible benefits of scale.

On the basis of these three principles, this report explores the cost performance of TNSPs in Australia. It provides important insights into the influence of economies of scale, and the impact of two business conditions; energy density and load factor. It provides an effective framework for comparing TNSPs cost performance given their particular business conditions. The report uses a series of XY charts[1] to illustrate this information.

Though the sample examined is small, certain links emerge clearly. Relative levels of assets, opex, and capex are influenced strongly by scale and business conditions. The large networks, SPI PowerNet and Transgrid, benefit from the scale of their operations and advantageous business conditions. Their performance should not be used to assess the efficiency of the other networks without adequate adjustment for these factors.

In the Australian context, average costs rise with increasing network length (reflecting the greater complexity of networks in larger systems). However, average costs decline with higher levels of capacity, providing direct evidence of the benefits of scale. To achieve meaningful efficiency comparisons by normalising costs against these outputs, length (km) or capacity (MW) is simply not possible. Large scale networks are likely to have the lowest $/MW but also the highest $/km, for example, SPI PowerNet. Any use of the "price indicator", $/MWh, as a measure of **cost** performance adds further to this confusion.

Transend's performance

Transend is Australia's smallest transmission network, with a comparatively low level of energy density and a low load factor when its total capacity is taken to account. It therefore derives no benefits from potential economies of scale or from the higher capacity utilisation associated with high energy density or load factor.

The nature of Transend's network, and therefore its cost base, is dictated largely by its hydro dominated base. The conventional use of peak capacity to measure network capacity is shown to be inappropriate for transmission networks, since they are also obligated to provide sufficient capacity to connect the system generators. This need not be the same as peak demand. Widely dispersed and with relatively low capacity factors, a hydro base has required Transend to provide a network that is 50 per cent greater than that necessary to meet the peak demand of end use customers. Use of peak demand capacity as the normaliser in cost comparisons can only provide a misleading indicator of relative performance.

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[1] Effectively, the XY charts are visual depictions of single-variable linear regressions. The trend line in most charts represents the line of best fit between the two variables. The advantage of this approach is that it makes quite clear the strength of the relationship, variability around the trend, and the position of the individual networks. Treated in this way the basis for any conclusions is readily apparent -- there is no "black box" analysis.

A comparison of Transend's performance relative to other Australian TNSPs suggests the following conclusions:

Asset valuation: The current level of assets appears low relative to Transend's scale and business conditions. Though the reasons are not clear it is possible that its aging asset base is a contributing factor

Opex: Measured against outputs, (supply side MW, and network length), Transend's level of operating expenditure is very low and ranks as one of the lowest in Australia. Given the age of its asset base this constrained level of operating and maintenance expenditure suggests closer examination of future opex levels could be justified.

Capex: The current level of capex appears justified by the scale and nature of the network. Note, however that this expenditure allowance appears, in part, to be offsetting a low opex spend. This could reflect the need to refurbish and replace and aged network

Prices: Transend ranks higher when compared on price performance. The reason is quite simple. To meet the demands of the supply side for generator connections it must invest in 2500 MW of network capacity. Yet it must recoup this outlay through charges levied on a use of the system that only averages 1150 MW and peaks at 1650 MW, just 66 per cent of its total investment.

Tasmania derives great benefit from its low cost hydro base. However, in a deregulated market the connection cost of this system is born by another business. When assessing the performance of that business, Transend, it is essential to recognise the cost implications of the hydro base.

1 Efficient costs and performance comparisons

The National Competition Policy introduced third party access and regulated pricing for monopoly networks to promote national economic growth by facilitating competition in upstream and downstream markets[2]. It was not an end in itself. To achieve this objective price regulation was to encourage efficient operation and ongoing investment in electricity networks. Implementing competition policy, the National Electricity Market Code established principles for pricing regimes that required outcomes to be cost effective; incentive based; and take into account potential efficiency gains. However, while these terms are in common usage, the Supreme Court Decision[3] in the Epic Energy case observed that:

> *"determining…the efficient level of costs or the outcome of a competitive market are matters of economic theory and practice which, on the evidence, are in the course of constant revision, development and refinement."*

As a contribution to the development and refinement of the concept of efficient cost, particularly as it applies to regulated pricing regimes, this report examines the cost structures of Australian transmission networks. Managerial efficiency can only be estimated once the effects of these cost drivers are isolated from the performance analysis.

Given its emerging role in regulatory price setting, it is surprising that the notion of ***efficiency*** for electricity networks has received little critical attention. Issues fundamental to performance comparisons are consequently not well understood. Powerlink observed in its pricing submission to the Australian Competition & Consumer Commission (ACCC) that it was unable to draw on any industry standard for measuring cost performance. In the UK, a review of transmission operating and maintenance expenditures by Arthur Andersen found there was: *"…little consensus on the appropriate cost driver in respect of the operating…costs of transmission companies"*.

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[2] National Competition Policy Review, "Hilmer Report", Canberra, 1993.

[3] Supreme Court of Western Australia – Court of Appeal: Re Michael v Epic Energy, 2002

In the absence of an established network cost structure, this report argues that estimations of potential efficiency gains in regulated price determinations would benefit greatly from the guidance offered by certain economic principles. In particular those related to the:

- production process;
- costs of production; and
- returns to scale.

The importance of identifying relevant cost drivers and the impact of the operating environment on costs cannot be stressed too greatly. Electricity is not just another input to production in other markets; it is increasingly the single most important input in the Australian economy. Maintaining an infrastructure base able to meet the demands of the modern economy requires that it be adequately resourced. This may not be the case if revenue requirements are based on misleading performance comparisons. In a recently released Staff Paper on cost factors in electricity prices, the Productivity Commission[4] observed that:

> *"The usefulness of benchmarking as a guide to relative performance depends critically on an ability to compare like with like, or to make allowance for differences in operating environment that may be outside a utility's control"*

Like with like comparisons remain elusive. Performance comparisons by regulators to assess relative levels of efficiency have drawn on an arbitrary array of indicators. In the UK, benchmarking has been based on annual rates of reduction in unit costs among *other infrastructure industries*; and unit costs measured against line length and transformer numbers in *other countries*. In Australia, efficiency measures have focused almost entirely on operating and maintenance costs (opex), despite the acknowledged potential for trade-offs between opex and capex. Indicators have included ratios of opex to asset values, throughput (GWh), capacity (MW), and line length (km). Little, if any, empirical evidence has been offered in support of the choice of indicators.

Moreover, these partial productivity measures offer few advantages in benchmarking, since they do not control for differences in scale or business conditions. Depending on the normaliser selected, performance outcomes based on partial indicators can rank as "superior" or "poor", a contradiction that provides little information to regulators or other stakeholders. Judging superior performance from the commonly used indicators opex/MW and opex/km shown in Figures 1 and 2 would be difficult since the "performance"

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[4] Sayers, C. and Shields, D. 2001, *Electricity Prices and Cost Factors,* Productivity Commission Staff Research Paper, AusInfo, Canberra, August.

rankings of the networks are largely reversed. For example, SPI Powernet ranks as least cost measured against opex/MW but highest cost when assessed against opex/km. Conversely, Transend ranks as least cost measured against opex/km but third highest measured against opex/MW.

Figure 1: Opex per capacity MW

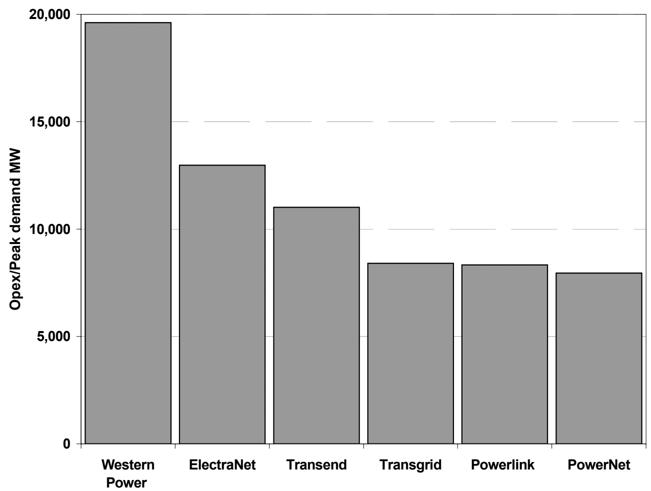
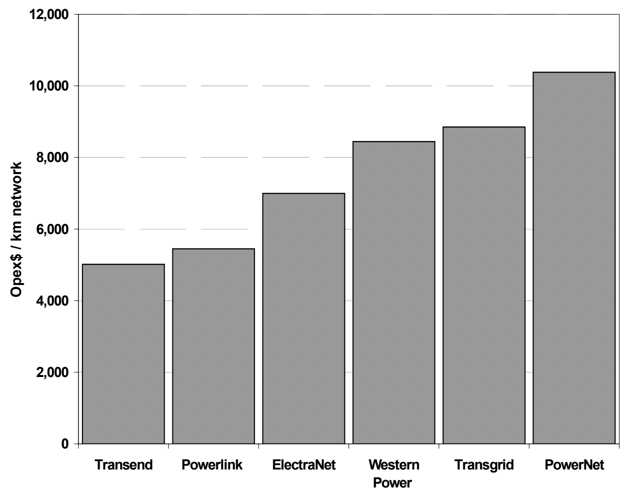


Figure 2: Opex per network km



These conflicting outcomes simply reflect the influence of individual operating conditions, not managerial efficiency. Yet, these indicators are regularly used for performance comparisons in Australian regulatory pricing determinations. To overcome the uncertainty created by conflicting outcomes of benchmarking studies Bauer, Berger, Ferrier and Humphrey[5] (1998) proposed a set of consistency conditions for use in regulatory analysis. Specifically, the consistency conditions require that efficiency scores generated by different approaches have: comparable means, standard deviations, and other distributional properties; institutions should rank in

[5] Bauer, Paul W. Berger, Allen N., Ferrier, Gary D, and Humphrey, David B. (1998) "Consistency conditions for regulatory analysis of financial institutions: a comparison of frontier efficiency methods", *Journal of Economics and Business,* 50, pp 85-114.

approximately the same order; and the same institutions should mostly be identified as “best practice” or “worst practice”. The partial indicators in Figure 1 would not meet these conditions.

This report is structured as follows. Section 2 provides a context for network cost analysis by outlining a number of economic principles relevant to the analysis. Section 3 explores the cost structures of Australian businesses in the context of the principles discussed in section 2, commencing with an overview of the relative position of the Australian transmission networks. This is followed by some brief concluding comments in Section 4.

2 Economics for network cost analysis

"The transmission regulation framework outlined in the Draft Regulatory Principles is an accrual building block approach based on forecast of the ***cost of service"*** *ACCC Draft Statement of Regulatory Principles*

Understanding the implications of this simple statement is central to an accurate assessment of network cost performance. For reasons that are not always clear, the terms "cost" and "service" in the context of transmission network analysis are often misinterpreted. Economic theory, however, can provide useful guidance in defining both the nature of the network ***service*** and the ***cost*** of providing it.

2.1 Defining the network service:

In constructing network cost models one of the most difficult tasks facing analysts appears to have been the identification of inputs and outputs to describe the network *service*. One review of the empirical literature[6] has found that variables have been used interchangeably either as inputs or outputs. For example, in some models line length is used to represent capital inputs, in others it is considered an output representing the transport function of the network service. Uncertainly as to the nature of the product must call into question conclusions regarding its "cost of production".

In economics, the production process describes the way in which firms transform purchased inputs (the factors of production) into outputs. One example cited in text books is the bakery which uses *inputs* including labour and raw materials such as flour and sugar and capital invested in ovens to produce *outputs* such as bread and cakes. The proportion of labour, raw materials and capital will be influenced by relative prices, and availability of resources, for example skilled labour. The ratio of inputs to outputs will be affected by factors including scale of output, certain business conditions, and managerial efficiency.

[6] Kaufmann, L & Beardow, M, "

This simple concept guides selection of network outputs: they are those products or services resourced by paid inputs and represent the *transformation* of paid inputs. On the face of it this definition appears self-evident. Nevertheless, it is accepted practice in cost analysis to define network output as the energy transported (MWh). Energy, however, is not the outcome of the transformation of wires and towers, it is the commodity transported along the network provided. It is more akin to the cars on a road or carriages on a railway. To judge the cost efficiency of a road construction company by the number of cars travelling along the road would not seem prudent.

2.2 The transmission production process

Transmission networks provide a high voltage *connection* service between generators and the distribution network for the transport of electricity by others to end-users. Transmission connection has two components. On the supply side, it provides access for the generators to the wholesale market. On the demand side it provides retailers with access from the wholesale pool to the low voltage network for retailing of energy to customers located at varying locations within the network franchise.

In terms of the production process, network inputs are wires, towers, transformers and substations. Measured in terms of financial flows in the building block approach to revenue (cost) setting the inputs are, variously, operating and maintenance expenditures, capital expenditure, and the rate of return on, and of, capital.

Network outputs are more complex. Network output is not a single discrete product but a bundle of services addressing a range of market requirements. In addition to the length of the network required to connect sellers to buyers, networks must also meet certain capacity requirements: the capacity required on the supply side to enable generators to access the market and on the demand side the peak capacity required by end-users. In connecting generators to the grid, network service providers must also reduce the voltage of energy delivered to the generator bus bars to the levels required at the distribution supply points. As an essential facility, electricity network businesses are also expected to design and operate networks to assure reliable deliveries.

Accordingly, network service providers transform capital and other inputs into the following outputs:

- *Connectivity* the extent of the network from the generators to bulk supply points, represented in the model as line length km.
- *Capacity* on the supply side it is the capability to accept the capacity of generation installed, on the demand side it is the level of peak demand, represented in the model a generator capacity MW;

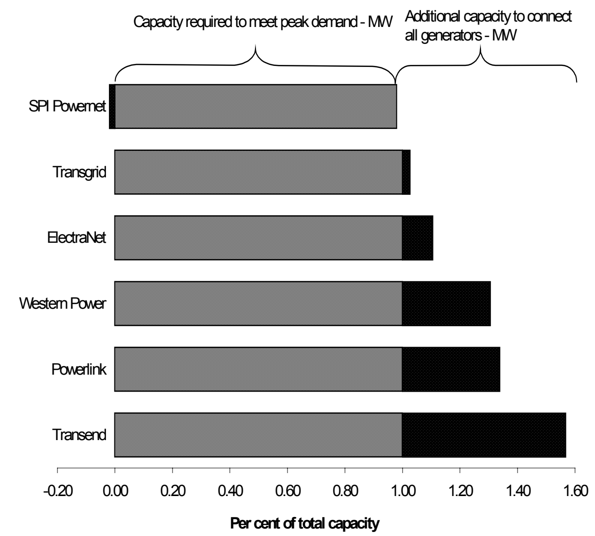
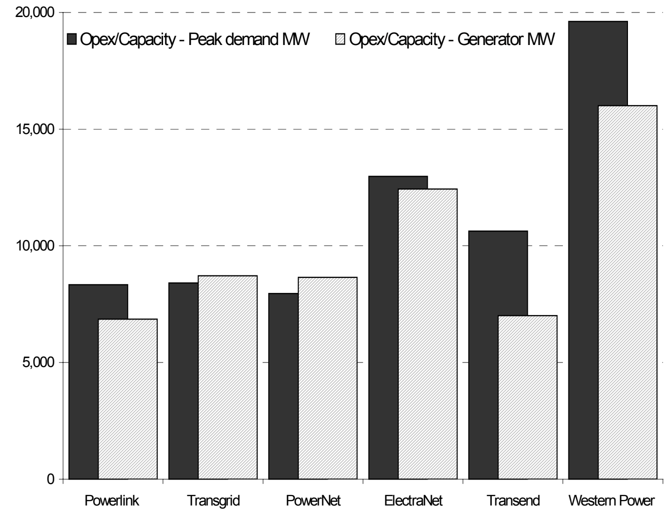
- *Connection points* at each end of the network; generators and bulk supply points; and
- *Reliability* ie availability and continuity of supply, represented in the model by minutes off supply.

It has been standard practice in transmission cost analyses to measure capacity investment as peak demand. This is not correct. Transmission capacity is more accurately measured by actual network investment, which is driven by the need to connect generators to the grid. This may not necessarily be the same as the capacity supplied to meet the peak demand of end users. Supply side capacity should not be less than that on the demand side since this would lead to a supply interruption at the peak. It can, however, be greater than the peak for a number of reasons.

One, differences between generator systems, for example, hydro where water availability dictates number and location of generators. Two, location of load, with widely dispersed load centres requiring local generation for grid support and loss minimisation, for example, Queensland. Finally, the investment cycle will also affect the ratio of supply side to demand side capacity. Changes in the ratio can provide important investment signals to regulators and other stakeholders. Converging levels of supply and demand side capacity suggests there is little excess capacity available to meet future demand growth and that additional transmission expenditure will be required in the near future.

The ratio of supply side to demand side capacity depicted in Figure 3 reveals quite substantial differences between the networks. Transend, the only Australian network to connect an almost entirely hydro-based system, faces a substantially greater investment requirement than the thermal based networks. Typically with below average capacity factors, depending on water availability, hydro-based systems can be required to provide almost double the generator, and hence network, capacity to meet peak demand. To meet a peak demand of 1630 MW, Transend connects 2500 MW of generator capacity (53 per cent above peak demand); in contrast, to meet Victoria's peak demand of around 8,000 MW SPI Powernet connects roughly an equivalent generator capacity.

This report uses supply side capacity as the measure of network output. By so doing, the report appropriately recognises the additional costs imposed on Transend's network by hydro-generation. Figure 4 below shows the impact of this measure on network costs, compared with the traditional peak demand approach.

Figure 3: Transmission capacity: supply and demand side[7]	*Figure 4: Opex: supply and demand side capacity
	

Finally, it is important to recognise that in contrast to most businesses, the level of output for franchised networks is largely outside the control of management. That is, the scale of production is an exogenous variable; management cannot limit its connections or supply less capacity than demanded to minimise operating costs or to raise prices. Likewise, business conditions, which affect the density of the load and the shape of the load curve must also impact on costs. Acceptable cost comparisons should therefore take certain business conditions to account:

- *Energy density*: network length required to deliver given quality of energy; and
- *Load factor*: consumption pattern of end-users.

[7] Supply side data is approximate only as accurate data is not publicly available

2.3 Costs of production – Distinguishing between costs and prices

The previous section used the notion of the production process to identify variables appropriate to cost model analysis. Building on this framework this section reviews the concept of efficient cost, distinguishing between the ***cost*** of supplying the network and the ***price*** charged for its use. Existing cost studies, in general, reveal a degree of misunderstanding about the meaning of these terms. Cost, price, average revenue, and even tariffs are often used interchangeably when in fact they represent different aspects of the relation between cost and output. Accordingly, for the purposes of this report these terms are defined as:

Cost: The cost-based nature of network pricing equates network cost to the sum of the building blocks as determined by regulators;

Price: As networks are entirely asset based businesses with little or no marginal cost for transporting an additional unit (MWh) of energy, unit prices depend on the number of units sold relative to the total cost of the network ("building blocks"). The greater the number of units sold for a given level of investment, the lower the unit price;

Average revenue: Total cost divided by total number of units sold. This may, or may not, be the same as unit price which is often calculated to reflect different categories of end-user, level of voltage offtake etc; and

Tariffs: charges to end-users, which may include mix of energy prices and demand charges.

This distinction is central to estimates of **cost** efficiency. The price measure, $/MWh, should not be used as a proxy for cost as it does not measure the efficiency of network operation only the relative use of the system by end-users. Subject to constraints imposed by the operating environment in the franchised territory, network businesses may exercise control over the efficiency of their expenditures but they cannot do so over its use.

The focus on efficient **costs** is fundamental to the regulatory pricing regimes adopted in Australia. The National Electricity Code, (clauses 6.2.2 – 6.2.5) states that transmission regulatory regimes must achieve outcomes, which are efficient and **cost** effective. In its Draft Decision for the South Australia Transmission Revenue Cap (2003-2008) the Commission noted it must have regard to the potential for efficiency gains in expected **costs.** Indeed, the revenue cap determined by the Commission is based directly on the **cost** of providing the network assets calculated as the return on, and of, capital necessary to provide the infrastructure and associated opex. In economic terms, notions of efficiency relate to these costs of production, not the prices charged for the use of the system, commonly referred to as TUOS (transmission use of system charge).

Figures 5 and 6 illustrate the difference between costs and prices. Measured as the cost of providing network capacity (regulated revenue $/supply side capacity MW) in Figure 5, Transend emerges as Australia's lowest cost network. However, when measured as $/MWh, (the price for the use of the system) Transend's relative performance deteriorates reflecting the lower energy throughput relative to its installed capacity (load factor).

Figure 5: Costs: Total cost/Supply side MW

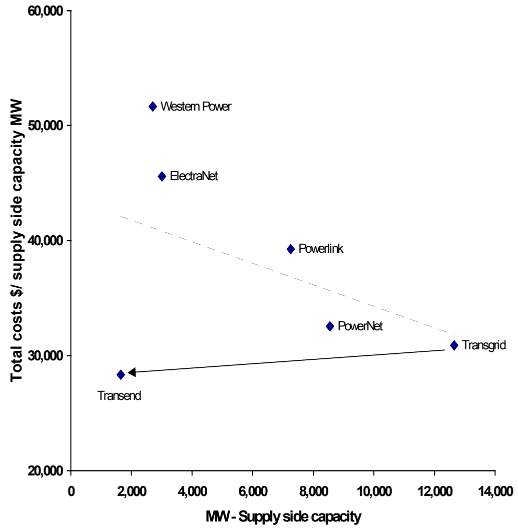
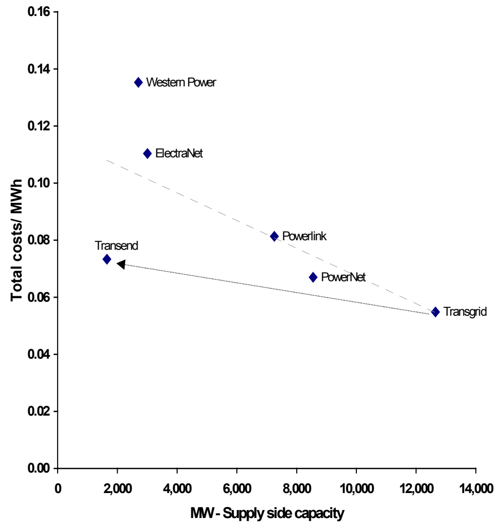


Figure 6: Prices: Total costs/energy transported MWh



2.4 Economies of scale

Economic theory holds that the cost of production will vary with the quantities of services provided (output scale) and certain business conditions. Given this well recognised link, the omission of considerations of scale in performance comparisons is surprising. Regulated pricing for electricity networks has been justified on the basis of their natural monopoly characteristics where decreasing costs provide such economies of scale that it is more efficient to have just one supplier for any given territory. That is, at the policy level it is accepted that larger scale networks will most likely enjoy lower costs. Irrespective, partial indicators using normalisers based on scale (MW, km, GWh) are consistently used to compare cost performance without any adjustment for scale affects.

Figure 7 and Table 1 attest to the presence of economies of scale. Typically, the larger scale networks benefit from a lower average asset requirement for each MW of capacity. The cost advantage is significant. Asset investment ranges from $190,000/MW for TransGrid up to around $300,000/MW for Western Power, a network only one-third the size of TransGrid. Accordingly, it would be inappropriate to compare the cost or asset performance of TransGrid with the smaller networks of Transend or Western Power without suitable adjustment for scale.

Figure 7: Scale and asset base

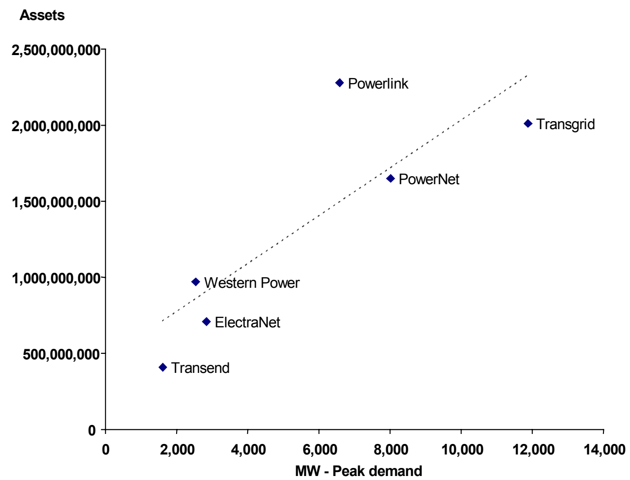


Table 1: Impact of scale on asset values

Capacity provided: Peak demand MW	Estimated total asset values	Asset investment per 1000 MW
2000	$815M	$407M
4000	$1,130M	$282M
6000	$1,446,M	$241M
8000	$1,761M	$220M
12000	$2,392M	$199M

3 Transmission network cost structures

This section examines network costs of Australian transmission businesses. It explores the relations between inputs and outputs and the impact of their scale and business conditions. The objective is to provide an overview of the major linkages that influence the cost outcomes of most interest to regulators.

Networks are capital-intensive businesses, with assets and capex accounting for approximately 70 per cent of total costs. Opex contributes the remainder. It is only to be expected that factors influencing the demand for, and use of, network assets will influence costs. Understanding the factors that drive asset investment is the key to successfully analysing transmission network cost structures. A comparative view: Australia's transmission networks.

To aid understanding of the relative cost performance of Australia's transmission networks this section presents a brief overview of their system characteristics as defined by scale and business conditions.

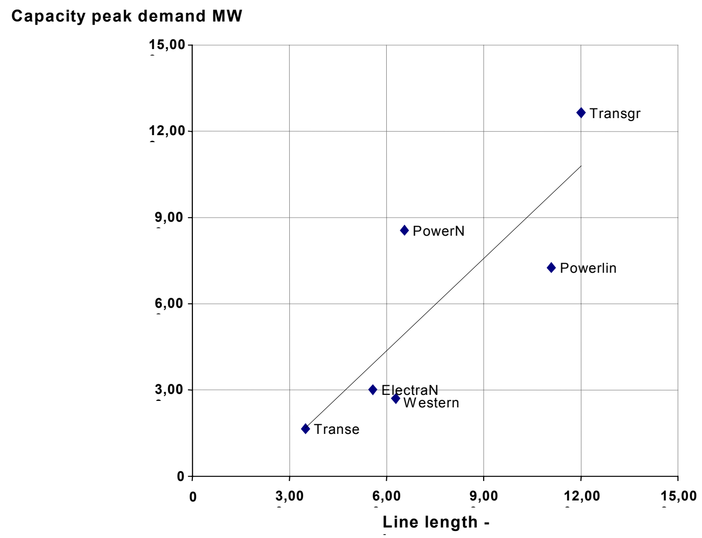
3.1.1 Scale

There is wide variation in the output scale of the Australian transmission networks.

Measured as length of the transmission connection (horizontal axis-km) there are three distinct groups; large TransGrid and Powerlink (10-12,000 km), mid-size SPI Powernet, ElectraNet and Western Power (5-6,000 km), and small Transend (3,400 km).

Measured as peak capacity provided (vertical axis-MW) there are also three different network scales: large: Transgrid (12,000 MW); mid-size Queensland and Victoria (6-8,000 MW); and the smaller networks of SA, Tasmania and Western Australia (2-3,000 MW) (Figure 8). Note however, that the position of the networks varies between the two measures.

Figure 8: capacity provided (peak demand MW) and network length (km)



3.1.2 Business conditions

Two conditions generally accepted as the most influential on network costs are energy density, measured as the level of capacity or energy transported per line length, and load factor, measured as the ratio of average demand to peak demand. As management has little control over these factors, incorporating adjustment for their influence is essential for valid performance comparisons. Higher levels of capacity provided or energy transported for a given network length lifts capacity utilisation of network assets. Likewise, higher load factors lift the average level of energy consumed relative to a given level of capacity provided. Rising capacity utilisation tends to lower average prices by spreading fixed costs across a greater number of output units. Put simply, it increases the productivity of the underlying investment. All else equal, networks with high energy density and load factors will enjoy a cost and/or rice benefit relative to other networks.

Figures 9 and 10 show energy density and load factor for each of the Australian networks. These ratios are measured by reference to peak capacity as this best reflects the demand imposed on the network by the network's "customers". Energy density for the Australian networks varies substantially. Transend has one of the lowest energy density networks, delivering only one third of the energy per network length compared to SPI Powernet.

However, Transend has the highest load factor of the Australian networks reflecting its large industrial base. Unfortunately, this apparent advantage is largely eliminated by the requirement to connect a further 53 per cent of capacity to ensure connection to the widely dispersed hydro generators. Taking total capacity into account, the load factor for Transend is reduced to 44 per cent. Given these business conditions Transend would be expected to face higher costs and therefore to have higher prices than, say, SPI Powernet or TransGrid.

Figure 9: Energy density (Peak demand MW/km)

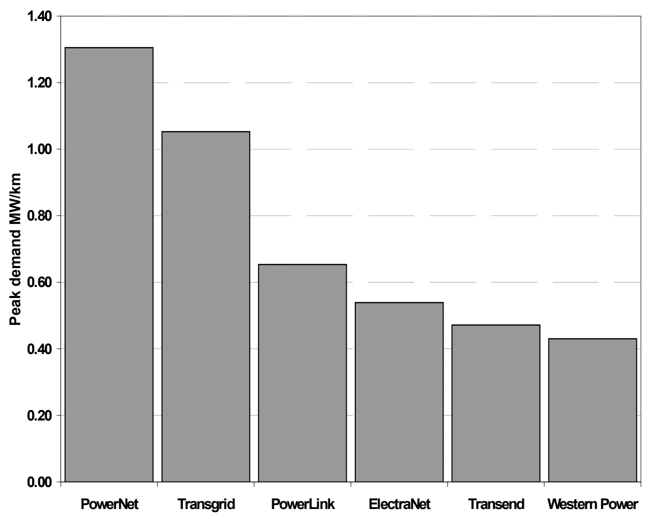
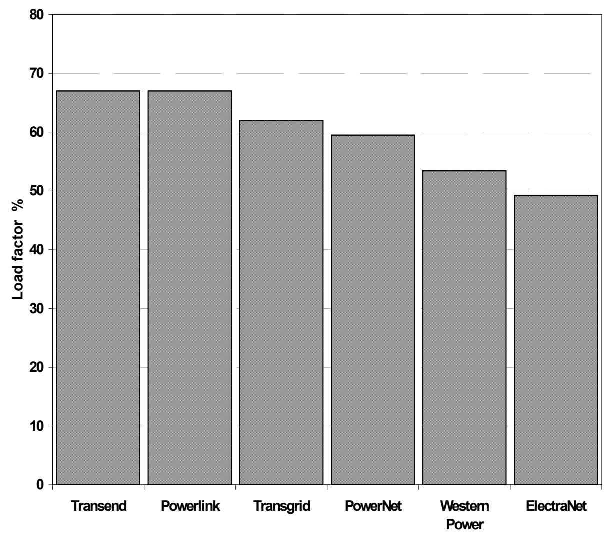


Figure 10: Load factor (Average to peak demand).



Claims by the networks regarding the nature of their cost drivers should not be dismissed lightly. Terms such as load factor and energy density are simply engineering terms describing certain ratios of the production process; the amount of network resources required to convey one unit of energy.

3.2 Transmission network cost structures

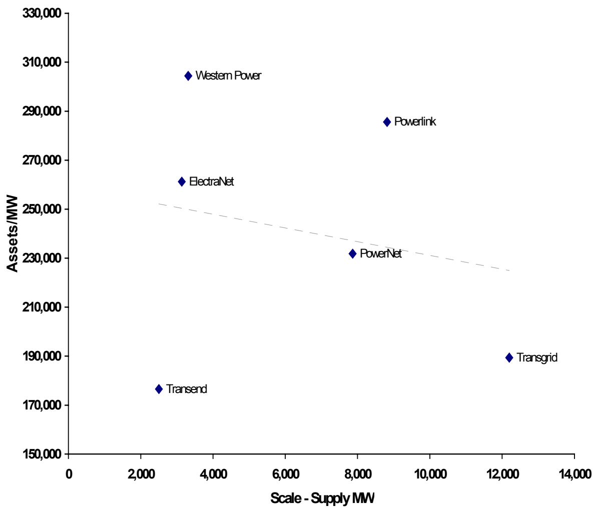
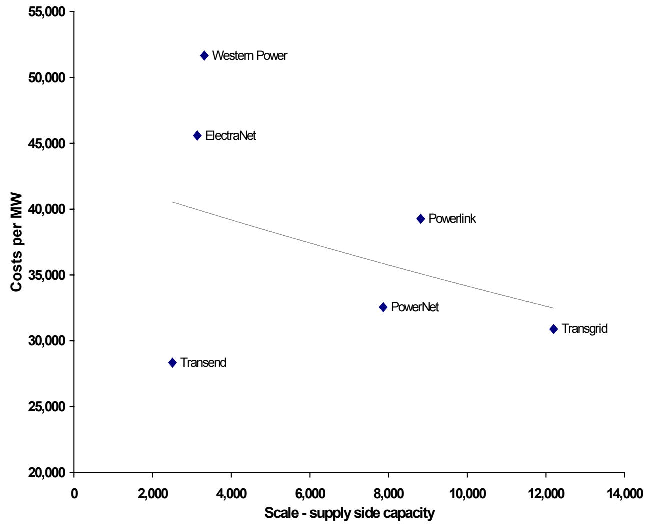
3.2.1 Network scale

Assets

If the assumption of natural monopoly status for networks holds we would expect to find significant economies of scale in the provision of fixed capital. That is, outputs will increase faster than the demand for asset inputs, with declining unit costs, at least for a large proportion of output.

Figure 7 in Section 2.4 demonstrated the decline in capital costs associated with increasing scale. Figures 11 and 12 extend this analysis by linking the assets/scale ratio to that of total costs/scale. Several factors emerge. One, larger networks have the advantage of lower capital costs per MW and hence can pass this benefit through in lower TUOS charges. Two, there is more variation in asset values than in total costs. The reasons for this are unclear. However, the magnitude of the variability suggests caution in the use of simple asset based ratios, for example, opex/assets, without a better understanding of the underlying causes. Given that opex relates to the **physical** asset base, not its financial value, this could be a more appropriate normaliser than the dollar value of the asset base.

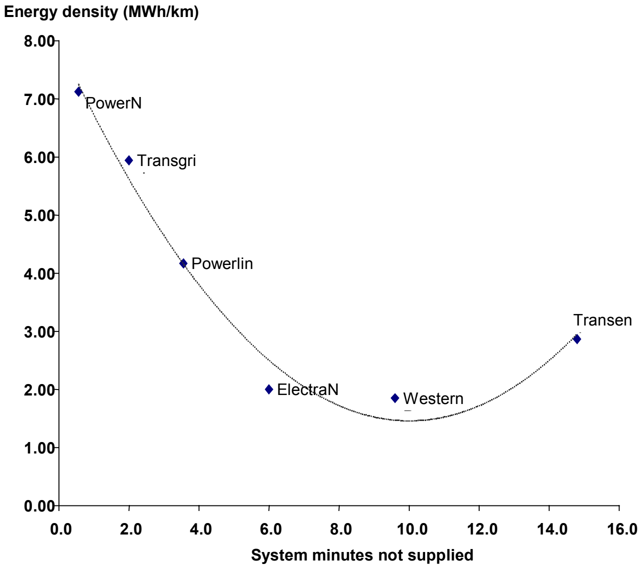
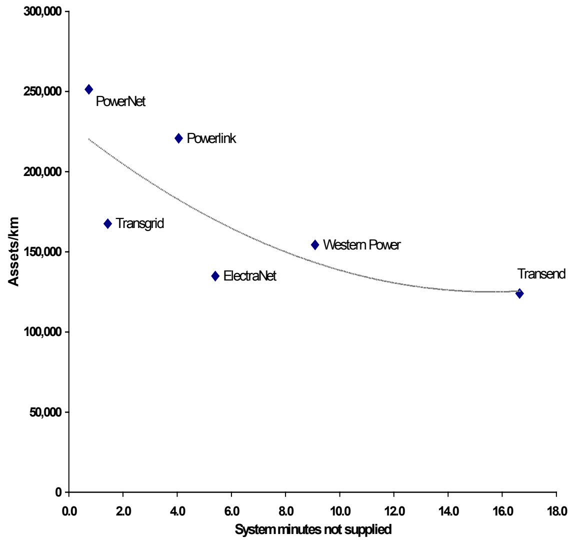
Finally, and of considerable significance for this current price reset, the position of Transend, Australia's smallest network, as the lowest cost network despite the cost disadvantage of its scale and business conditions, suggests that its building block revenues may need closer scrutiny to ensure their adequacy. It is likely that the traditional use of "price measures" (cost per MWh) as the basis for assessing efficient cost has obscured Transend's extremely low cost position.

Figure 11: Network assets and network scale	Figure 12: Network costs and network scale
	

While the cost effects of scale are evident in Figures 11 and 12 with costs generally declining as network scale increases, the charts also confirm that no single measure can adequately represent the bundle of outputs provided by transmission networks. Noticeable variation in the positions of the networks between Figures 11 and 12 reflects the influence on costs of factors other than scale, including supply voltage, age of network, or energy density.

Reliability

Reliability, defined in this analysis as system minutes not supplied, is related to the level of network investment. Investment in multiple circuits, higher voltage levels, and feeder length significantly influences reliability and quality of supply. Actual investment represents a trade-off between reliability and the commercial viability of the required investment. Accordingly, high voltage supply, and hence high reliability is generally associated with those networks where higher levels of energy density provide the level of returns necessary to justify the commensurate higher cost. Figure 13 depicts the link between energy density (another measure of scale) and reliability while Figure 14 confirms the link between asset investment and reliability.

Figure 13 Reliability and energy density	Figure 14 Reliability and investment ($/km)
	

These charts show that Transend's reliability level is significantly below that of the other TNSPs. There are numerous reasons for this result. For example, it is noted that "system minutes not supplied" is only one measure of service performance. In addition, Transend's significant industrial load means that a small number of "loss of supply" events can have a disproportionate impact on this service measure. Notwithstanding these observations, however, the level of performance achieved does raise issues as to whether an optimal mix of service performance and cost has been attained. In particular, Transend's very low cost performance might imply that these levels of expenditure are unsustainably low, especially if Transend is to aspire to the service levels required by modern industry.

Operating expenditures

Opex has been the major focus of efficiency comparisons for TNSPs. This is due as much to its nature as the only short run variable cost as to its importance in network cost structures. However, this narrow interpretation of costs leaves little room for legitimate tradeoffs between opex and capex. It also fails to allow for the different cost allocation policies that may occur in all commercial practices. Finally, it assumes that all opex allowances are comparable. A network with aging assets will require, pro rata, a greater opex allowance to maintain its assets compared with a new network with high quality assets.

More disturbingly, however, is the omission of considerations of scale in comparisons of opex performance. Though possibly not intuitive, the opportunity for scale effects should be signalled by the technically driven link between opex and the physical asset base. Figure 15 reveals a notable decline in opex (measured relative to capacity) as network scale increases. In contrast, opex (measured relative to network length) tends to rise with increasing network scale (Figure 16).

Figure: 15 Scale (Supply side MW) and Opex/Supply capacity (MW)

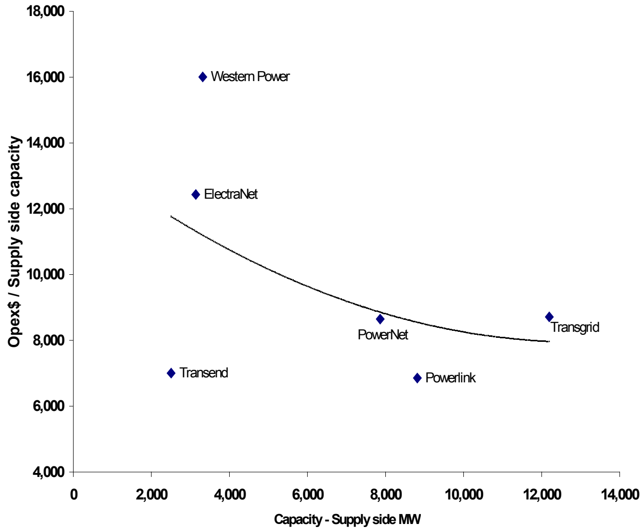
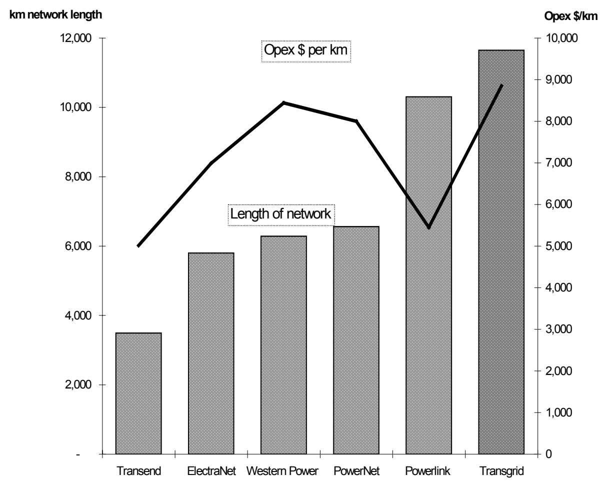


Figure: 15 Scale (network length km) and Opex/km



While Australia's largest networks also tend to be those with the greatest density and highest load factors, identification of the direct impact of scale and other conditions will remain somewhat unclear. Nevertheless, the range of opex levels should be sufficient to create uncertainty as to the wisdom of using these ratios for comparing relative operating efficiency. Once again, the position of

Transend well below the trend line (Figure 15) suggests that its starting point revenue base should be closely re-examined. Certainly, the cost position of Transend does not indicate a level of opex that is "too high" relative to its peers.

The ratio opex/assets has emerged as a preferred indicator for regulatory assessments of operating efficiency. We would caution against the use of this measure; it is influenced by both the level opex and of assets. A low ratio may simply reflect a high asset valuation rather than efficient operating performance. Alternatively, a high ratio may simply reflect the higher level of opex necessary to maintain an aging, but lower valued, network. To illustrate. Transend has Australia's oldest network, which could explain the low value of its asset base although a much higher level of opex than the current allowance would be expected to maintain the network in good operating condition. Despite its "outperformance" as the least cost network on both the assets/MW and opex/MW performance indicators, Transend's opex/asset ratio rates high at 3.9, compared to only 2.6 for Powerlink. Powerlink, with Australia's youngest network has a relatively higher asset base and a commensurately lower requirement for opex. This conflict between demonstrated cost performance and the opex/assets ratio suggests the ratio hides more than it reveals.

Capital expenditures

There are two classes of capex: refurbishment and replacement of the existing asset base; and augmentation to meet load growth and generator developments. Factors driving capex investment are therefore more numerous and complex than those driving the original asset investment. Each capex stream will be influenced by a different suite of factors: asset age and previous maintenance practices will influence the first while load growth and market related interconnector developments will drive the latter.

The effects of scale are pervasive. Figure 17 depicting the link between scale (MW) and capex/MW provides further confirmation of the cost advantage enjoyed by the larger networks. Capex for Transend is commensurate with its scale. Note, that SPI Powernet is not directly comparable with the other networks since it does not have responsibility for network augmentation. The link between network length and capex/MW is less clear, (Figure 18) although some indication that smaller networks face generally higher average costs for investment is evident. Possibly more rapid expansion of the new systems in Western Australian and Queensland would be a contributing factor to their relatively higher levels of capex.

Figure 17 Scale (peak demand MW) and capex/MW

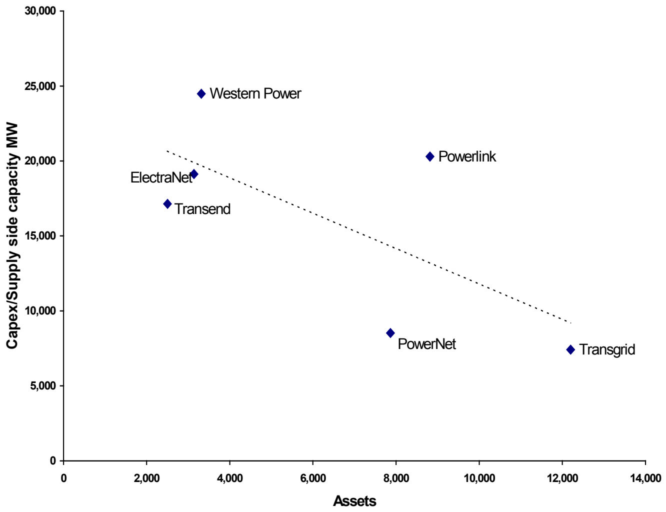
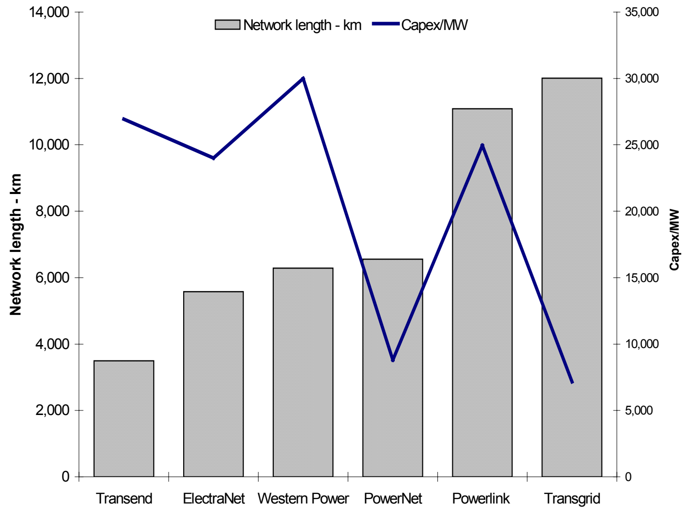


Figure 18 Scale (km) and capex/MW



Age of grid There has been considerable debate about the relative age of transmission networks. Lack of suitable data on network age has precluded quantitative analysis, although this does not appear to have deterred qualitative assumptions. One possible alternative is to use the age of base load generation as a proxy. As network augmentation tends to proceed in step with generator construction, this approach should at least establish boundaries for the debate. The weighted average age of base load generation for Australia is detailed in Table 2.

Table 2: Weighted age of base load generation

Tasmania	1972	Victoria	1982
South Australia	1980	Western Australia	1982
New South Wales	1980	Queensland	1986

It is recognised that transmission grids may pre-date the existing in-use generators and, accordingly, that this methodology could underestimate the age of the transmission network. However, the purpose of this calculation is to present some ranking of network age rather than an estimate of absolute age. Tasmania, with a long established hydro-base and the slowest rate of load growth, has a network that arguably is the oldest in Australia.

3.2.2 Network business conditions

Energy density and assets

Energy density has two, but contrasting, impacts on asset investment. In the first, rising density appears to reduce the level of average investment required for each MW of capacity provided ($/MW) (Figure 19). For example, fewer but larger substations and transformers can be accommodated in the larger networks. Substantial cost economies are available with increasing transformer size. In contrast, rising energy density lifts the level of assets required per line length (Figure 20).

Figure 19 Energy density (MW/km) and assets/MW

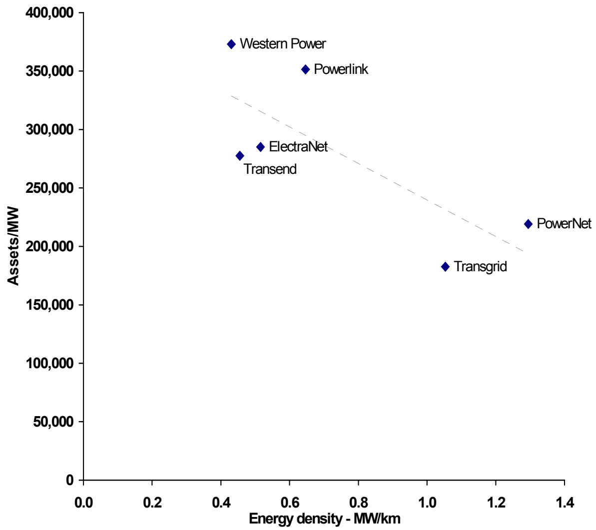
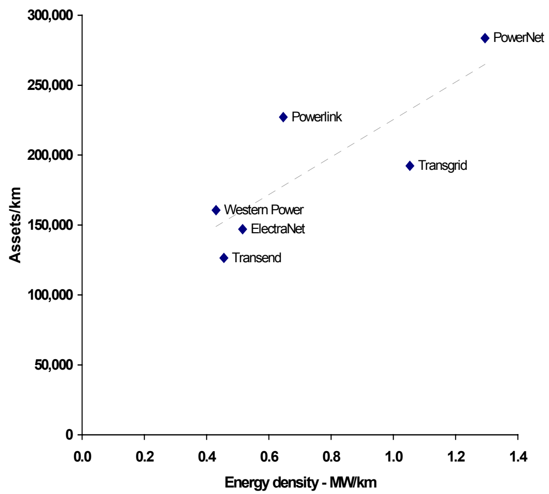


Figure 20 Energy density (MW/km) and assets per km



More complex systems and the greater reliability required for high density loads are contributing factors to the higher line costs. Transend, with one of the lowest levels of (demand side) energy density, is disadvantaged by higher average capacity costs (Figure 19) but benefits from lower average line costs (Figure 20). Its cost outcome, however, will be largely influenced by the total length of network required to provide a given unit of capacity: as an illustration, consider that for each MW of peak demand capacity provided Transend must invest in 2.3 kilometres of network, compared with only 0.77 kilometres for SPI Powernet.

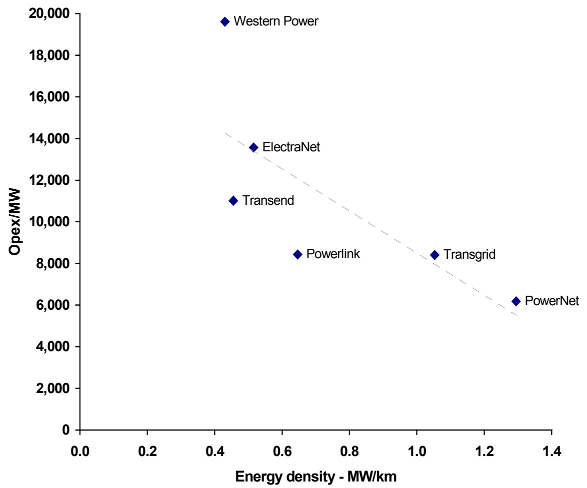
These contrasting outcomes highlight the problems confronting regulators, and the industry, in selecting appropriate indicators for cost comparisons. Choose one measure, and Transend appears low cost, choose an alternative and its cost comparison is less favourable.

Energy density and operating expenditure

The close link between opex and the asset base is well demonstrated by examining the impact of energy density on operating costs. Figure 21, indicates that rising energy density tends to lower the average costs of opex expenditures. Some insight into this trend can be gained form the data in Table 3, which shows the length of network that each network maintains to provide 1 MW of capacity.

Claims by networks that factors such as energy density can affect their relative opex position have not been accepted in regulatory pricing determinations. Instead, it has been argued that opex is driven only by the asset base, justifying use of the misleading opex/asset ratio for performance comparisons. However, the link between opex and density *is* the asset base. A network required to maintain 2.2 km of network for each MW of peak demand (a typical normaliser in cost comparisons), all else equal, can be expected to have a higher opex/MW ratio than a network maintaining only 0.8 km to provide the same output.

Figure 21: Opex/capacity (MW) and energy density (MW/km)	**Table 3: Network length required to provide 1 MW capacity**



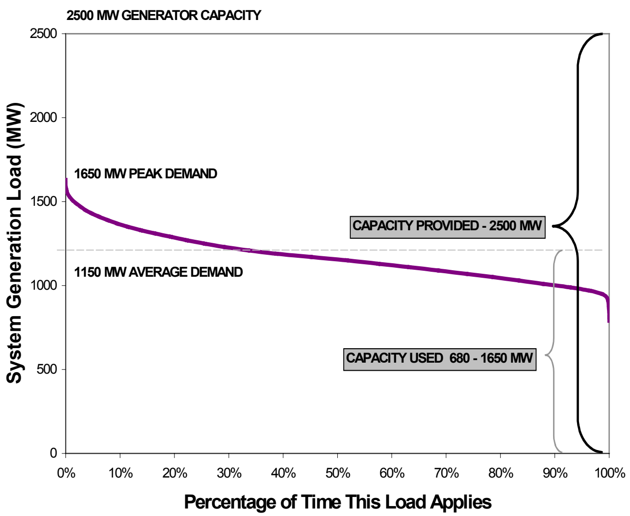
Western Power	2.48 km
Transend	2.20 km
ElectraNet	1.97 km
Powerlink	1.57 km
TransGrid	1.01 km
SPI PowerNet	0.82 km

Load factor and assets

Load factor, typically measured as average demand to peak demand, influences asset requirements by setting the total capacity investment necessary to meet average demand. A low load factor will require more assets to be invested for any given level of average demand. Recall, however, that transmission networks are required not only to supply capacity to meet peak demand but also to ensure sufficient capacity to connect the generators. For some networks there may be little difference between the two capacity measures, but for Transend the additional supply side capacity required represents a substantial additional investment. While Transend has a demand side load factor of 72 per cent, among Australia's highest, this drops to 46 per cent when the average load is compared to the total level of capacity that it actually provides.

That is, for an average demand of 1150 MW Transend provides 2500 MW of network capacity, representing a substantial cost burden. As the regulated revenue requirement (cost) relates to the entire network capacity of 2500 MW, while TUOS charges only apply to the average use of the network, low load factors typically lead to relatively higher prices. Figure 21 depicting the load duration curve for Transend measured against total network capacity provided, illustrates the sizable imbalance between capacity required and capacity used.

Figure 22: Transend load duration curve



These cost affects are exacerbated by peakiness of demand. For example, the top 130 MW is only used one per cent of the time.

Despite its significance in determining price outcomes, load factor is not often accorded the attention it merits. The possible gains from more efficient use of networks by raising load factors and hence capacity utilisation are substantial. For the average Australian network, a reduction of 20 per cent in opex would cut network prices by around 6 per cent but lifting load factor by 20 per cent, would reduce the average price by around 17 per cent. Shifting load factor is not achieved lightly, but the benefits to end-users from more balanced load growth suggest that closer attention to this cost driver could provide large consumer dividends.

Load factor and operating expenditure

The link between opex and load factor reflects that between assets and load factor. All capacity installed, not just that provided to meet peak demand, must be maintained in good working condition. In terms of energy transported, Table 4 shows that low load factor networks such as Transend and Western Power are required to maintain up to 40 per cent more capacity assets for each GWh of energy transported.

Figure 23: Opex/capacity (MW) and load factor

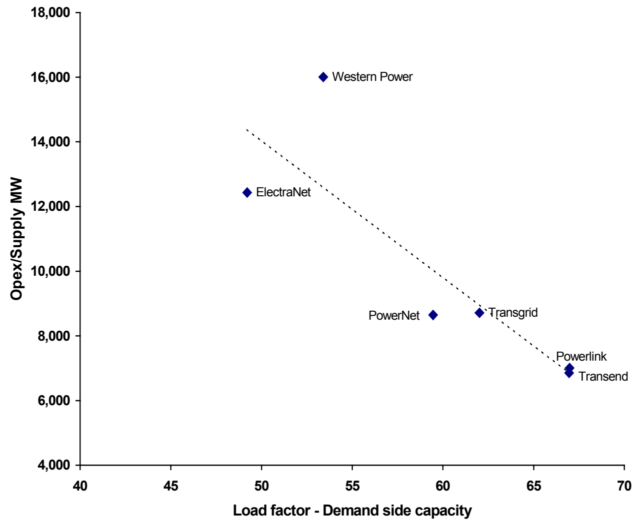


Table 4: Network capacity required to transport 1 GWh

Transend	0.26 MW
Western Power	0.26 MW
ElectraNet	0.25 MW
Powerlink	0.21 MW
Transgrid	0.18 MW
SPI PowerNet	0.18 MW

3.2.3 Summarising

Though the sample is small, certain links emerge strongly. Relative levels of assets and opex are influenced strongly by scale and business conditions. The large networks, SPI PowerNet and Transgrid, benefit from scale of operations and advantageous business conditions. These factors describe the business environment in which they operate, rather than the outcome of a management-led initiative. Therefore, the performance of these companies should not be used as a yardstick for measuring the performance of other networks without adequate adjustment for these factors.

In general, average costs rise with increasing distance (reflecting the greater complexity of the network in the larger systems). However, average costs decline with rising capacity providing direct evidence of the benefits of scale. To achieve meaningful efficiency comparisons by normalising costs against these outputs, length (km) or capacity (MW) is simply not possible. The network with the lowest $/MW is likely to also have the highest $/km, for example, SPI PowerNet. This cannot provide any useful information on its relative efficiency. Any use of the **price** measure, $/MWh, as a measure of **cost** performance adds further to this confusion.

4 Conclusion

The wide-ranging scale and business conditions shaping Australia's transmission networks have resulted in a group of businesses that from one perspective appear distinctly different from each other. But from the perspective of a common cost structure they represent no more than fluctuations around well defined trends. This is important to regulators seeking to determine relative levels of efficient costs.

It would appear that the lack of a formally developed econometric cost model for assessing relative efficiency has been a handicap for regulators. It has also been a burden for those networks that, on a superficial level, appear to be relatively poor performers. The use of simple partial indicators, without adjustment for key cost drivers, could distort regulatory decision making – unfairly favouring or disadvantaging some companies. By drawing on existing economic principles, this report has demonstrated that it is possible to develop a basic cost structure framework for transmission networks. In time, this will be extended by more in depth analysis of the linkages between the engineering and economic parameters.

Transend, one of Australia's smaller networks emerges as a relatively low cost system, often with costs that appear below those justified by its scale and operating environment. The underlying reasons for this are unclear – although the relatively poor service performance is potentially one consequence of such low operating costs. It is recommended that close attention be directed to the initial building blocks to ensure their adequacy for a network of this configuration. We believe that going forward from the existing base could provide Transend with insufficient revenues over the medium term to maintain its network.

Appendix A

Data used in this analysis

The quality of the data is a critical element of any quantitative analysis. To ensure comparability appropriate to regulatory benchmarking, where available, the data used in this analysis has been taken from revenue cap decisions by the Commission. For Transend and Western Power data has been taken from the jurisdictional regulatory reviews.

Building block data is for year ending June 2003. Network parameters have been taken from NEMMCO Statement of Opportunities and jurisdictional Statements of Opportunities (source ESAA Electricity Australia, 2002). However, network length is data for 2001. It would be preferable to use 2003 data but no publicly available source of updated network length could be located.

Opex data has been standardised as much as possible by excluding grid support.

Every care has been taken to ensure that the data are a true and faithful account of those data published by the regulators and other authorities. There will be minor variations since myriad adjustments to regulatory data can introduce complexity, and indeed, confusion. For example, smoothing, however desirable, can shift revenue from year to year.

It would assist analysis of network cost structures if a complete table of annual data including network parameters and agreed building block revenue allowances over the price re-set were published with each pricing Decision.

Appendix B

Data sources

Data is for the year ending June 2003. However, network length is generally for the year ending June 2002.

Financial data has been sourced from most recent regulatory pricing decisions. For Transgrid, Powerlink, SPI PowerNet and ElectraNet the regulator is the Australian Competition and Consumer Commission. Regulatory reports by state jurisdictions have been used for those networks that have not yet been the subject of a pricing determination by the Commission.

Network parameters Where available, data are sourced from regulatory pricing decisions. Where data are unavailable the source is ESAA Electricity Australia, various years. Peak demand, MW, is measured as coincident peak demand.

Reliability data: ESAA Electricity Australia, various years. A five-year average has been used to smooth the volatility of this series.

Data that was not available from these publicly available sources was sourced through personal communication with industry participants.

APPENDIX 3
Issues relating to future asset valuations

TRANSEND

APPENDIX 3 – ISSUES RELATING TO FUTURE ASSET VALUATIONS

Transend is concerned that future asset valuations should provide the right incentives for transmission investment. At the core of such arrangements is the process for recognising future capital additions in the asset base. Presently, the NEC and TEC provide two alternative mechanisms by which new investment can be reflected in future revenue determinations.

The first method 'rolls forward' prudent investment less disposals and depreciation. This is precisely the mechanism adopted in Section 4.3.3 to update the Minister's valuation as at 30 June 2001 to its corresponding value as at 1 January 2004.

This method ensures that the TNSP is remunerated for prudent investment by rolling capital additions into the asset base. Under the TEC and NEC, 'prudency' reviews can occur both prior and subsequent to the investment taking place. The prior review is through the 'market benefits test', whilst the subsequent review takes place during the revenue determination process.

The second method applies the DORC valuation methodology periodically to assess the value of the sunk assets plus any subsequent capital additions. This approach ensures that the asset valuation does not exceed the amount that would be paid by a 'notional' new entrant. Essentially, it is an alternative method for ensuring that only prudent investments are added to the sunk asset base. The Commission has commented[1] that this method will be applied where there has been:

- a major advance in technology such as the development of new materials
- mergers or change of ownership of transmission assets
- major expansions or contractions of the network such as may arise due to the development of a by-pass option
- evidence that the TNSP is unable or unwilling to recover the full cost of service calculated for some sub-system
- a request by the TNSP facing by-pass for a significant economic write-down of part of its asset base.

Transend supports the use of the DORC methodology. However, the existence of two alternative methods for remunerating new investment raises the possibility that the same network assets can be valued differently by each method. In such circumstances, the question arises as to which of the two valuations is *correct*.

Transend's view is that the method for valuing network assets should ensure that:

- the TNSP is remunerated for prudent investments
- the TNSP is not exposed to risk which it is not best able to manage.

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1 ACCC, draft *Statement of Regulatory Principles*, May 1999, p. 49

In particular, Transend supports an approach that exposes TNSPs to the risk of asset stranding where this exposure can encourage more efficient investment decisions. However, it is highly questionable whether exposing TNSPs to the risk of technological change or movements in unit capital prices will provide such an investment discipline.

TNSPs typically cannot manage the timing and scope of investment decisions to take advantage of technological developments or unit capital price movements. It would be highly impractical to accept long-term deferral of transmission investments in order to exploit future technological developments or lower unit costs. However, the DORC methodology effectively penalises TNSPs where such deferrals have not taken place.

Transend fully accepts financial exposure where real competitive alternatives to the electricity transmission network (such as reticulated gas or embedded generation) exist. This financial exposure reinforces the need for Transend to be aware of these competitive alternatives when formulating its investment plans. In our view, the DORC methodology should be limited to imposing these risks on TNSPs.

Unfortunately, our experience of the DORC methodology is that it exposes TNSPs to a much broader set of risks. Transend's strong view is that these risks deter investment rather than encourage better investment decision-making. As such, the DORC methodology imposes costs on TNSPs (and on users of the transmission system) without any compensating benefit.

Transend's view is that the Commission should give careful consideration as to how the risks of changing technology and unit capital prices are taken into account in future asset revaluations. Unless TNSPs are remunerated for taking this risk, future investment in transmission networks is likely to be detrimentally affected by imposing this risk on TNSPs.

Transend is also concerned that future DORC valuations may be conducted on a 'greenfield' basis. Under this methodology, replacement costs are assessed as if the transmission system could be replicated en masse. In reality, the transmission system has been constructed through a piecemeal process of incremental developments and additions. The 'greenfield' approach vastly understates the actual costs incurred in building a growing network over a number of years, and thereby fails to recognise investment costs faced by TNSPs.

Transend's view is that a DORC valuation approach which results in prudent investment being stranded would be inconsistent with the requirements of the NEC. In particular, clause 6.2.2 states that the regulatory regime should foster efficient investment in the transmission system. Transend's contention is that stranding prudent investment will not foster an environment where efficient investment will occur. The challenge is therefore to ensure that the application of DORC does not lead to this outcome.

ElectraNet raised similar concerns regarding optimisation risk, during the Commission's recent revenue determination process. Under ElectraNet's proposed approach, refurbishment expenditure would be treated as operating expenditure, rather than capital expenditure. This approach would ensure that refurbishment expenditure is not optimised-out by subsequent DORC valuations.

In its decision[2], the Commission acknowledged the legitimacy of ElectraNet's concern, but rejected its proposed solution. Instead, the Commission concluded that refurbishment should be identified as a separate line-item of capital expenditure and:

- quarantined against optimisation for 10 years
- depreciated over 10 years, thereby recognising that its value may be extinguished well before the life of the (original) asset.

In the light of the Commission's decision on this issue, Transend has refined its capitalisation policy. In particular, Transend has separately identified refurbishment capital expenditure from 1 July 2003 onwards, and applied a class life of 15 years. In Transend's view, a class life of 15 years reasonably reflects the economic life of refurbishment expenditure.

Transend's review of its capitalisation policy highlighted that some activities should be re-classified as O&M expenditure rather than capital expenditure. Such activities include power transformer mid-life overhauls, replacement of transformer bushings, and corrosion repairs on substation steel structures. The expenditure forecasts presented in this submission reflect the company's revised capitalisation policy.

While Transend believes that the Commission's approach to refurbishment expenditure is a step in the right direction, it is unclear whether it can resolve all the optimisation issues discussed in this Appendix. Transend would therefore welcome further discussion with the Commission to clarify its approach to the issues raised.

Pending these further discussions, this submission is presented on the basis that future prudent network investment will be remunerated through the Commission's asset valuation methodology. In particular, it is assumed that the Commission will ensure that the DORC valuation methodology does not penalise TNSPs for making prudent incremental additions to its capital base. Transend would seek retrospective compensation, possibly through additional depreciation charges, if prudent network investments were subsequently stranded by the Commission's approach to asset valuation.

[2] ACCC, *Decision: South Australian Transmission Network Revenue Cap*, 11 December 2002, p. 65

APPENDIX 4
Transend's performance incentive scheme

APPENDIX 4 – TRANSEND'S PERFORMANCE INCENTIVE SCHEME

This appendix relates to Chapter 5 of the main submission, and also Appendix 1, Transend's proposed revenue control. It should be noted that the performance targets relate to each financial year. The table below shows:

- the *service indicator* and the associated *measure*
- the *maximum revenue at risk*, which is the amount of revenue at risk for each service indicator
- the *maximum penalty performance*, which is the performance level at which the maximum penalty is paid by Transend
- the *penalty trigger*, which is the performance level at which penalties will start being paid by Transend
- the *bonus trigger*, which is the performance level at which bonuses will start being received by Transend
- the *maximum bonus performance* , which is the performance level at which the maximum bonus is paid to Transend.

Table A1: Proposed service indicators and targets

Service Indicator	Measure	Maximum revenue at risk	Maximum Penalty performance	Penalty Trigger	Bonus Trigger	Maximum Bonus performance
S1 - Transmission circuit availability	Percentage availability	0.25%	98.8%	<99.0%	>99.1%	99.3%
S2 - Transformer circuit availability	Percentage availability	0.15%	98.8%	<99.0%	>99.1%	99.5%
S3 - Loss of Supply Event Frequency Index (a)	Number of events where loss of supply exceeds 0.1 system minutes	0.2%	20 events	>16 events	<14 events	10 events
S4 - Loss of Supply Event Frequency Index (b)	Number of events where loss of supply exceeds 2.0 system minutes	0.4%	5 events	>3 events	<2 events	0 events

These proposed financial year service indicators and targets are shown in diagrammatic form below.

It should be noted that the choice of targets reflects Transend's past performance. The overall objective is for the performance incentive scheme to be revenue neutral. Most of the graphs are symmetrical in that performance above and below the trigger levels are treated on the same basis. However, with respect to transformer circuit availability, performance which is better than the bonus trigger is probably valued less highly by customers than performance which is worse than the penalty trigger. In addition, Transend believes it can meet the challenge of a stretch target for transformer circuit availability.

Figure A1: S1 - Transmission circuit availability

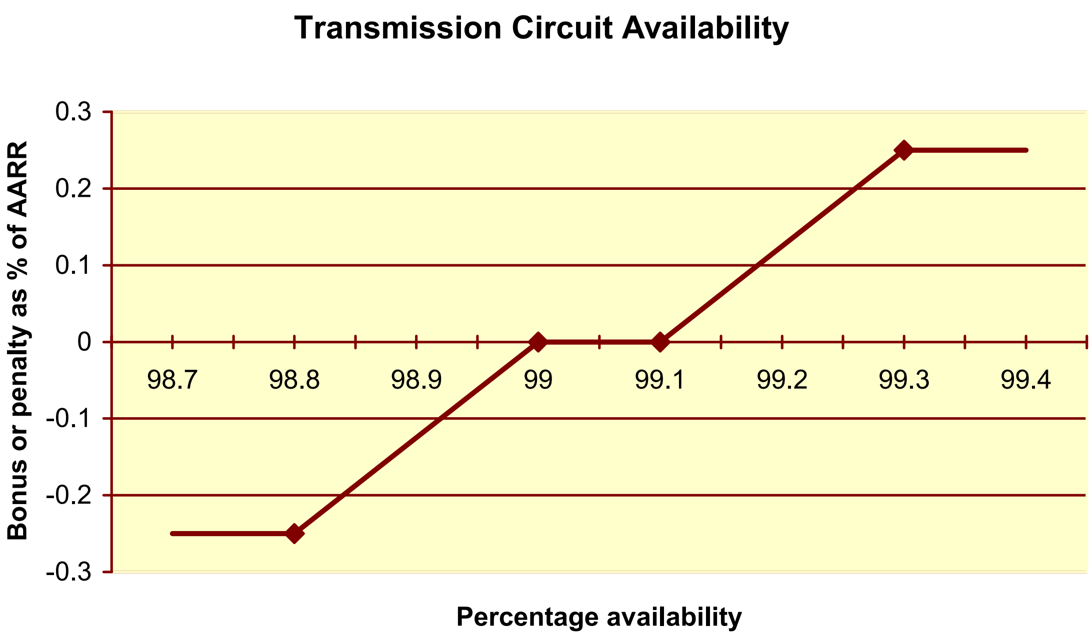


Figure A2: S2 - Transformer circuit availability

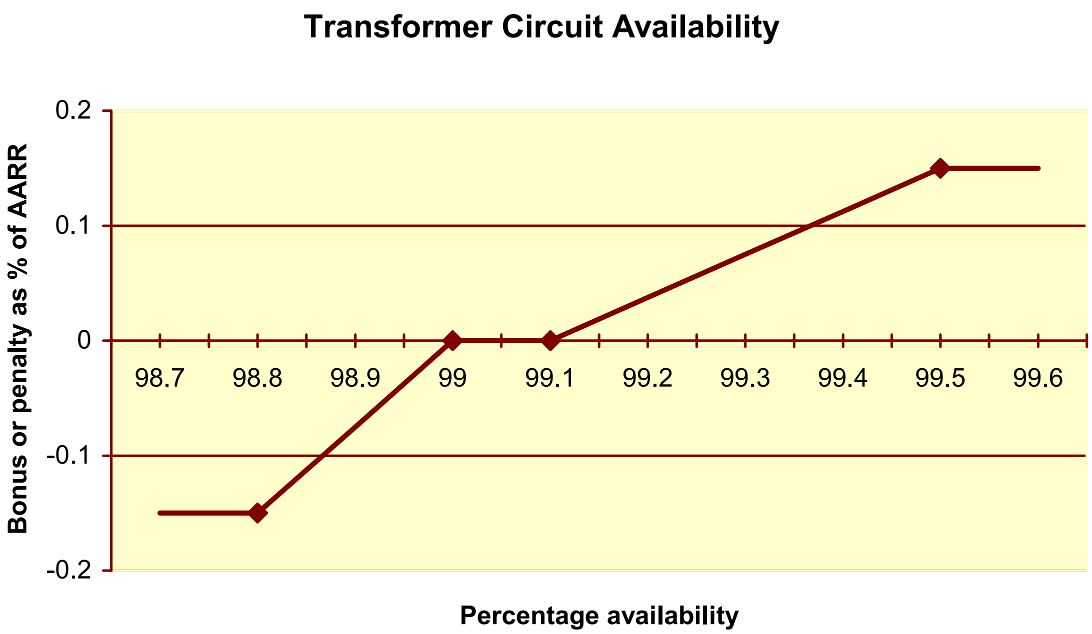


Figure A3: S3 - Loss of Supply Event Frequency Index (a) for loss of supply above 0.1 system minute

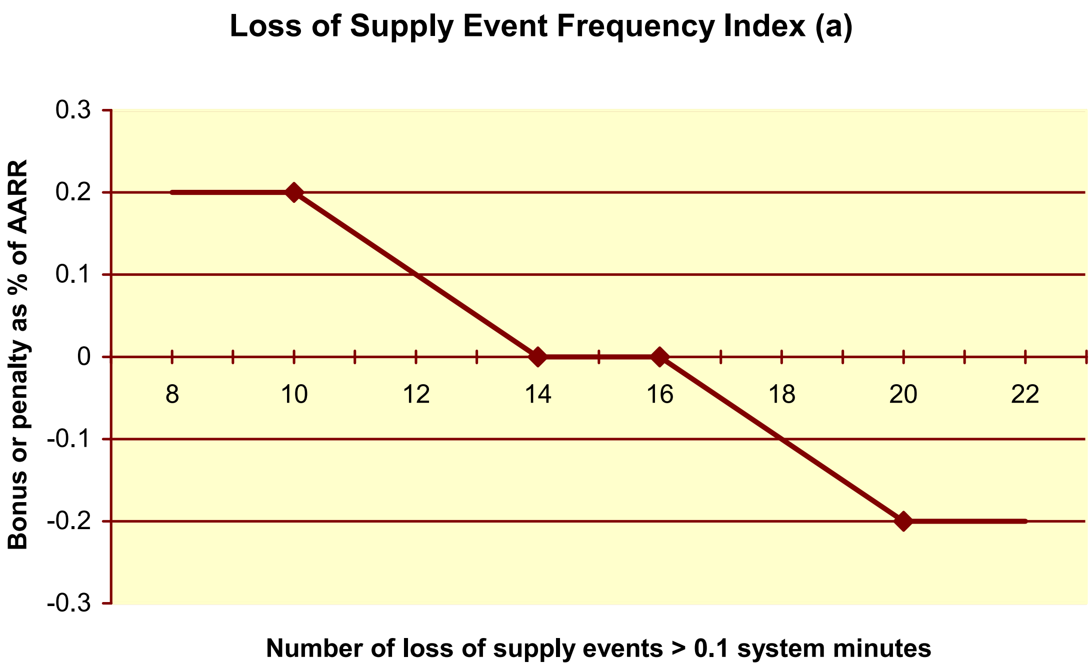
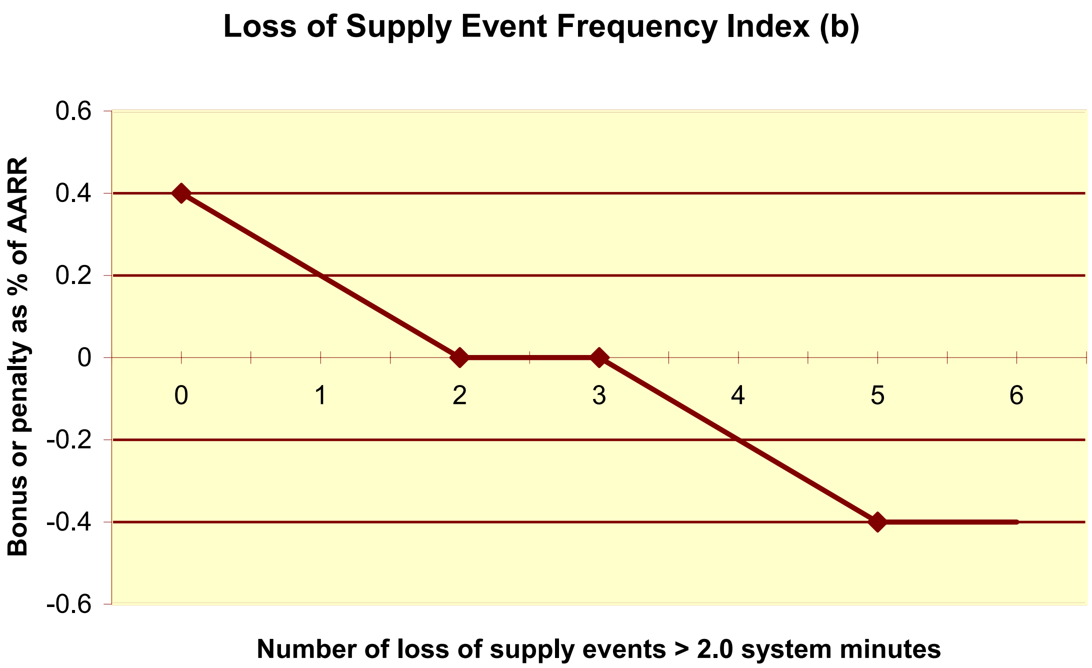


Figure A4: S4 - Loss of Supply Event Frequency Index (b) for loss of supply above 2 system minutes



These graphs can be expressed as a series of straight-line equations. Appendix 1 provides a detailed explanation of how these equations are applied to Transend's revenue control formulae. The definition of each service measure is also provided below. It should be noted that these formulae relate to each financial year of the revenue period.

Table A2: Definition of each service measure

S_1 Transmission circuit availability (%)	**Where:**
S_1 = -0.0025	Actual availability ≤ 98.8
S_1 = 1.25 * actual availability – 1.23750	98.8 < Actual availability < 99.0
S_1 = 0.0000	99.0 ≤ Actual availability ≤ 99.1
S_1 = 1.25 * actual availability – 1.23875	99.1 < Actual availability <99.3
S_1 = 0.0025	Actual availability ≥ 99.3

S_2 Transformer circuit availability (%)	**Where:**
S_2 = -0.0015	Actual availability ≤ 98.8
S_2 = 0.75 * actual availability – 0.74250	98.8 < Actual availability < 99.0
S_2 = 0.0000	99.0 ≤ Actual availability ≤ 99.1
S_2 = 0.375 * actual availability – 0.371625	99.1 < Actual availability < 99.5
S_2 = 0.0015	Actual availability ≥ 99.5

S_3 Loss of Supply Event Frequency Index (a) for loss of supply events above 0.1 system minute	**Where**:
S_3 = -0.002	Loss of supply events ≥ 20
S_3 = - 0.0005 * loss of supply events + 0.008	16 < Loss of supply events < 20
S_3 = 0.0000	14 ≤ Loss of supply events ≤ 16
S_3 = - 0.0005 * loss of supply events + 0.007	10 < Loss of supply events < 14
S_3 = 0.002	Loss of supply events ≤ 10

S_4 Loss of Supply Event Frequency Index (b) for loss of supply events above 2 system minutes	**Where**:
S_3 = -0.004	Loss of supply events ≥ 5
S_3 = - 0.002 * loss of supply events + 0.006	3 < Loss of supply events < 5
S_3 = 0.0000	2 ≤ Loss of supply events ≤ 3
S_3 = - 0.002 * loss of supply events + 0.004	0 ≤ Loss of supply events < 2

Table A3: Proposed definition for performance measures S_1 and S_2

Measure	Circuit Availability
Sub-measures	❖ Transmission Circuit Availability ❖ Transformer Circuit Availability
Unit of Measure	Actual plant hours available as a percentage (%) of total plant hours possible
Source of Data	❖ TNSP outage management system ❖ TNSP faults / outage database ❖ Operation Control System
Definition / Formula	Formula: $\frac{\text{Number of hours per annum plant circuits are available}}{\text{Total possible number of plant service hours}} \times 100$ Definition: The plant circuit hours available for transmission plant (meaning the plant is either in service or readily capable of being placed into service) divided by the total possible plant circuit hours.
Exclusions	Exclude: ❖ transmission assets that do not provide a prescribed service ❖ any outages shown to be caused by a fault or other event on other code participant's equipment eg. intertrip signal, generator outage, customer installations and market network service providers ❖ outages due to opening of a circuit for system security or power transfer purposes ❖ outages due to operation of load shedding scheme, contracted load reduction or generation short falls ❖ outages due to customers exceeding their contracted demand or load on equipment exceeding the rating prescribed by Transend ❖ outages due to mal-operation of the System Protection Scheme ❖ outages to install wholesale energy market metering ❖ force majeure events.
Inclusions	Include: ❖ transmission circuits comprise all transmission lines, including overhead lines and underground cables, which are owned by Transend (note that Transend owns transmission circuits at 220 kV, 110 kV and 88 kV) ❖ transformer circuits includes all network and supply transformers that are owned by Transend (note that majority of Transend's transformers are supply transformers that supply at distribution voltages of 44, 33, 22, 11 and 6.6 kV) ❖ circuit 'unavailability' to include outages from all causes including planned, emergency and fault events.

Table A4: Proposed Definition for Performance Measures S_3 and S_4

Measure	Loss of Supply Event Frequency Index
Unit of Measure	Number of loss of supply events per annum
Source of Data	TNSP faults / outage database
Definition / Formula	Number of events above 0.1 system minute Number of events above 2.0 system minutes Formula for system minutes: $System\ Minutes = \left(\frac{Unserved\ Energy\ (MWh)}{System\ Maximum\ Demand\ (MW)}\right) x \left(\frac{60}{1}\right)$
Exclusions	Exclude *Unserved Energy* caused, directly or indirectly, by: ❖ transmission assets that do not provide a prescribed service ❖ other code participants eg. intertrip signal, generator outage, customer installations and market network service providers ❖ energy not delivered, following restoration of plant / supply by Transend ❖ planned outages (those that have more than 24 hrs notice) ❖ opening of a circuit for system security or power transfer purposes ❖ operation of load shedding scheme, contracted load reduction or generation short falls ❖ mal-operation of the System Protection Scheme ❖ customers exceeding their contracted demand or load on equipment exceeding the rating prescribed by Transend ❖ force majeure events.
Inclusions	Include: ❖ fault outages on all parts of the transmission system ❖ all emergency outages ❖ outages due to fault or other event on connection and network assets owned by Transend.

Definition of Force Majeure

For the purpose of applying the service standards scheme to Transend, 'Force majeure events' means any event, act or circumstance or combination of events, acts and circumstances which (notwithstanding the observance of good electricity industry practice) is 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, NEMMCO, 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.

To avoid doubt where such an event occurs, force majeure specifically includes the event when the outcome includes:

- The collapse of four or more consecutive transmission line towers

- The loss of or damage to two or more switch bays in a terminal station or substation

- The loss of or damage to 11 or more control or secondary cables

- The loss or damage to two or more transformers and capacitors, either single or three phase, connected to a bus

- The loss of or damage to a transformer, capacitor bank, reactor, static var compensator, or synchronous condenser, which loss or damage is not repairable on site according to normal practices.

This is not intended to limit the definition of force majeure, rather to provide guidance in its application.

APPENDIX 5

SKM's report on security criteria

TRANSEND

Transend Networks Pty Ltd

Network Security and Planning Criteria

July 2002

Contents

Document History and Status

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1. Purpose

Sinclair Knight Merz has been engaged by Transend Networks Ltd to determine a capital expenditure programme for augmentation to Transend's regulated network for the revenue reset period 1 January 2004 to 30 June 2009.

As part of the process, network augmentations were developed for a number of load growth and generation scenarios.

This report sets out the network security and planning criteria that were used as a basis for establishing the various network augmentations. The criteria were developed to provide a consistent high level basis for designing the augmentations and are not intended to replace the existing Transend approval processes of feasibility studies, consultation with customers and the preparation of detailed business cases.

In developing these system security and planning criteria, Sinclair Knight Merz has consolidated and reviewed all of its previous work and relevant studies in the area of transmission network design and security standards, including reviews/studies from the New Zealand and the Australian mainland States.

The criteria that have been developed for Transend reflect good industry practice that, in general, are designed to provide economic outcomes to market participants, balanced against the need to ensure a safe, secure and reliable supply of electricity.

In applying these criteria the requirements of Schedule 5.1 of the Tasmania Electricity Code and Schedule 5.1 of the National Electricity Code have been considered. These codes define credible contingency events, minimum service standards and power transfer capabilities of the transmission network.

2. Methodology

The methodology followed in developing the network security and planning criteria was as follows:

- Review of the National Electricity Code (NEC) and the Tasmanian Electricity Code (TEC) requirements;
- Review of existing Transend security and planning criteria;
- Review of the practices in other States and in New Zealand;
- Discussions with Transend planning and operations staff;
- Discussions with Aurora planning staff;
- Consideration of the specific requirements of the Transend network and customers;
- Circulation of draft network security and planning criteria;
  - for comment by Transend and Aurora staff
  - to assess the impact of the criteria on the existing transmission network
- Establishment of the final network security and planning criteria.

Sinclair Knight Merz acknowledges the cooperation and input received from Transend and Aurora staff.

3. Deterministic or Probabilistic Approach

Historically network security has been defined by a set of deterministic criteria that relates to the degree of redundancy built into the power system (transmission lines and substations) and to the magnitude and characteristics of the load.

Such deterministic criteria, if applied rigidly, result in relatively low network utilisation and fail to recognise the dynamic relationship between load, capacity and operating conditions (ambient temperature, weather).

Most Transmission Network Service Providers (TNSP) now do not apply the deterministic criteria without taking into account the load characteristics and real time rating of equipment. A number, including Transend, have installed weather stations to provide real time data on ambient conditions.

Most TNSPs have moved to a probabilistic approach to planning network augmentations. Augmentations are recommended when the total expected cost of not proceeding with the augmentation exceeds the cost of investment required to remove those costs. For example, VENcorp have moved to a probabilistic approach for planning the Victorian transmission network.

However, the application of the probabilistic approach requires a large database on the performance of the network and its components and the value of load not supplied for the different classes of customers. It also requires considerable time and effort to establish and evaluate the various probabilistic scenarios.

For the purpose of the current planning assignment, a deterministic approach has been used. In applying the criteria an assessment of the load at risk has been made. In some cases the commissioning date for an augmentation has been delayed beyond that which would have been required under a strict application of the deterministic criteria.

The determination of what augmentation is required, and the appropriate timing, has been evaluated in three stages as follows:

- Identification of where and when the deterministic criteria were not met.
- Review the characteristics of the load and the security levels provided on the distribution network. In most cases this resulted in a delay in the commissioning date compared with the date required by the strict application of the deterministic criteria.
- Review non-network alternatives to network augmentations including making agreements with generators to provide appropriate security or demand side management options.

4. Review of Security Criteria Practices

4.1 Summary of TNSP Practices

Details of the practices for ElectraNet SA, Powerlink Qld, Transgrid NSW, Vencorp Victoria and Transpower New Zealand are shown in Appendix A.

A summary of the practices of these TNSPs is shown in Table 4-1.

- **Table 4-1 Summary of Security Criteria Practices**

	Security Level		
	N	**N-1**	**N-2**
National Electricity Code	None stated	- Connection points or as defined in connection agreement	- Network N-1 (secure) ie. network returned to a secure state within 30 minutes
Powerlink	Meets their obligations under the Queensland Electricity Act and the National Electricity Code		
ElectraNet	- All loads <10MW - Country radials <30MW	- Country radials >30MW (1)	- 150-600MW (2) - >600MW Adelaide central 100% of MD; remainder 50% of MD
Transgrid	None stated (3)	- Critical parts of the network - Connection points, general (3)	- Connection points high density, N-1 applied simultaneously with N-1 on the distributor network
Vencorp	Probabilistic approach applied. Considered less conservative than the deterministic approach		
Transpower	- <10MW - 10-40MW (4)	- 10-300MW	- CBD loads - 300-600MW

Notes:
(1) $^2/_3$ MD for transmission lines
(2) Continuous capability
(3) Reliability of supply to compliment that provided by distributor
(4) If more than 40 km remote and local generation can limit load shed to 15%

It is noted that the Tasmania Electricity Code (TEC) mirrors the National Electricity Code (NEC) in defining credible contingency events, service standards and power transfer capabilities.

4.2 National Electricity Code Principles

The general principles for maintaining power system security as set out in Section 4.2.6 of the National Electricity Code (NEC) are:

- The power system should operate in a secure operating state and should remain in a secure operating state following a credible contingency event. If, after a contingency event, the secure state is not met, NEMMCO should take necessary action to return the power system to a secure state within 30 minutes.
- Adequate load shedding should be available to restore the power system to a satisfactory operating state following significant multiple contingency events.

Under the NEC Network Service Providers (NSPs) must advise relevant Code Participants and interested parties of any limitations on the power system (Section 5.6.2 – Development of networks within a region).

These principles are the same as those set out in the Tasmania Electricity Code.

Of the TNSP's reviewed, only ElectraNet SA and Transpower NZ have published information setting out their security criteria used for planning augmentations of the power system.

In establishing the augmentations required for the Transend capital expenditure forecasts we have used the security criteria set out in Section 5 of this report. These follow the principles set out in the NEC and TEC and, in general, the practices adopted by ElectraNet and Transpower NZ supported by Sinclair Knight Merz experience with other TNSP's.

Table 4-2 compares the Transend power system with those of Transpower NZ and ElectraNet.

- **Table 4-2 Comparison of Power Systems (1)**

TNSP	Maximum Demand MW	Circuit length of lines (km)		
		275kV	220kV	110/132kV
Transend	1596		1464	1960
ElectraNet	2648	2553		2988
Transpower	5830		5600	4530

Note: (1) Transend and ElectraNet data from Electricity Australian 2001. Transpower data from Transpower Quality Performance Report (1999/00) and Sinclair Knight Merz records.

It is noted that the Transend network is smaller than those of ElectraNet and Transpower. In some cases the load levels set out in the Transend security criteria set out in this report have been "scaled down" to reflect this.

4.3 Development of Transend Security Criteria

The base level of security adopted is the N-1 criteria. Where it is applied to the Transend network (main transmission lines and 220kV to 110kV network transformers), the continuous rating of the equipment is specified. This is because the magnitude of the load flowing on the interconnected network does not always follow the load demand cycle. For example base load power stations connected to the network will inject a constant output into the network over the daily load cycle.

For equipment at exit points the short term overload capacity is specified. This takes advantage of the generally cyclic characteristics of the loads at exit points and the overload thermal capacity of the equipment that is loaded at well below its rating for much of the time.

The through capacity of a sub-station is also limited to 500MW or 50% of the regional load whichever is the lower. This recognises that the magnitude of area loads exposed to "non-credible contingency events" (low probability/high impact events) should be limited (NEC Section 4.2.3(e) and (f)).

At exit points to the network the level of security depends on a number of considerations including:

- Size of load: This defines the size of load that could be lost under a contingent event.
- Sensitivity of load: Loads such as CBD, Hospitals, Water and Sewage, Major Industries are sensitive loads (NEC Section 4.3.2 System Security).

- Number of customers: The number of customers is often linked to size of load.
- Reliability of supply: This defines the SAIDI, SAIFI and other performance targets set for loss of supply for both planned and unplanned maintenance.
- Accessibility for planned and unplanned maintenance: This defines the ability to access the asset to undertake necessary maintenance in acceptable periods of time. Where access is limited based on type of equipment or location then duplication of supply is required.
- Length of line: Long line lengths that require extended time to patrol, locate faults and dispatch plant and equipment to effect necessary repairs coupled with load size and sensitivity of loads may require duplication of supply.
- Value of lost load (NEC Section 5.6.2 Development of networks within a region (g) and (b)): The value of lost load to generators and retailers.
- Value to customer (NEC Section 5.6.2 (g) and (h)): The value of non-supply to customers in respect to loss of production or consequential costs associated with re-establishing the manufacturing process.
- Value to community (NEC Section 5.6.2 (g) and (h)): The value of loss of load in CBD or other critical distribution areas in respect to inability for the community to undertake their normal work or business operations.

Again, for exit points, the base level of security is N-1. For small loads and for loads supplied over long distances, the cost of providing N-1 security may not be economically justified. In these circumstances N level of security is often adopted. Table 4-3 shows the load categories for the application of N security for the Transend criteria together with the load categories adopted by ElectraNet and Transpower.

Table 4-3 Load Categories for N Security

TNSP	Load
Transend	<25MW if line length >40km and local backup is available for essential services
ElectraNet	<10MW (all loads)
	<30MW for country radials
Transpower	<10MW (all loads)
	10-40MW for more than 40km remote loads and 85% local backup

The loads supplied from radial lines greater than 40km in length range from 25MW (Transend) to 40MW (Transpower). The lower level of 25MW was adopted for Transend following discussions with Aurora staff.

While it is noted that Transpower criteria also require 85% local backup, this does not reflect general practice in Australia. The practice proposed for Transend recognises the generally good performance of high voltage single circuit transmission lines with modern protection and automatic reclosing and the generally low isokeraunic levels (thunderstorm days) in Tasmania.

5. Transend Security Criteria

Sinclair Knight Merz recommends, after consideration of all of the issues and varying practices in use around Australia and New Zealand, the following set of network security criteria as the basis for establishing the scope and timing of augmentation of the Transend transmission network due to load growth and network security.

5.1 Definitions

a) Security Levels: The N-1 and N-2 security levels are described in Table 5-1.

Table 5-1 Description of Security Levels

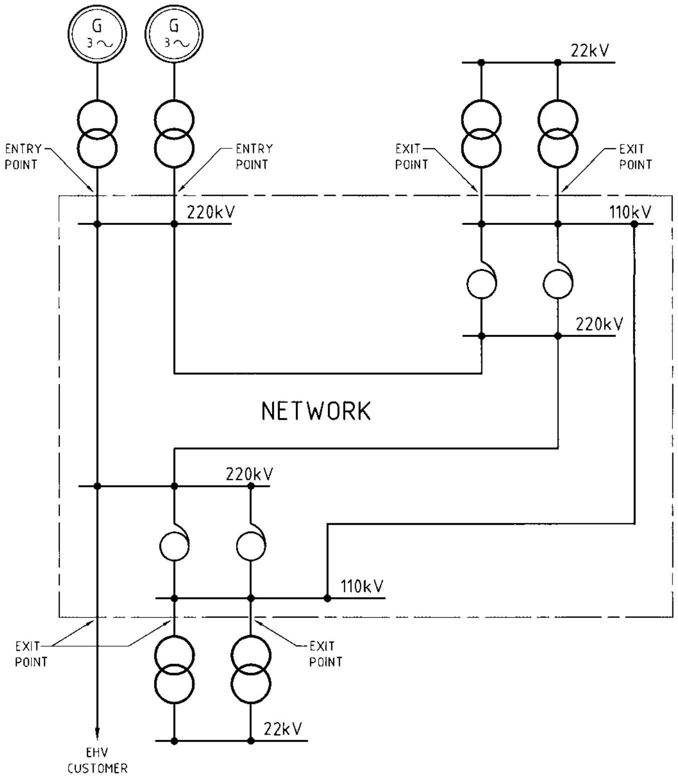
Security Level	Elements under Maintenance	Contingent Event
N-1	None	Loss of a single transmission circuit Loss of a single generator Loss of a network transformer Loss of a capacitor bank/SVC
N-2	A transmission circuit	Loss of a single transmission circuit Loss of a single generator Loss of a network transformer Loss of a capacitor bank/SVC
	A network transformer	Loss of a single transmission circuit Loss of a single generator Loss of a network transformer Loss of a capacitor bank/SVC
	None	Loss of a double circuit line

b) Regional Areas: Three regional areas (North West, North East and South East) have been adopted as shown in Figure 5-1. These regional areas are discussed in Section 5.2 Network Security Criteria.

■ **Figure 5-1 Regional Areas**

c) Security levels have been defined in two categories:
   i) Network: The "common service" interconnected 220 kV and 110 kV Transend network. Refer to Figure 5-2.
   ii) Exit Point: The point on the network where supply is stepped down to distribution network voltages or where a customer takes supply from a Transend bus. Refer Figure 5-2.

■ **Figure 5-2 Network**



d) Sensitive Loads: Loads that require specific levels of network security because of the characteristics of the load, eg. supply to central business districts or to continuous manufacturing or refining process loads.

5.2 Network Security Criteria

In determining network augmentations for the various load growth and generation scenarios the following security criteria were applied:

a) N-1 was the base level of security applied to the network. This criterion was to be met at maximum demand without exceeding the continuous rating of the network plant and equipment.
b) N-2 was applied for supply to regional areas with a maximum demand of more than 500 MW or for supply to sensitive loads. This criterion was to be met at maximum demand without exceeding the continuous rating of the network plant and equipment.
c) For contingent events that would result in islanding of the network it was assumed that special protection schemes are installed.

d) The through capacity of a sub-station was limited to no more than 50% of the regional area maximum demand or 500 MW, whichever is the lower.

In applying these criteria it was assumed that elements of the network could be removed from service for maintenance during periods of low demand, daily or seasonal.

5.3 Network Exit Point Criteria

The security levels applied at network exit points are shown in Table 5-2.

■ **Table 5-2 Network Exit Point Criteria**

Load MW		Security Levels	Transmission Circuits	Bus	Supply Transformers (b)
<10	A	N	1 circuit	1 bus	1 transformer (c)
10-25 (a)	B	N	1 circuit	2 buses or bus section	2 transformers
>25	C	N-1	2 circuits	2 buses or bus sections	2 transformers
	D	N-2 for critical loads	3 circuits	2 or 3 buses or bus sections	2 or 3 transformers

Notes:
(a) If more than 40km then N-1 criterion may apply if load backup for essential services is not available
(b) Firm supply for peak load using short term overload capacity
(c) Assumes spare transformer is available to replace a faulty transformer within a reasonable time

5.4 Application of the Security Criteria

The strict application of the deterministic criteria described above may lead to very conservative levels of reliability and would not reflect current practice for network planning.

In applying the criteria the following factors should be taken into account:

- The past performance of the network.
- Level of security and performance of the distributor's network.
- The frequency of occurrence of the peak load and the characteristics of the load duration curve.
- Dynamic rating of plant and equipment.
- The high cost of strictly applying the criteria in some cases.

5.5 Application of Codes

In establishing the network augmentations that are required to meet load growth and security criteria the requirements of the Tasmania Electricity Code (Schedule 5.1) and the National Electricity Code (Schedule 5.1) are to be met. Both codes are similar in their requirements in defining:

- Operating states
- Credible contingency events
- Minimum standards for network services
- Frequency variations
- Voltage magnitude and fluctuations
- Harmonic distortion
- Voltage unbalance

- Power system stability
- Fault clearing times
- Load shedding facilities
- Automatic reclosure of transmission lines, and
- Rating of transmission lines and equipment

Appendix A Details of Security Criteria in Australia and New Zealand

A.1 ElectraNet SA – Summary of Exit Point Reliability Standards

The reference for the data in **Table A1** is the SAIIR Transmission Code 1st July 2001.

Table A1 – Electranet SA Exit Point Reliability Standards

<table>
<tr><td>Load Category</td><td>1</td><td>2</td><td>3</td><td>4</td><td>5</td></tr>
<tr><td>Applies to</td><td>All loads <10 MW; country radials <30 MW</td><td>Country radials >30 MW</td><td>Loads 10-150 MW, excluding Country radials</td><td>Loads 150-600 MW</td><td>Loads over 600 MW</td></tr>
<tr><td colspan="6">Transmission line capacity</td></tr>
<tr><td>“N”</td><td colspan="5">100% of Agreed MD</td></tr>
<tr><td>“N-1” (any combination of Transmission, Distribution, Generation, Load interruptability)</td><td>Nil</td><td>2/3 of Agreed MD</td><td>100% of Agreed MD</td><td colspan="2">See below</td></tr>
<tr><td>“N-1” continuous capability</td><td colspan="3">None stated</td><td colspan="2">100% of Agreed MD</td></tr>
<tr><td>“N-2” (any combination of Transmission, Distribution, Generation, Load interruptability)</td><td colspan="4">None stated</td><td>“Adelaide central” 100% of Agreed MD; remainder 50% of Agreed MD</td></tr>
<tr><td>Time to restore contracted line capacity after interruption</td><td colspan="3">2 days (best endeavours)</td><td>12 hours (best endeavours)</td><td>4 hours (best endeavours)</td></tr>
<tr><td colspan="6">Transformer Capacity</td></tr>
<tr><td>“N”</td><td colspan="5">100% of Agreed MD</td></tr>
<tr><td>“N-1” (any combination of Transmission, Distribution, Generation, Load interruptibility)</td><td>Nil</td><td colspan="2">100% of Agreed MD</td><td colspan="2">See below</td></tr>
<tr><td>“N-1” continuous capability</td><td colspan="3">None stated</td><td colspan="2">100% of Agreed MD</td></tr>
<tr><td>“N-2” (any combination of Transmission, Distribution, Generation, Load interruptibility)</td><td colspan="4">None stated</td><td>“Adelaide central” 100% of Agreed MD; remainder 50% of Agreed MD</td></tr>
<tr><td>Restoration time to full capacity after transformer failure</td><td colspan="4">4 days (best endeavours)</td><td>2 days (best endeavours)</td></tr>
<tr><td>Spare transformer requirement</td><td colspan="3">Keep in stock at least one spare capable of replacing the installed transformer capacity</td><td colspan="2">None stated</td></tr>
<tr><td>Period allowed to comply with required contingency standard, where applicable</td><td>N/A</td><td colspan="4">12 months (best endeavours); maximum 3 years</td></tr>
</table>

A.2 Transgrid NSW

The reference for the data in **Table A2** is the TransGrid 2001 Planning Report.

Table A2 – TransGrid Levels of Security

Category	Level of Security	Comments
Critical parts of the network	N-1	Capacity of interconnectors is the short-time capacity to maintain secure operation after a single contingency in the normal state. Transgrid would initiate augmentation to meet its N-1 criterion
Connection Points - General	N-1 at peak demand	Transgrid aims to provide a level and reliability of supply at connection points that compliment that provided by the Distributor. Country Energy example; N-1 reliability provided for a load area over 15 MW Consistent with this Transgrid aims to provide N-1 reliability at the peak demand that is forecast to be exceeded one year in two
Connection Points – Supply to high-density urban and central business districts	N-1 applied simultaneously with N-1 on the distributor network, i.e. N-1 applied separately to the two networks	Based on the following factors: ▪ the importance and sensitivity of the Sydney area load supply to supply interruptions; ▪ the high cost of applying a strict N-2 criterion to the 300 kV cables network; ▪ the large number of elements in the 132 kV network; ▪ the past performance of the cable system; and ▪ the extensive outage time that can result from a cable failure

A.3 VENcorp Victoria

VENcorp published a Consultation Paper – Electricity Transmission Network Planning Criteria, in February 2001 and an Advice to Stakeholders at the conclusion of the consultation process in July 2001.

It was concluded that, "VENcorp will continue to apply a probabilistic approach, where applicable, except in those cases where VENcorp i.e. required to meet a performance under Schedule 5.1 of the Code.

VENcorp applies a 'probabilistic' approach to network planning. Under this approach, transmission augmentation proceeds when the total expected (probability-weighted) cost of not proceeding exceeds the cost of investment required to remove these costs. However, implicit in use is acceptance of the risk that there may be circumstances when the planned capability of the network will be insufficient to meet actual demand. (refer Consultation Paper).

The consultation paper defines the deterministic planning standards as set out in **Table A3**.

Table A3 – Definitions of Deterministic Criteria

Degree of Planning Standard	All plant within ratings, and within operating limits?	Is the system secure for a second critical contingency without load shedding?	Will load need to be shed after the second critical contingency?	Comments
N-1 Satisfactory	Yes	No	Yes	On loss of a critical element, load must be shed to return the power system to a secure state
N-1 Secure	Yes	Yes	Yes	On loss of a critical element, load can be maintained indefinitely, and must only be shed following a second contingency.
N-2	Yes	Yes	No	No load is shed following a second contingency.

A.4 Transpower NZ

Security Guidelines

The recommended security guidelines are:

- (N-1) security criterion to meet peak demand for the credible worst-case generation dispatch scenarios. It is assumed here that no circuits are taken out for planned maintenance during peak load period.
- For regions with net transfer more than 600 MW, (N-2) security criterion to meet summer peak demand since circuits are taken out for maintenance during summer period. This should be based on normal dispatch scenarios, not extreme dispatch scenarios.
- For regions with net transfer less than 600 MW, if customers do not agree to load curtailment during summer period before contingency to maintain (N-1) security when a circuit is out on planned maintenance, System Protection Schemes (SPS) should be installed so that load is shed only post-contingency. These SPS should be armed only when circuits are taken out for maintenance.
- Any load that has significant impact on business should have N-2 security, in particular CBD loads, for winter and summer peak load conditions. The N-2 security could be with or without break depending on the situation.

The contingency events to be considered in testing capability of the system to provide N-1 or N-2 security are listed in the table below.

Table A4.1 – Contingency Events

Security Level	Elements on maintenance	Contingent event
N-1	None	Loss of a single transmission circuit Loss a single generator Loss of an HVDC Pole Loss of an interconnecting transformer Loss of a capacitor bank
N-2	A transmission circuit	Loss of a single transmission circuit Loss a single generator Loss of an HVDC Pole Loss of an interconnecting transformer Loss of a capacitor bank / condenser / SVC
	An interconnecting transformer	Loss of a single transmission circuit Loss a single generator Loss of an HVDC Pole Loss of a capacitor bank / condenser / SVC
	None	Loss of a double circuit line Loss of a single bus section

Summary of Grid Exit Point Reliability Standards

Table A4.2 – Grid Exit Reliability Standards

Load (MW)	Basic Criterion	Transmission circuits	Bus	Supply Transformers
< 10	N	1 circuit	1 bus or bus section	1 x 3 phase
10 – 40 [a]	N	1 circuit	2 buses or bus sections	4 x 1 phase[c] or 1 x 3 phase, if backed up from alternative supply point
10 - 300	N-1 [c] N-2 for CBD loads [d]	2 circuits	2 or 3 buses or bus sections	4 x 1[c] phase or 2 x 3 phase or 7 x 1[c] phase or 3 x 3 phase[e] Firm supply of peak demand using any short term overload
300 - 600	N-2[c]	3 circuits on 2 routes	2 or 3 buses or bus sections [b]	4 x 1[c] phase or 2 x 3 phase or 7 x 1[c] phase or 3 x 3 phase[e] Firm supply of peak demand using any short term overload
> 600	Loss of station	Supply should be diversified across more than one major terminal substation		

Notes:

(a). if more than 40 km remote and local generation can limit load shed to 15%

(b). Supply should not be lost after a single contingency while one bus is out of service for maintenance

(c). With single phase transformers there would be a break in supply for outage of transformer. This is to replace the faulty unit.

(d). Could be with or without break depending on the quantum of load

(e). For 33 kV GXP capacity s limited to a maximum of 240 MVA with 3 x 100 MVA transformer with overload capacity of 120 MVA

A.5 Powerlink

EXTRACTS FROM PUBLIC DOCUMENTS

FROM "REQUEST FOR INFORMATION": "Emerging Transmission Network Limitations Brisbane South/Logan Region (including part of the Greater Brisbane metropolitan area, the Port of Brisbane and TradeCoast industrial area)
Powerlink Queensland, June 2001"

"Powerlink Queensland has a responsibility to ensure its network is operated with sufficient capacity to provide network services to customers[1]. If technical limits of its transmission system will be exceeded, Powerlink is required to notify Code Participants within the time required for corrective action."

"Transmission Planning Criteria

As a transmission network service provider (TNSP), Powerlink must comply with technical standards in the National Electricity Code. In particular, requirements relating to reliability and system security contained in Schedule 5.1 of the Code are relevant to planning for future electricity needs. This schedule includes details of credible contingencies to be considered in planning and operating the transmission network.

The National Electricity Code allows varying levels of reliability to be specified in connection agreements between Powerlink and connected Code Participants. Examples of differing levels of reliability include:

- 'N-1': able to meet peak load with the worst single credible fault or contingency
- 'N-2': able to supply all peak load during a double contingency, and
- 'System Normal': the absolute minimum level of reliability required. Defined as the ability to supply all load with all elements of the electricity system intact (ie – supply cannot be maintained during a fault or contingency without loss of load).

Under the present arrangements, Powerlink plans its system in the southeast Queensland area to satisfy 'N-1' criterion. While Powerlink recognises that similar metropolitan and major industrial areas in other States may have slightly higher standards, Powerlink considers that 'N-1' (ie – able to meet peak load with the worst single contingency) is the appropriate criterion to meet its current Code and licence obligations.

The assessment of emerging network limitations in section 5.0 therefore covers the capability of the existing network to maintain supply during the loss of any single element (Ie: N-1 criterion). In the Brisbane South/Logan region, the most critical elements are the Blackwall-Belmont and Swanbank-Loganlea/Belmont 275kV circuits.

[1] Powerlink's transmission authority includes a responsibility "to ensure as far as technically and economically practicable, that the transmission grid is operated with enough capacity (and if necessary, augmented or extended to provide enough capacity) to provide network services to persons authorised to connect to the grid or take electricity from the grid." (Electricity Act 1994, S34.2).

Some information is provided in section 5.0 on the supply capability during double contingencies. However, at present, Powerlink does not plan its system to satisfy N-2 criterion (ie – to withstand low probability double contingencies on the transmission grid), or any criterion higher than N-1."

FROM "DRAFT RECOMMENDATION": "Emerging Transmission Network Limitations – Brisbane South/Logan Region (including part of the Greater Brisbane metropolitan area, the Port of Brisbane and TradeCoast industrial area) Powerlink Queensland, 8th March 2002"

"Powerlink considers that 'N-1' (that is, the ability to supply all load with any single network element out of service) is the appropriate planning criterion for the Brisbane South/Logan area to meet its current reliability obligations under the Electricity Act and technical standards in the National Electricity Code[2]."

[2] The Powerlink system has not been designed to withstand low probability, simultaneous double contingencies. However, solutions to address the emerging limitations during single contingencies may reduce or eliminate the severe loss of supply, which occurs during a double circuit outage of the 275kV lines supplying the Brisbane South/Logan area.

APPENDIX 6

Development capital expenditure projects

APPENDIX 6 – DEVELOPMENT CAPITAL EXPENDITURE PROJECTS

This Appendix outlines the development capital expenditure projects considered by SKM, when assessing Transend's future development capital program for the forthcoming regulatory period. The projects listed were identified by SKM in their scenario analysis, completed in September 2002. Transend has made some refinements to the project details, as new information has become available.

After SKM's analysis was complete Transend also received more enquiries about, and applications for, generation connection. Aurora also indicated that towards the end of the revenue period some alternative sites may require development for future load growth. Transend has had insufficient time to undertake scenario analysis of all these prospective developments. The list of projects in this appendix is therefore not exhaustive.

The projects considered by SKM are divided into two categories:

- ***Fixed projects*** Those projects that analysis suggests are almost certain to proceed in the forthcoming regulatory period. General load growth, system security requirements or committed customer connections typically drive fixed projects. They are accorded a 100% probability in SKM's analysis, despite the uncertainty in load and generation forecasts.

- ***Variable projects*** Those projects that typically depend on specific customer-driven developments proceeding, such as new generation proposals. Transend's analysis shows that these projects will proceed only if particular growth scenarios eventuate and/or proponents complete identified projects within present timeframes. The probabilities of these variable projects proceeding vary from 10% to 80% in SKM's analysis.

It is also proposed that any additional projects, to those identified by SKM, be treated as variable projects for regulatory purposes.

A significant number of the fixed projects have been subject to public consultation, economic analysis and endorsement by the Reliability and Network Planning Panel, in accordance with the process outlined in the Tasmanian Electricity Code.

1. FIXED PROJECTS

1.1 Southern augmentation project

The Southern augmentation project provides a second 220 kV injection point into the Hobart area and the southern part of the Transend network.

The project will:

- provide a more secure supply to Hobart and southern part of the network
- reduce the load and reliance on Chapel Street Substation
- remove reliance on the availability of Gordon power station
- reinforce the existing weak eastern shore supply
- reduce the load on the Chapel Street and Creek Road 110 kV circuits to Risdon Substation

- allow removal of some of the aged 110 kV infrastructure.

The scope of work for the Southern augmentation project is set out below:

a) Establish a new 220 kV Substation at the existing Lindisfarne Substation:

- Establishment of a 220 kV switchyard at the existing Lindisfarne substation with the installation of two 200 MVA, 220/110 kV autotransformers and extension of the existing 110 kV switchyard.
- Provision of new 220 kV, single circuit breaker feeder bays and bus work at both Liapootah and Tarraleah substations.
- Route selection, easement acquisition and construction of a double circuit 220 kV, 637mm² transmission line from Liapootah to Lindisfarne.
- Rearrangement of 110 kV transmission lines into Risdon.
- Establish a new Bridgewater to Lindisfarne 110 kV line.

b) Waddamana – Bridgewater Upgrade

- Upgrade the Waddamana-Bridgewater line to provide increased capacity from this line.

  Note: Within the same corridor, it is proposed to decommission the Waddamana-Lindisfarne 110 kV line which is 80 years old and in very poor condition. Costs for this decommissioning have not been included in the fixed development capital costs, but are included on the operating budget.

c) Tungatinah-Lake Echo-Waddamana

- Both the TU-LE-WA No1 and No2 110 kV single circuit flat lines are in need of maintenance and have substandard clearances. The preferred option is to decommission the No2 line (operating budget) and retension the No1 line to a higher design rating (nominally 71^{0}C). The project involves approximately 35-route km of line retensioning.

d) New Norfolk – Chapel Street and Chapel Street-Kingston 110 kV circuits Reconnection

- This project involves rearrangement of the existing 110 kV circuits south of New Norfolk. The drivers for this project are to address issues with old lines with substandard clearances, together with system rearrangements to facilitate 220 kV connections. The scope of the work has yet to be closely defined, as there are a number of possible options, and different circuit connections. Connection into Creek Road Substation may also be an alternative to connection into Chapel Street Substation.

Total forecast Southern augmentation project cost is $ 55.4 million ($37.2 million line, $18.2 million substation).

Note: The overall Southern augmentation project includes a number of projects that are in the renewal capital program rather than in the development capital program.

These projects comprise:

- Tarraleah to New Norfolk 110 kV line compliance and refurbishment ($4.1 million)
- New Norfolk to Chapel St, (Line L462), 110 kV line compliance ($0.8 million)
- Line dismantling costs ($4.1m)
- Fourth Transformer replacement at Chapel Street Substation ($2.5 million).

The Southern augmentation project impact on the renewal capital program is $11.5 million.

1.2 Tasmanian Wholesale Electricity Market (TWEM)

The Transend Tasmanian Wholesale Electricity Market project (TWEM project) was formed in August 2001.

The purpose of the TWEM Project is to:

- Participate in the establishment of the framework for the Tasmanian Wholesale Electricity Market.
- Ensure Transend is ready for the entry of Tasmania into the National Electricity Market (NEM) via the connection of Basslink.
- Facilitate the connection of Basslink to the Tasmanian transmission system.

This project is intended to coordinate with the work of the Tasmanian Government National Electricity Market Implementation Project Plan.

It is intended that Tasmania will join the National Electricity market (NEM) six months prior to the commissioning of Basslink. Basslink commissioning is scheduled for November 2005 and NEM Entry is scheduled for May 2005.

In order to achieve Basslink commissioning and NEM entry, Transend must:

- install NEC-compliant wholesale metering at Transend/Aurora interfaces
- install quality-of-supply monitoring equipment to measure compliance with connection agreements and Schedule 5.1 of the NEC
- replace field transducers associated with the state estimator, to meet NEMMCO's requirement that the state estimator converges reliably
- install back-up protection schemes to prevent the system collapsing in the event of non-credible contingencies (such as the simultaneous tripping of multiple transmission lines, or complete failure of the primary protection system). These systems are required under Schedule S5.1.9 of the NEC to protect against over- and under-frequency events and under- and over-voltage events.

The scope of the project can therefore be summarised as:

- Inter-company metering – Transend/Aurora connection points
- Quality of supply monitoring
- State Estimator (upgrade field equipment)
- Systems to ensure ongoing system security
- (Under frequency / over frequency and under voltage / over voltage protection schemes).

Estimated cost is $5.1 million of which $1.0 million has an expected commissioning date before 1 January 2004.

1.3 Norwood - Scottsdale - Derby Redevelopment

The 110/88 kV transformers at Norwood Substation and the 88 kV transmission line between Norwood, Scottsdale and Derby are 65 years old and are approaching the end of their economic lives. In addition the transmission line to Scottsdale at times operates near its design limit for the existing combined maximum demand of Scottsdale and Derby substations. The combined Scottsdale and Derby maximum demands are approaching 25 MW where N-1 security is considered appropriate.
For this project it is proposed to construct a new 110 kV double circuit line to Scottsdale and a new 110 kV single circuit line from Scottsdale to Derby.

No provision has been made in rating the 110 kV line to Scottsdale and Derby for the possible connection of significant wind generation on the north east coast as a fixed project. Any such increment to the design capacity would be considered as a variable project.

The scope of the work for the project is set out below:

- Install two 110 kV single circuit breaker feeder bays (existing breakers) at Norwood substation.
- Install one 110 kV single circuit breaker feeder bay and bus coupler at Scottsdale substation.
- Construct a double circuit 110 kV, 150mm^2 transmission line from Norwood to Scottsdale.
- Construct a single circuit 110 kV, 150mm^2 transmission line from Scottsdale to Derby.
- Carry out appropriate transmission line reconnections.
- OPGW procurement and installation.

Total cost: $17.5 million ($14.5 million line, $3.0 million substation)

1.4 Mowbray 110/22 kV Substation and Line Development

Mowbray substation is proposed as part of the overall Launceston area supply upgrade. It will provide additional feeder connections to Aurora to improve distribution feeder performance and will also reduce the loading on Trevallyn and Norwood substations.

The scope of the work for the project is set out below:

- Construct a new 110 kV line from Trevallyn Substation to a new substation site in Derby St, Mowbray (Includes two sections of underground 110 kV cable totalling 1.2 km, 750 m of 110 kV pole line and 150m overhead crossing of the Tamar river)
- Construct a new single transformer substation at Mowbray with 2 x 20 MW, 22 kV distribution feeder backup connections with Trevallyn Substation.

The Transend total estimated project cost is $8.3 million of which $5.3 million will be spent after the commencement of the revenue review period.

Total cost: $ 8.3 million ($3.3 million line, $5.0 million substation)

1.5 Risdon Substation 33 kV Development

Provision of 33 kV supply from Risdon substation is part of the Hobart Area Supply Upgrade (HASU) strategy. Aurora has submitted a connection application for 33 kV supply from Risdon as part of the process for upgrading its existing 22 kV subtransmission from 22 kV to 33 kV. In the next stage of the program Aurora plans to convert its East Hobart zone substation from 22 kV to 33 kV and supply it from Risdon.

The work is expected to be done during the 2003 - 2004 financial year. The total project cost is estimated at $8.8 million with $6.4 million to be spent after the start of the revenue review period.

The scope of the first stage of HASU is set out below:

- purchase and install two 50/60 MVA transformers (one existing transformer is dual wound to 22 kV or 33 kV)
- establish a new 33 kV switchboard (9 feeders, 2 bus coupler, 3 transformer)
- remove 1 x 30 MVA , 1 x 30/50 MVA existing transformers and switchgear.

Total cost $8.8 million (substation).

1.6 Creek Road Substation 33 kV Connections

As part of its HASU strategy, Aurora will be converting a number of its zone substations from 22 kV to 33 kV. An amount of $350 thousand has been estimated to provide for work at Creek Road Substation for the connection of the feeders at 33 kV. Of this amount $110 thousand would be spent and commissioned prior to 1 January 2004.

1.7 Reactive Support Program

The installation of fixed shunt capacitors at various locations across the State is required to maintain appropriate voltage levels and system voltage stability. A reduction in reliance on the generators for reactive support will also provide a greater capacity for dynamic response from the generators during system faults.

Transend network studies have identified the location and scope of installations required on the EHV and HV networks. The need for reactive support on the EHV network is supported by the SKM network studies.

A total of 300 MVAR of reactive support is planned for installation at a total estimated cost of $10.1 million. However, Chapel Street reactive support at a cost of $3.2 million will be built and commissioned before 1 January 2004 leaving $6.9 million expenditure within the 2004 - 2009 regulatory period.

1.8 Smithton Second Circuit

Smithton Substation is currently supplied by a single circuit radial 110 kV supply. It is proposed to establish a second circuit on the existing double circuit tower line between Port Latta Tee and Smithton Substation.

The cost of this project is $1.6 million. Expenditure of approximately $1.4 million will be prior to 1 January 2004.

1.9 George Town Substation 220kV kV security augmentation (bus rearrangement)

George Town Substation is becoming a more important electrical node in the system due to the proposed Basslink connection and Bell Bay Power Station upgrade and usage. Total connection obligations potentially exceed 1400 MW.

The longer-term strategy for George Town Substation has been to improve the overall security of the 220 kV and 110 kV busbar arrangements. In general, the concept has been to implement breaker and a half arrangements.

However, full conversion of the buses to breaker and a half for all circuits would be a significant cost and difficult to justify as bus faults are considered as low probability non-credible contingencies. A prime advantage of breaker and a half arrangements is the ability to remove circuit breakers for maintenance without removing elements from supply. However, with advances in circuit breaker design, the requirement for availability for maintenance is now of lesser importance.

Detailed design and justification will be required for this project. For the purpose of the revenue review, costing has been based on nominally converting four 220 kV circuits to breaker and a half arrangement.

No rearrangement of the 110 kV bus is provided for in the next regulatory period.

An allowance of $3.5 million has been made for this project

1.10 Sheffield Substation Security

The load flowing through Sheffield Substation is in excess of 500 MW at present with all the generation from the Farrell area passing through this one location. Whilst the probability of the loss of Sheffield substation due to some catastrophic event is very low the impact on supply in Tasmania of such an event would be high.

Transend is investigating ways of improving security with modest expenditure and SKM supports this initiative. An allowance of $3.0 million has been made for this work.

2. VARIABLE PROJECTS

2.1 AURORA CONNECTIONS

2.1.1 Southwood wood-processing facility

An integrated timber processing project is proposed for development approximately 20 km from Knights Road Substation. The project incorporates wood waste generation of electricity and approximately 30 to 40 MW will be exported from the site.

To service the project Transend proposes to establish a new 110/11 kV substation at Southwood and construct a new 110 kV transmission line from Southwood Substation to Knights Road Substation. Southwood Substation will also provide supply to a number of individual customers related to the timber processing. These will be Aurora customers and the expected load is approximately 5 MW.

2.1.2 Mt Nelson 110/11 kV Substation Development

A new substation in the Mt Nelson area is a possible requirement late in the revenue-review period but with low probability. The assessment by Aurora is that for the high load growth scenario it will be required by 2008 - 09. Transend currently owns a site of land in the Mt Nelson area for the future substation.

2.1.3 Wynyard Area Upgrade

Aurora has indicated that a new substation in the Wynyard area could be required within the revenue-review period. It depends largely on the potential for industrial development proceeding in the area. The proposed site for the new substation is adjacent to the existing Burnie to Port Latta 110 kV line.

2.1.4 Hadspen Transformer Augmentation

The Launceston/Trevallyn area has had significant growth and this growth is forecast to continue over the revenue review period.

Trevallyn Substation is now overloaded under peak demand conditions and Transend is about to construct a 110/22 kV substation at Mowbray with two 50 MVA transformers to reinforce supply in the area and to transfer load from Trevallyn.

At the forecast demand growth of over 2% pa in the area, further 110 kV to 22 kV transformation will be required towards the end of the revenue review period. The requirement for 22 kV at Hadspen is also dependent upon Aurora’s strategy for distribution feeder rearrangements in the area.

For the purposes of this analysis it has been assumed additional 110 kV to 22 kV transformation will be achieved by establishing a 22 kV bus at Hadspen Substation with a commissioning date of May 2007.

The scope of work for the Hadspen 110/22 kV development is set out below.

- establish two 110 kV single circuit breaker transformer bays.
- supply and install two 25 MVA 110/22 kV transformers.
- supply and install 22 kV single bus switchgear with two transformer, one bus tie and five feeder circuit breakers.

2.1.5 Lindisfarne Transformer Augmentation

The maximum demand at Lindisfarne Substation is 52 MVA (August 2001) with a firm N-1 short time rating for the transformers of 54 MVA.

Transformer augmentation for the low load growth scenario will not be required during the revenue review period.

Demand will reach the firm transformer capacity in years 2005 - 06 and 2006 - 07 respectively for the medium and high load growth scenarios. However, Aurora has indicated that through its planned distribution feeder works that Rokeby Substation will have load transferred to it from Bellerive Zone substation, thereby reducing some of the load on Lindisfarne Substation. Accordingly the need to upgrade Lindisfarne Substation is not required until 2008 - 09.

This scope of work is set out below.
- remove and store the two existing 45 MVA transformers.
- supply and install two 60 MVA 110/220 kV transformers.
- carry out associated control and protection modifications.

2.1.6 Additional Aurora feeder connections

Aurora has indicated the possible need for over thirty additional feeder connections during the regulatory review period. The need will depend on load growth and new customer connections. Approximately half can be provided from existing assets and other planned projects, however there needs to be specific provision for additional assets to accommodate the other connections.

2.2 GENERATION CONNECTION ASSETS

2.2.1 Tarraleah 220 kV connection to Liapootah Stage 1 and Stage 2

Hydro Tasmania proposes to convert the output from its generators at Tarraleah Power Station from 110 kV to 220 kV. The conversion is currently being considered in two stages. The first stage involves part conversion of Tarraleah generation to 220 kV and a new 220 kV line connection between Tarraleah and Liapootah. The second stage is conversion of the remainder of the Tarraleah generation to 220 kV and installation of a 220/110 KV autotransformer to maintain the 110 kV connection between Tarraleah and Tungatinah substations.

The general scope of the work is set out below.
- Extension of Liapootah switchyard with one 220 kV, single circuit breaker feeder bay
- Establishment of a 220 kV switchyard at Tarraleah and the reconnection of the two existing generator transformers from 110 kV to 220 kV operation
- Install one 220/110 kV transformer at Tarraleah.

2.2.2 Woolnorth Wind

Hydro Tasmania plans to establish a 110 kV line from its Woolnorth wind farm and connect at Smithton Substation. Connection assets requiring at least one 110 kV circuit breaker will be required. See 2.3.2 and 2.3.3 for network requirements.

2.2.3 Robbins Island Wind (110 kV connection bay)

Approximately 135 MW of wind generation is under consideration in the north west of Tasmania from Robbins Island and Jims Plains. Connection assets requiring at least one 110 kV circuit breaker will be required. See 2.3.2 and 2.3.3 for network requirements.

2.2.4 Musselroe Wind to Derby (110 kV connection bay)

Hydro Tasmania plans to establish a 110 kV line from its Musselroe wind farm and connect at Derby Substation. Connection assets requiring at least one 110 kV circuit breaker will be required. See 2.3.4 for network requirements.

2.2.5 Heemskirk Wind (220 kV connection bay)

Approximately 160 MW of wind generation is under consideration on the west coast of Tasmania. Connection is envisaged at 220 kV requiring at least one 220 kV circuit breaker.

2.2.6 Brighton Waste to Energy (11 kV connection)

Test Energy proposes to burn waste refuse at high temperature and generate power as the by-product. The proposed plant is in the vicinity of Bridgewater substation. The size of the generation is uncertain but present indications are that it will be approximately 15 MW.

It is assumed it will be embedded generation with 2 x 11 kV feeder connections at Bridgewater Substation.

2.2.7 George Town Waste to Energy (22 kV connection)

A green waste energy plant of approximately 20 MW is proposed near George Town Substation by 2004. It will potentially be embedded generation with 2 x 22 kV feeder connections at George Town Substation.

2.2.8 Bell Bay connection for 350 MW

The capacity of the circuits from Bell Bay to George Town Substation will need to be increased to accommodate a potential 350 MW output. Potentially, a third 110 kV circuit could be required. Connection assets requiring at least one 110 kV circuit breaker will be required.

2.2.9 Southern gas fired power station

There is potential for a new gas fired power station in the south of Tasmania with connection at the 110kV level. Connection assets requiring at least one 110 kV circuit breaker would be required.

2.3 SHARED NETWORK

2.3.1 Farrell to George Town 220 kV (new line)

Significant additional wind generation (>150 MW) injecting into the Farrell 220 kV will require an additional 220 kV circuit between Farrell and George Town. This is required under the N security criteria that apply with export from Tasmania over Basslink.

The scope of work is set out below:

- Miscellaneous work on the spare 200 kV bay at Farrell Substation.
- Establishment of a 220 kV, single circuit breaker, feeder bay at George Town.

- Route selection, easement acquisition and construction of a 155 route km single circuit 220 kV, 637mm² transmission line between Farrell and George Town.

The 220 kV line bypasses Sheffield substation for network security reasons.

2.3.2 Upgrade circuits to Smithton (north-west generation 65-136 MW)

For connection of up to 136 MW of wind generation as proposed for Stage 3 of the Woolnorth wind farm, it will be necessary to re-conductor approximately 70 route km of double circuit 110 kV line between Smithton and Burnie.

2.3.3 Smithton to Sheffield 220 kV line (new line)

Two proponents are proposing wind generation on the north west coast of Tasmania; at Woolnorth (maximum generation 136 MW) and at Robbins Island/Jims plains (maximum generation 135 MW). Both are planned for commissioning in about 2005.

For wind generation in the area up to a total of about 270 MW the amount of network augmentation was reviewed taking this into consideration and identified as follows:

- establishment of a 220 kV switchyard at Smithton Substation
- construction of a single circuit 220 kV transmission line between Smithton and Sheffield
- addition of a 220 kV bay at Sheffield Substation.

This work would be in addition to reconductoring the 110 kV line between Smithton and Burnie referred to in 2.3.2.

2.3.4 Musselroe wind (increment to Norwood-Scottsdale- Derby line)

Costing done for the Norwood-Scottsdale-Derby upgrade project (Section 1.3) has not included additional capacity to provide for the Musselroe wind generation output. The current Norwood-Scottsdale-Derby upgrade project provides for double circuit 154mm^2 conductor between Norwood and Scottsdale and single circuit to Derby. To accommodate the Musselroe wind farm output a larger conductor size may be needed, particularly when loss calculations are considered. In addition, the single circuit to Derby Substation would need to be upgraded.

2.3.5 Reactive Support George Town

Under certain operating conditions with Basslink exporting in excess of 450 MW an additional 70 MVAR of support is required at George Town Substation. Under operating conditions associated with high wind generation, a further 30 MVAR is required.

APPENDIX 7

NECG's cost of capital report

Weighted average cost of capital for Transend

Submission to the ACCC by the Network Economics Consulting Group

March 2003

Contents

1 Introduction

Transend Networks Pty Ltd (Transend) has asked the Network Economics Consulting Group (NECG) to prepare a report for the Australian Competition and Consumer Commission (ACCC) on the appropriate weighted average cost of capital (WACC) it should be allowed to earn on its regulated transmission assets.

It is important to recognise the role of the assessment of the WACC in a regulatory review, which is to remunerate past investment and to provide an indication of the rate at which new investment will be remunerated. As such, the WACC should reflect alternative investment opportunities available to investors and thereby the (risk adjusted) opportunity cost of capital.

Consistent with regulatory decisions across Australia, we use the Weighted Average Cost of Capital (WACC) model to estimate the appropriate rate of return to be earned by Transend on its assets. The standard approach used in Australia can be formulated to capture the value of imputation credits by adjusting the net cash flows to be discounted or by including the impact in the firm's weighted average cost of capital. In this report we have adopted the former approach, consistent with the approach of the ACCC.

Determination of the appropriate WACC will vary depending upon how cash flows or earnings are being discounted. Consistent with the ACCC's approach we have defined cash flows in nominal terms and after tax. The effect of tax is then incorporated in the cash flows. This produces a "vanilla" WACC defined as:

$$WACC = r_e (E/V) + r_d (D/V) \qquad \textbf{(1)}$$

where

r_e	=	cost of equity capital,
r_d	=	cost of debt capital,
E	=	market value of equity,
D	=	market value of debt, and
V	=	market value of the firm (E+D).

Using this formulation we determine the required return on equity, consistent with standard regulatory practice, using the Capital Asset Pricing Model (CAPM). Under the CAPM the required return on equity is expressed as a premium over the risk free return as follows:

$$E(R_e) = R_f + b^* [E(R_m) - R_f] \quad (2)$$

where

R_e	=	cost of equity capital;
R_f	=	risk free rate of return;
R_m	=	market rate of return;
E(.)	=	indicates the variable is an expectation; and
b	=	systematic risk parameter ("equity beta").

The CAPM assumes that returns are normally distributed around the mean. Where this assumption is violated then estimating the required return on equity using the CAPM may either over- or under-estimate the required return on equity. Most specifically where the business is subject to regulatory or market arrangements that limit the distribution of returns above the mean then investors will require compensation for holding such assets. In Transend's submission, these asymmetric risk are treated as a cash flow item and are not included in the WACC.

This report is structured as follows:

- section 2 assesses the appropriate proxy for the risk free rate;
- section 3 sets out the appropriate market risk premium;
- section 4 assesses capital structure and the cost of debt;
- section 5 considers systematic risk;
- section 6 assesses the appropriate value of gamma; and
- section 7 sets out our recommended WACC and individual parameter values.

Conclusion

We estimate that as of 4 February 2003 the nominal "vanilla" WACC for Transend is 8.80%. This includes the following components:

- Risk-free rate of 5.24% based on the 10-day average of the 10-year Commonwealth bonds as at 4 February 2003;
- a market risk premium (MRP) of 6.0%;
- an asset beta of 0.45;
- the cost of debt of 144.5 basis points above the risk-free rate; and
- a gamma of 0.50.

2 Risk free rate

The risk-free rate of return in the CAPM is generally derived from government bonds rates. The key issues for the risk free rate are twofold: the appropriate bond maturity to adopt, and the period over which any averaging of the rate is taken place.

2.1 Bond maturity

It should be expected that the bond maturity adopted in the CAPM should reflect the decision that an efficient firm would reach in choosing its capital structure.

In non-regulated applications, companies investing in long-lived assets generally finance those assets with debt consistent with the average life of the assets[1] used in the business.[2] This allows the company to service its debt from the revenue generated by the assets without being exposed to interest-rate risk. While both the assets and debt will generally have some potential to be liquidated before maturity, it is normally the intention of management to keep both in place through to the end of their lives.

In a regulated setting, the key question becomes whether it is more efficient to adopt a financing structure consistent with the regulatory period or the asset life. As can be seen in table 1, the position of the ACCC, in setting the risk free rate based on the length of the

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1 Actually a company would match 'duration' of its debt and assets. Duration is a measure developed for bonds. It is a weighted average of the maturity of all the income streams from a bond. So the duration of a bond with regular principal payments would have a lower duration than a bond of the same total life that was all paid at maturity. The duration of an asset will generally be roughly half its useful life.

2 For example, see E. Brigham and L. Gapenski, *Intermediate Financial Management* (5th ed), 1996 (The Dryden Press, Fort Worth), p 544, S. Ross, R. Westerfield and J. Jaffe, *Corporate Finance* (5th ed.), 1999 (Irwin/McGraw-Hill), p 666, and A. Shapiro and S. Balbirer, *Modern Corporate Finance*, 2000 (Prentice-Hall, Upper Saddle River, New Jersey), p 84.

regulatory period, is at odds with that of all other regulators who have adopted the longest dated nominal bond, namely the 10-year bond as the appropriate bond.

Table 1: Bond rate maturity and averaging – recent electricity and gas decisions

Regulator	Decision	Date	Industry	Bond rate
ACCC	SPI Powernet	2002	Electricity (T)	5-year, 10-day average
ACCC	ElectraNet	2002	Electricity (T)	5-year, 10-day average
ACCC	Powerlink	2001	Electricity (T)	5-year, 40-day average
ACCC	SMHEA	2001	Electricity (T)	5-year, 40-day average
ACCC	Transgrid	2000	Electricity (T)	10-year, 40 day average
QCA	Qld DBs	2001	Electricity (D)	10-year, 20-day average
ORG	Vic DBs	2000	Electricity (D)	10-year, indexed 20-day average
IPART	NSW DBs	1999	Electricity (D)	10-year, 20-day average
OTTER	Aurora/Transend	1999	Electricity (D)	10-year, 12-month average
ICRC	Actew/AGL	1999	Electricity (D)	10-year, 20-day average
ACCC	ABDP (NT Gas)	2002	Gas (T)	5-year, 40-day average
ACCC	GasNet	2002	Gas (T)	5-year, 40 day average
ACCC	Moomba-Adelaide	2001	Gas (T)	5-year, 40 day average
ACCC	CWP	2001	Gas (T)	5-year, 40-day average
ICRC	Actew/AGL	2000	Gas (D)	10-year, 20-day average
IPART	AGLGN	2000	Gas (D)	10-year, 20-day average
OFFGAR	Dampier Bunbury	2001	Gas (T)	10-year, 20-day average
OFFGAR	Goldfields	2001	Gas (T)	10-year, 20-day average
OFFGAR	Mid West South West	2000	Gas (D)	10-year, 20-day average
ESC	Victorian gas	2002	Gas (D)	10-year, 20-day average
ORG	Victorian gas	1998	Gas (D)	10-year, 2-month average
QCA	Allgas, Envestra	2001	Gas (D)	10-year, 20-day average
SAIPAR	Envestra	2001	Gas (D)	10-year

2.1.1 Paper by Associate Professor Lally

The ACCC recently commissioned a paper from Associate Professor Martin Lally[3] who argued that the ACCC's approach to the risk free rate was correct.

Associate Professor Lally reached his conclusions from developing a regulatory model under which "the only source of uncertainty is in future real interest rates."[4] In this model, it is optimal for the business to finance its debt based on maturity equivalent to the duration of the regulatory period, given that by structuring its debt on this basis, the *ex-ante* value of future cashflows to the business matches the initial capital investment.[5]

In his example, because the optimal setting of debt maturity for the regulated company is to align with the regulatory cycle, it is appropriate for the regulator to set the maturity of the risk free rate in the CAPM and WACC to align with the regulatory cycle. It is important to note that it is the interest rate certainty over the period that drives the optimal decision on maturity of debt for the company, not the amount of the rate or how the rate is set.

However, the regulated environment described by Associate Professor Lally is extreme. Although he makes no attempt to relate his set of assumptions to an actual regulatory environment, at best it would be consistent with very strict rate of return regulation – in that businesses exactly earn the WACC set by the regulator. This is due to his assumptions that:

- output that will be sold is known with certainty;
- there is no uncertainty over operating costs;

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3 M. Lally, Determining the risk free rate for regulated companies, prepared for the Australian Competition and Consumer Commission, August 2002.

4 Ibid, p5.

5 For this result to hold there must be an upward sloping yield curve and minimal transactions costs of refinancing debt at each regulatory period. If these costs are large, the optimal refinancing period may change (be lengthened) even with Lally's other assumptions.

- there is no regulatory risk;[6] and
- the only risk facing the business is the impact of interest rate fluctuations on output prices.

However, his assumed regulatory arrangements ensure that the regulated entity is not exposed to interest rate risk given that changes in interest rates are used to adjust final product prices, ensuring that the business earns exactly the WACC.

It is important to note that Associate Professor Lally's results will generally not hold if his key assumptions are relaxed to be more in accord with the real world.

Where final demand is uncertain or operating costs can vary it can no longer be concluded that the *ex-ante* returns to the business will equal *ex-post* returns with certainty simply by structuring debt to mature at the expiry of the regulatory period. If uncertainty over costs and regulatory risk is introduced his results do not hold. To highlight this issue, consider regulatory risk – it is apparent that no regulatory system in Australia is capable of delivering the regulatory certainty assumed by Associate Professor Lally.

As Associate Professor Lally's results will then not hold by definition, the question becomes one of determining which bond maturity should best be used in setting the appropriate regulatory WACC.

Regulatory decisions should not change commercial decision making which would otherwise be efficient and socially desirable outcomes in an unregulated environment – rather, regulatory decisions should be consistent with those outcomes. Accordingly, regulatory decisions should not distort financing decisions away from those that would otherwise be most efficient. Assuming that a company can have a lower cost of capital by structuring its debt based on a bond maturity approximating the regulatory period implies that there are arbitrage opportunities available with regulated businesses that do not structure debt in such a way.

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6 Associate Professor Lally does not state this assumption, but it is necessary to his analysis. The regulated firm must have certainty that the regulatory regime will be stable for the life of the assets.

This seems unlikely and analogous situations can be drawn from other markets. Consider the case of an electricity generator, who is faced with a decision whether or not to use contracts to cover their exposure to the electricity spot market. The generator could either sell at the spot rate or buy some insurance and sell on a long-term basis. In equilibrium, the value of these options should be equal. The company could not 'save' by substituting one of these options relative to the other, assuming the markets in which their relative prices are determined are efficient.

Moreover, for a business such as an electricity generator, price sensitivity or the frequency of re-set bears no necessary correspondence to financing structures for such capital intensive assets, notwithstanding the fact that there is no doubt that interest rates over time will, for example, affect bids into the market.

In this light the view expressed by Associate Professor Lally and the ACCC - that setting the bond rate on the length of the review period can lower the cost of capital to the business - is unrealistic. If regular (5-yearly) reviews, for example, lowers the cost of capital relative to for example 10 yearly reviews, then the logical conclusion has to be that the cost of capital should be set daily based on the overnight rate. Indeed, in our view, more frequent regulatory reviews do not lower the cost of capital – the real impact of more frequent regulatory reviews is to increase the cost of capital on account of increased regulatory risk. In other words, the impact of more frequent reviews on the WACC for a regulated business is in precisely the opposite direction suggested by Associate Professor Lally.

A similar claim to that of Associate Professor Lally has been made by the ACCC, where in its Powerlink decision it noted:

> given that investors review investments over short periods, a shorter-term bond rate is the appropriate measure of the risk free rate.[7]

What is ignored by this view is that the regular reviewing of investment does not alter the fact that the asset in question is long-term in nature. It is the investment in long-term assets that is being remunerated by the regulatory rate of return. As noted by Hathaway:

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7 ACCC, Draft Decision, Queensland Transmission Network Revenue Cap 2002-06/07, July 2001, p. 13.

> Imagine you were running a 10-year bond portfolio and every 30 days you valued that portfolio. You would go to the market and use the prevailing 10-year bond rate. You certainly would not use the prevailing short rate to value that bond portfolio. So the interest rate you use has got nothing to do with the review period; the rate you use is the rate consistent with the life of the asset and particularly the risk in your equity risk premium. Anything else gives you an inconsistency.[8]

Moreover, applying Associate Professor Lally's approach will distort economic and commercial decision making leading to losses in productive and allocative efficiency. Consider for example the trade-offs between operating and capital expenditure - suppose that the regulated transmission business is considering undertaking capital expenditure on an asset with a life of 10 years, which is expected to reduce operating costs over that same 10-year period. Assume also that the regulatory period is one year.

If the investment decision is based on the one-year bond, then there will be stronger incentives to invest in the capital asset (and disincentives to undertake operating expenditure) than would be the case if the ten-year bond is used in the discount rate. This would distort the investment decision compared to the unregulated environment – where the company would base its decision on its (higher) cost of capital. This implies that a regulated business can base its investment decisions on a lower cost of capital than unregulated businesses. However, irrespective of regulatory practice, a firm's cost of capital remains the opportunity cost associated with investments in long term assets and its decision making will be determined accordingly. In other words, if a regulator adopts a WACC below the regulated businesses' cost of capital, the result will be that the regulated business will simply not undertake socially desirable investments. Short term gains for consumers from lower prices will be quickly consumed by higher costs from congestion that is suffered through a lack of investment.

Associate Professor Lally's arguments also ignore the point that equity – for which the return under the CAPM is derived using the risk free rate - cannot be hedged. Equity remains a residual risk irrespective of the debt arrangements, and the risk to equity holders cannot be

8 N. Hathaway, Transcript of Public Forum held by ACCC and ORG on the Weighted Average Cost of Capital in the Victorian Gas Access Arrangements, 3 July 1998, p80.

hedged against in the way suggested by Lally for debt. In practice, this is particularly important for companies such as Transend, which exhibits low levels of gearing.

Additionally, Associate Professor Lally's model fails to consider the full nature of the CPI adjustment that forms an essential component in any revenue cap arrangement (and indeed in any regulatory arrangement). Not only is there a revisiting of prices annually on account of unders and overs provisions under a revenue cap, but more importantly the CPI adjustment provides an imperfect hedge against a range of movements, including inflation. Even leaving aside time lags in applying inflation to regulated prices, inflationary expectations are not fully reflected in interest rates such that the CPI adjustment does not provide a perfect hedge against the inflationary expectation component in the interest rates.

That is, regulated businesses face an inflation risk that is not addressed in Associate Professor Lally's model. Assume a regulated business secures debt funding as suggested by Associate Professor Lally – the interest rate at the time of the decision will be based on inflationary expectations. The CPI adjustment compensates the regulated business for actual inflation. Hence the existence of an inflation risk that is not recognised in Associate Professor Lally's model. Moreover, inflation adjustments are undertaken on an annual basis rather than length of the regulatory period highlighting the gap between Associate Professor Lally's model and established regulatory practice.

In all these examples, the appropriate policy for the business is to match duration with the life of the major asset. This policy holds even where the regulator chooses to adopt a different approach and set the bond rate based on the length of the regulatory period– unless the presence of the regulator provides arbitrage opportunities that do not exist in unregulated markets.

Finally, contrary to the hypothetical regulatory environment illustrated by Associate Professor Lally, regulatory risk is a fact of life in most regulatory frameworks – a point widely accepted by regulators in Australia and stated in the recent Productivity Commission report on the National Access Regime:

> In seeking to reduce access prices that are inefficiently high, the ACCC must have regard to the following principles: (a) that the access prices…(ii) include a return on investment commensurate with the regulatory and commercial risks involved.[9]

Given that there may be a large number of regulatory reviews and changes in regulators over the life of an asset, an investor cannot be confident that the regulatory framework will be unchanging. Even if all of Associate Professor Lally's other assumptions are met, as the regulatory uncertainty increases, the business will be less willing to structure its debt based on the regulatory period and will rationally revert to standard commercial practice of matching debt maturity with asset life.

In its GasNet draft decision the ACCC relied on an argument similar to that adopted by Associate Professor Lally where it stated:

> In accordance with these requirements, the Commission considers that it is appropriate to maintain the use of interest rates that correspond with the length of the access arrangement period. Thus, for GasNet, which is seeking a five year access arrangement period, the yield on bonds with a term to maturity of five years should be used. The adoption of this methodology should ensure that the expected regulatory return over the sequence of reviews will match the initial risk-free rate expected by the market over the life of the asset. This approach should provide GasNet with the right signals for investment at all times.

Similarly in its Powerlink decision the ACCC noted:

> ..the use of such bond yields will ensure that rates that asset owners are expected to be subject to through the course of the regulatory period will exactly correspond with estimated rates.[10]

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9 Productivity Commission, Review of the National Access Regime, Inquiry Report No17, September 2002, p332.

10 ACCC, Final Decision, Queensland Transmission Network Revenue Cap 2002-06/07, November 2001, p. 15.

However, both conclusions can only be reached under the restrictive assumptions adopted by Associate Professor Lally.

No regulatory environment in Australia corresponds to that described by Associate Professor Lally. Once we enter a world where investment in long-term assets is not a riskless activity it is critical to consider the opportunity cost of the investment and the fact that investors are financing a long-term investment for which the majority of the value is in future regulatory periods. In such an environment it is best to adopt the standard commercial practice of matching the term of risk free rate with the life of the asset – after all this is the most important economic decision being driven by the choice of the risk free rate. By suggesting that businesses should shift away from standard business practice may have important implications for investment, particularly if it shifts the focus away from long term investment, a point noted by the Productivity Commission:

> "Given that precision is not possible, access arrangements should encourage regulators to lean more towards facilitating investment than short term consumption of services when setting terms and conditions."[11]

2.1.2 Other arguments in support of the ACCC position

Appropriate for one-period nature of CAPM

The ACCC has previously argued that adoption of a maturity consistent with the regulatory period is appropriate for the CAPM given it is a one period model that is revisited each regulatory review. By capturing future revenues in a terminal value, CAPM can be made to be a single period regulatory model. In its Powerlink decision, the ACCC noted:

> the use of yields commensurate with the regulatory period is appropriate under the CAPM framework. The CAPM is a one period model and thus theoretically

11 Productivity Commission (2001), *Review of the National Access Regime*, Position Paper, Canberra, March, page XXII.

> more appropriate to estimate the rate for one regulatory period, rather than over the course of numerous regulatory periods.[12]

However, while CAPM is a single period model, there is no guidance on the appropriate length of that one period. In reality, the majority of the net present value (NPV) of a regulated business such as an electricity business with asset life of up to 40 years is in future regulatory periods.

Not necessary to have consistency in the CAPM

In his paper written for the ACCC, Associate Professor Lally claims that it is perfectly reasonable for the risk free rate to be set on a different basis to other variables in the CAPM, notably the market risk premium. He concludes:

> Thus the claim that the risk free rate used to determine the market risk premium must be consistently applied throughout the CAPM valuation formula is false.[13]

However, such a model is clearly not the CAPM as can be illustrated with a simple example.

As set out in the introduction, the CAPM is generally written as follows:

$$E(Re) = Rf + b^* [E(Rm) - Rf]$$

where

Re	=	cost of equity capital;
Rf	=	risk free rate of return;
Rm	=	market rate of return;
E(.)	=	indicates the variable is an expectation; and
b	=	systematic risk parameter ("beta").

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12 Ibid.

13 Ibid, p12.

If we apply the CAPM for a company that has a beta of one we find:

$$E(Re) = Rf + 1 * [E(Rm) - Rf] = E(Rm) + [Rf - Rf]$$

Since the company has the same beta as the market, it must be that - E(Re) = E(Rm). But this can only be the case if [Rf - Rf] = 0, which of course implies that Rf = Rf – namely the risk free rate applied to estimating the market risk premium must be the same risk free rate as used in determining the base risk free rate.

If R_f is not the same in both places that it appears in the CAPM, then a firm with a beta of one would not have the same expected return as the market. More pointedly, if Rf is not the same in both instances, the model being used is not the CAPM.

2.2 Period of averaging

As can be seen in table 1, the ACCC has traditionally adopted a forty-day average of rates immediately preceding the date of the setting of the risk free rate. However, in its SPI Powernet and ElectraNet decisions, the ACCC reverted to using a 10-day moving average having flagged the possibility of a 5-day moving average in the SPI Powernet draft decision.

Consistent with the ACCC's SPI and ElectraNet decisions we have adopted a 10-day averaging period. As of 4 February 2003, the 10-day average of the 10-year Commonwealth bond was 5.24%.

2.3 Inflation

While not a direct parameter in setting a vanilla WACC, the inflation rate is implicit in the value of the risk free rate and cost of debt. There are two main sources of data for inflation: information in the financial markets and government (or other) estimates.

The first method involves considering yields on nominal and capital indexed government bonds of similar maturity. By using the Fisher equation, an estimate of inflation can be determined.[14] The alternative approach is to refer to inflation forecasts of the major market participants such as the Reserve Bank of Australia.

NECG supports the use of the first approach for two main reasons:

- by considering the yield on nominal and capital indexed bonds, an inflation forecast consistent with the CAPM parameters can be determined; and
- the inflation forecasts issued by organisations such as the RBA are by their nature short term in nature, and may only reflect expectations for a one-year period.

The current yield on an index linked Commonwealth bond of 10-year maturity can be approximated by the average of the yield of bonds maturing in August 2010 and August 2015. For the 10 day period ending on 4 February 2003 this average was 3.23%. Using a nominal risk free rate of 5.24% and the Fisher equation produces an estimate of inflation of 1.95%.

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[14] The fisher equation estimates inflation as (1+ nominal bond yield)/(1+ indexed bond yield)-1.

3 Market risk premium

The market risk premium (MRP) is the amount an investor expects to earn from an investment in the market above the return earned on a risk-free investment. The key difficulty in estimating the MRP arises from it being an expectation and therefore not being directly observable. As a result the choice of an appropriate rate is inevitably *ad hoc*. Generally a range of plausible values is identified and the MRP is chosen within the range, most commonly at the midpoint.

In determining the appropriate MRP to apply, we consider:

- use of historical data to generate a range; and
- the assessment of an appropriate point in that range.

3.1 Historic evidence

In assessing historical evidence, the generally accepted range among corporate finance professionals in Australia has been 6% to 8%.[15] This range is largely favoured because of empirical evidence of the historical, realised MRP in Australia dating as far back as 1882. In the absence of additional evidence, the midpoint of 7% was often picked as the point estimate. In 1999, Davis presented a range for MRP of between 5% and 8%, and noted that the midpoint of 6.5% "is not unreasonable."[16] Section 3.2 of Schedule 6.1 of the National Electricity Code also notes that the MRP has averaged 6.6% since 1952.

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15 For example, see R. Officer, "Rates of Return to Shares, Bond Yields and Inflation Rates: An Historical Perspective," in *Share Markets and Portfolio Theory*, 2nd ed, 1989 University of Queensland Press, St Lucia, 1989, pp. 207-11.

16 K. Davis, "Comments on the Cost of Capital: A Report prepared for the ACCC," April 1999.

Recently, Dimson, Marsh and Staunton[17] undertook a comprehensive study of financial market performance for sixteen countries from the end of the nineteenth century to the beginning of the twenty-first, finding that the MRP for the Australian economy was 7.0% over this period. The authors noted that the better performing equity markets were those of resource rich economies such as Australia.

Historical estimates of MRP are given in Table 2.

Table 2: Historical estimates of MRP

Source	Market risk premium (%)
Officer (1989) (based on 1882-1987)[18]	7.9
Hathaway (1996) (based on 1882-1991)[19]	7.7
Hathaway (1996) (based on 1947-91)[20]	6.6
NEC (based on 1952-99)[21]	6.6
AGSM (based on 1964-95, including October 1987)[22]	6.2
AGSM (based on 1964-95, excluding October 1987)[23]	8.1
Dimson, Marsh, Staunton (2002) (based on 1900-2000)[24]	7.0

17 Dimson E, Marsh P, Staunton M, "Triumph of the Optimists: 101 Years of Global Investment Returns", Princeton University Press 2002.

18 R. Officer, op cit, pp. 207-11.

19 N. Hathaway, "Market Risk Premia", unpublished manuscript.

20 Ibid.

21 National Electricity Code, schedule 6.1, section 3.2.

22 IPART, "Regulation of New South Wales Electricity Distribution Networks," section 5.4.2, Table 5.4, December 1999.

23 Ibid.

The historic data set out above is consistent with a range of 6.0% to 8.0%.

3.2 Appropriate point within the range

In response to a belief that the MRP has declined in recent years, most regulators have adopted a figure at the bottom end of this range – namely 6%. The ACCC has adopted this practice. In a recent study Associate Professor Lally noted:

> To summarise this review of evidence on the market risk premium in the Officer CAPM, the estimates are .07 from historical averaging of the Ibbotson type, .056 from historical averaging of the Siegel type, .07 from the Merton methodology, and .040-.057 from the forward-looking approach. If a point estimate for the last approach is .048, then the average across these four approaches is .061. In addition various other methodologies have been alluded to, for which Australian results are not available but which have generated low values in the markets to which they have been employed. All of this suggests that the ACCC's currently employed estimate of .06 is reasonable, and no change is recommended.[25]

Associate Professor Lally sets out four alternative approaches to estimating the MRP and discusses them in his report. He does not explain why he chose to ignore other approaches that could be used.[26] Furthermore, he then averages across what are four fundamentally different approaches to support his position that an MRP of 6% is reasonable. Such an averaging cannot be supported, particularly not the averaging of historical estimates with forward looking estimates.

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24 Op cit.

25 Lally, M, The Cost of Capital under Dividend Imputation, a report for the ACCC, June 2002, p34.

26 Such as a benchmarking approach to determining the MRP.

Rather than an analysis of all the approaches he considers, we will focus on his forward-looking estimates of MRP. In principle, we regard the forward looking approach as valid, however the estimates are only as good as the models and data used. In our view, the models being used to make forward-looking estimates of MRP are still crude and should be used with caution. More importantly here, the estimates cited by Associate Professor Lally are likely to understate the MRP given that almost all the estimates considered are based on data during the bull market, which is unlikely to provide a valid basis for estimating a forward-looking MRP at the current time.

If the forward looking estimates are discarded as being based on inadequate models with data that is inherently biased, an average of Associate Professor Lally's other estimates produces a value closer to 7.0% - the mid point of the range of historical estimates.

In considering the appropriate point for the MRP within this historical range, we will consider the following issues:

- recent (short term) estimates of the MRP;
- benchmarking approaches to MRP; and
- the relevance of surveys of MRP at the present time.

3.2.1 Recent estimates of MRP

A number of regulators have justified adopting a MRP at the bottom end of the historical range based on evidence of recent reductions in the ex-post MRP. However, given the need for data of significant duration (at least 30 years) to provide statistically robust results, such data should be treated with care, particularly given recent volatility in the MRP. The ACCC may have considered this point in its SPI Powernet decision where it notes:

> The Commission recognises that the market risk premium has fallen over recent years, however the Commission is wary that this may reflect short term market trends.[27]

While we agree with the thrust of the ACCC's comment – and note that over the past two years the (short term) MRP has increased significantly, the ACCC's position of adopting a value of 6% is still inconsistent with long-term market trends. Indeed, to the extent that consideration is given to historical averages, it is difficult to depart from an assumed market risk premium of 7%.

3.2.2 Benchmarking approach to MRP

An alternative way of setting a MRP is through a benchmarking approach. Australia is an open economy. Investment funds move freely into and out of the country and the currency. As of September 2000 non-resident investors owned 37.5% of the value of the Australian Stock Exchange, the largest single shareholder group by far. In addition, as of 31 March 2002, non-residents held over 33% of all Commonwealth government securities.[28]

The Australian debt and equity markets have only been integrated into world markets for around 20 years. Prior to deregulation, market prices (and in turn the MRP) were significantly affected by government intervention, in particular the restrictions on foreign ownership of shares and exchange rate controls. This resulted in prices of shares and government bonds being predominantly determined by domestic (rather than international) factors. Given these circumstances, it is unlikely that the *ex post* MRP in this market provides the best estimate of an *ex ante* MRP in the current (international) market.

In the absence of sufficient relevant historical information from the current market, an alternative approach to estimating the MRP is through a benchmarking approach. With this approach, a benchmark country is chosen based upon it having a reliable estimate of MRP.

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27 ACCC, Victorian Transmission Network Revenue Caps 2003-2008, Final Decision, December 2002, p27.

28 Reserve Bank of Australia, "Bulletin Statistical Tables," http://www.rba.gov.au/Statistics/Bulletin/EO3hist.xls

Then the potential differences between the MRP in that country and the MRP in Australia are evaluated. These could include taxation, country risk, estimation time horizon and market composition differences.

Bowman recently estimated the Australian MRP from the US MRP using a benchmarking approach to be 7.8% on the basis of:[29]

- a US MRP in the range of 6.0 to 9.0%; and
- an increment of 0.1% to 2.35% on the US MRP for differences in taxation, market composition, country risk and estimation time horizon between the US and Australia, with 0.3% considered an appropriate adjustment.

Similarly, Ibbotson Associates suggest that the US market risk premium is 7.76% and that based on Australia's country credit rating, the expected return on the Australian market is 1.53% to 2.26% higher than for the U.S.[30]

This benchmarking approach suggests that a figure at least at the upper end of the 6.0 to 8.0% range would be appropriate for Australia.

3.2.3 Survey data

ESC and IPART have recently made reference to a number of survey studies of MRP. These include:

- two studies by Welch[31,32] – who surveyed academics finding MRP of 7.1% and 5.5% respectively;

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29 R. Bowman "Estimating the Market Risk Premium," *JASSA*, Spring 2001, pp10-14. However, We understand that Professor Bowman has since revised his benchmarked estimate of the market risk premium in Australia to 7%.

30 Ibbotson Associates, (2001), "International Cost of Capital Report 2001," valuation.ibbotson.com.

- Graham & Harvey[33] – who surveyed 1107 CFO's between 2000 and 2001, resulting in a range for the MRP of 3.6-4.7%;
- Mercer Investment consulting[34] – who surveyed brokers finding a range of 3.0-6.0%, noting that in its own advice it adopts a figure of 3.0%; and
- Jardine Fleming Capital Markets – who surveyed 61 respondents in Australia, of which 35 were non-academics, finding an average expected MRP in Australia of 4.73%.

On face value, surveys have a substantial advantage over historical estimates of MRP. Properly constructed, they should provide actual forward-looking opinions. However, there are a number of critical dimensions to their validity:

- the nature of the participants in the survey;
- the biases the participants may have with respect to the issue being surveyed; and
- the time horizon the participants may considered.

Considering each of the studies against these dimensions raises a number of critical flaws.

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31 Welch, I., 2000, "Views of Financial Economists on the Equity Premium and other Issues," The Journal of Business 73(4), 501-537.

32 Welch, I., 2001, "The Equity Premium Consensus Forecast Revisited," Working Paper, Yale University.

33 Graham, J., C. Harvey, 2001, "Expectations of Equity Risk Premia, Volatility and Asymmetry from a Corporate Finance Perspective", working paper, Duke University.

34 Mercer Investment Consulting, Victorian Essential Services Commission Australian Equity Risk Premium, 1 July 2002.

Welch surveys

The surveys by Ivo Welch were to be based upon views of the US markets. The intention of the first survey was that the participants would be professional financial economists, primarily academics. The second survey was "by invitation" and was restricted to professors of finance and economics.

A key concern with the findings of Welch's surveys is the role that Welch himself took. His first survey was open to everyone who visited his website, the second survey was by invitation only. Welch disclosed that the results of the first survey were higher than his personal view, which casts doubt on the validity of the results of the second survey. Accordingly, it is thought that the first survey provides an inherently more credible estimate of the MRP and therefore ought to be preferred.

Graham and Harvey

Graham and Harvey surveyed CFOs in the US on their estimates of the forward-looking MRP at various horizons. They found that:

> "the one-year risk premium is highly variable through time and 10-year expected risk premium is stable. In particular, after periods of negative returns, CFOs significantly reduce their one-year market forecasts, disagreement (volatility) increases and returns distributions are more skewed to the left (i.e., low). We also examine the relation between ex ante returns and ex ante volatility. The relation between the one-year expected risk premium and expected risk is negative. However, our research points to the importance of horizon. We find a significantly positive relation between expected return and expected risk at the 10-year horizon." (taken from the abstract).

While CFOs of large corporations might be expected to be familiar with the issue being surveyed, the results of the survey are not internally consistent and in some respects are contrary to a fundamental principle of economics that expected risk and expected return are positively related. At the one-year horizon, these CFOs believe that risk and return are negatively correlated. Although the survey does not shed light on this anomalous belief, we presume that it results from their focus being excessively short term and influenced by recent historical outcomes. Clearly this survey has little credibility as a basis for estimating a MRP.

Mercer

Mercer Investment Consulting surveyed brokers. While it can be argued that these people would be both knowledgeable and interested in the topic, there are a number of concerns in basing MRP estimates on the views of brokers:

- they are not likely to be particularly knowledgeable of the theoretical and empirical research on the issue; and
- their assessments, which are intended to be forward-looking, are strongly correlated with the recent past but have no predictive power.

Jardine Fleming Capital Markets

The results of the Jardine Fleming survey do not appear to match with the risk profile of the Australian and US equity markets. The survey makes two unusual conclusions: firstly that past MRP was higher in the US than Australia by about 40 basis points; and secondly that the expected MRP in Australia is about equal to that in the US. For these to be true, Australia's equities would have to be no less risky than equities in the US. This seems unlikely. For example in its PSTN decision, the ACCC stated that the Australian market is "... a higher risk, more resource-based, economy [than the UK economy]".[35] Given that the UK market would not be expected to be any less risky than the US, then it follows that the Australian market is riskier than that of the US.

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35 Australian Competition Consumer Commission, "A report on the assessment of Telstra Corporation Limited, Undertaking for the Domestic PSTN Originating and Terminating Access services", July 2000

Conclusion on surveys

In general, surveys are interesting, but they may tell us more about the people being surveyed than about the issues being surveyed. As a result, the biases created reduce the validity as an appropriate estimator of a forward-looking MRP.

3.3 Conclusion on MRP

Whilst we know that the MRP varies over time, accurately quantifying this variation is impossible in practice. Indeed, the most recent data would suggest that the MRP has been increasing over the past year in ex post terms, although for the reasons outlined above, we believe the critical issue is the long term average for the assessment of the MRP.

As noted above, the historical range for the MRP favoured by finance professionals has been 6.0 to 8.0%. Evidence suggesting short term declines in MRP does not provide valid support for policy setting. Evidence on benchmarking approaches to the MRP also suggests a figure at the high end of the range may be appropriate. Such findings are consistent with the recent findings of Dimson, Marsh and Staunton noted earlier, who found that the MRP for the Australian economy was 7.0% over the last century.

It is also important that the estimation of the MRP is on a basis consistent with the bond maturity used to set the risk free rate. If the ACCC is to continue its current practice of using the 5-year bond for the risk free rate (which we advise against), it needs to devise a methodology for adjusting the market risk premium to have a consistent maturity. An approach would be to calculate the average spread between the 5-year and 10-year bond yields and adjust the MRP, that is based on a 10-year maturity, for this spread. A difficulty with this approach is that we are not aware of a data base of the yields on the bonds that would span the period(s) used to estimate the MRP. The Reserve Bank of Australia has data on its website that would allow calculating the spread from 1993 to the present. Under that circumstance, this is likely to be a reasonable estimation.

NECG's view is that the MRP lies in the range between 6% and 8%. For regulatory purposes, adopting the mid-point of 7% is the most appropriate approach for estimating the MRP. However, NECG recognises Transend's desire to take account of regulatory precedent in estimating its cost of capital. On this basis, NECG's advice is that the ACCC is likely to confirm its previous regulatory decisions that 6% is an appropriate estimate of the MRP. Notwithstanding current regulatory practice, however, NECG's view is that substantially higher estimates of MRP could be justified.

4 Debt

The cost of debt capital for a company will be related to market rates of interest on debt, the appropriate maturity of debt, the assumed capital structure and the company's credit rating.

A number of relevant issues in relation to debt are discussed below.

4.1 Capital structure

Standard regulatory practice by the ACCC and other regulators in all energy decisions has been to assume a benchmark gearing of 60%. In doing so, the ACCC has argued that this value is within a range where the cost of capital is stable, is consistent with market practice and consistent with the approach of other regulators.

Currently, Transend has little debt and hence low gearing. To assume that gearing should be at a notional level of 60% implies that Transend currently has a sub-optimal capital structure, which can be disputed.

A company has an economic incentive to structure its capital optimally, as the value of the company is affected by capital structure. Given this fact and the wide range in gearing that is consistent with a stable cost of capital, we believe that the most appropriate stance is for the regulator to assume that the company's actual gearing is efficient, and that this should only be altered for pricing purposes if it can be demonstrated by the regulator that actual gearing is not efficient.

In the event that a regulator decides to assume a gearing other than what is employed by the company, it is important that all other variables in the WACC are assessed on the basis of the assumed gearing, not the actual gearing. This will mean adjustments to the cost of debt and the equity beta.

4.2 Debt margin

Table 3 sets out the debt margin provided in regulatory decisions over the recent past.

Table 3: Debt margin allowed in recent regulatory decisions

Date	Regulator	Business	Margin (bp)	Notes (if any)
Dec-02	ACCC	SPI Powernet	120	Considered firm with "A" credit rating would require margin of 120 basis points for 5 year borrowing.
Dec-02	ACCC	ElectraNet	122	Based on "A" credit rating – 111 basis points plus 10.5 for debt issuance.
Dec-02	ACCC	NT Gas/ABDP	154	40 day average of corporate issue rates for BBB+ debt
Nov-02	ACCC	GasNet	158.5	Based on corporate issue rates for (benchmark) BBB+ rating. Includes 12.5 basis points for debt raising costs
Oct-02	ESC	Vic gas distributors	170	Estimate of market cost of raising debt based on BBB+ rating. Includes 5 basis points for establishment costs
Nov-01	ACCC	Powerlink	120	Not stated
Nov-01	QCA	Gladstone Area Water Board (draft)	180	Estimate of market based cost of raising debt based on BBB rating
Oct-01	QCA	Qld gas distribution	155	Estimate of market based cost of raising debt based on BBB+ rating

While this is a relatively limited sample, these decisions have resulted in the following ranges being set for the debt margins (excluding any transactions costs):

- for BBB credit rating a debt premium of 180 basis points;
- for BBB+ credit rating a debt premium of 130-165 basis points; and
- for A credit rating a debt premium of around 120 basis points.

In its most recent electricity and gas decisions the ACCC has determined a benchmark credit rating for the company in question based on the credit rating of listed entities operating in the same sector. Current Standard & Poors ratings of major energy businesses are set out in Table 4.

Table 4: Credit rating of major energy utility businesses (October 2002)

Company	Rating	Gearing	Sector
AGL	A	36%	Electricity and gas distribution
United Energy	A-	46%	Electricity and gas distribution
ElectraNet	BBB+	Above 60%	Electricity transmission
Origin Energy	BBB+	29%	Gas transmission and electricity retailing
Envestra	BBB	74%	Gas distribution
GasNet	BBB	69%	Gas transmission

Source: Standard and Poors Australian Report Card: Utilities, 29 October 2002. Gearing from ACCC GasNet decision (Envestra, GasNet), ESC Victorian gas decision (AGL, United Energy), Financial statements (Origin Energy) and regulatory submission to ACCC (ElectraNet). SPI Powernet (A+), ETSA Utilities (A-), Powercor (A-) and TXU (BBB) have all been excluded from this table as their rating primarily reflects the rating of the major controlling shareholder.

It can be seen from Table 4 that the three comparators that have a gearing at or above the ACCC's benchmark level (60%) have credit rating of either BBB or BBB+. Similarly, the companies with ratings above BBB+, namely AGL and United Energy both have gearing well below 60%. While a number of factors go into determining a company's credit rating, this data suggests that adopting a credit rating of BBB+ for a utility company with benchmark gearing of 60% may not be inconsistent with market observations.

In applying a benchmark gearing to Transend, a number of factors need to be borne in mind – notably its small size and reliance on a few large customers for its revenue – both which will impact adversely on its credit rating. As a result, a credit rating of BBB+ is unlikely to overstate the rating that Transend would receive if geared at 60% debt.

Data from CBA Spectrum[36] suggests that an appropriate debt margin for credit rating BBB is 132 basis points, based on an averaging period consistent with that of the risk free rate.

4.3 Transactions costs

In order to adhere to the principle of financial capital maintenance, it is necessary that regulated businesses be compensated for:

- all transactions costs associated with the raising of debt and equity; and
- all hedging costs associated with securing a position in the market that removes financial risk associated with the regulatory process.

In its recent decision on GasNet, the ACCC accepted the validity of including allowance for the transaction costs of raising debt and equity finance. In doing so, it recognised bank fees and dealer swap margins as legitimate debt raising costs; and costs paid to equity arrangers for services such as structuring the issue, preparing and distributing information and undertaking presentations to prospective investors as legitimate costs of raising equity.[37] In its recent decision on Victorian gas distributors, the ESC also accepted the validity of including an allowance for non-margin establishment costs in the cost of debt.

Transend would incur significant debt financing costs if it were to shift from its current gearing to one approximating the ACCC's benchmark rate of 60%. We estimate that if the same debt issuance assumptions that were applied for GasNet are adopted to Transend then

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36 www.cbaspectrum.com.

37 At a recent forum on the cost of capital (24 June 2002), Westpac Corporate Finance estimated the following premiums required. These included CPI swap costs (10-20 basis points), Volume premiums (10+ basis points), New product premiums (20+ basis points) and Term premiums (10-20 basis points).

a figure at least as high as for GasNet would result. Consistent with the ACCC's GasNet decision, we have increased the debt margin for Transend by 12.5 basis points.[38]

This results in a total debt margin of 144.5 basis points.

4.4 Debt beta

The key role for the debt beta is in the de-levering and re-levering of equity betas in the CAPM. When we convert between asset betas and equity betas, we are converting measures of systematic risk for the effect of debt in the capital structure. 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 the systematic risk of debt. This justifies measuring the debt beta only in terms of the extent that the risk of debt varies systematically with the market. As the risk of debt is primarily related to default, a relatively low debt beta is appropriate. In order to be consistent with the ACCC's practice on this issue, we have adopted a debt beta of zero in the levering and de-levering of Transend's asset and equity beta.

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38 Note that US data suggest that a premium for debt issuance of up to 50 basis points may be appropriate. There, debt can be issued either directly by private placement or through a public issue. The issuance costs of a direct placement are considerably lower than a public issue. However, the interest rates paid on private placements are usually higher than those on a public issue. So there is a trade-off when issuing debt by private placement – issuance costs are lower but interest rates are higher. Brealey and Myers (ibid, p401) state that "a typical differential (between the interest rate on public and private issues) is on the order of 50 basis points". Hays, Joehnk and Melicher ("Determinants of Risk Premiums in the Public and Private Bond Market," *Journal of Financial Research*, Fall 1979) conducted an empirical study of the difference in rates between public and private debt issues and found that the yield to maturity on private placements was 0.46% higher than on similar public issues.

5 Beta and the cost of equity

The CAPM assumes all non-systematic risks are diversifiable and hence are not provided an expected return in a competitive market. The systematic risk (β or beta) of a firm is the only risk factor incorporated in the CAPM.

The assessment of systematic risk normally involves:

- assessment of the appropriate asset beta for Transend; and
- the appropriate measure of the equity beta based on the asset beta and the debt beta.

5.1 Asset beta

The asset beta represents the risk arising from the sensitivity of the operating cash flows generated by an entity's assets compared with the market in general, that is, the market risk associated with an entity's business. Asset betas vary with the volatility of free cash flows and are driven by the sensitivity of those cash flows to fluctuations in the economy.

Three sets of considerations have been applied in estimating an appropriate asset beta for Transend:

- an assessment of comparable companies in Australia and overseas;
- regulatory decisions; and
- an assessment of the factors that impact on the sensitivity of Transend's returns to movements in the economy.

This section considers these factors in turn, and concludes with a brief summary.

5.1.1 Assessment of comparable businesses

Given the lack of listed regulated businesses, regulators have often relied on the "method of similars" to estimate the asset beta of the regulated entity. Given that systematic risk is largely country specific, the most meaningful beta estimates can generally be derived using domestic comparators.

The most recent estimates of beta for the major listed Australian regulated energy businesses are set out in table 5.

Table 5: AGSM estimates of asset beta – June 2002 (debt beta = 0)

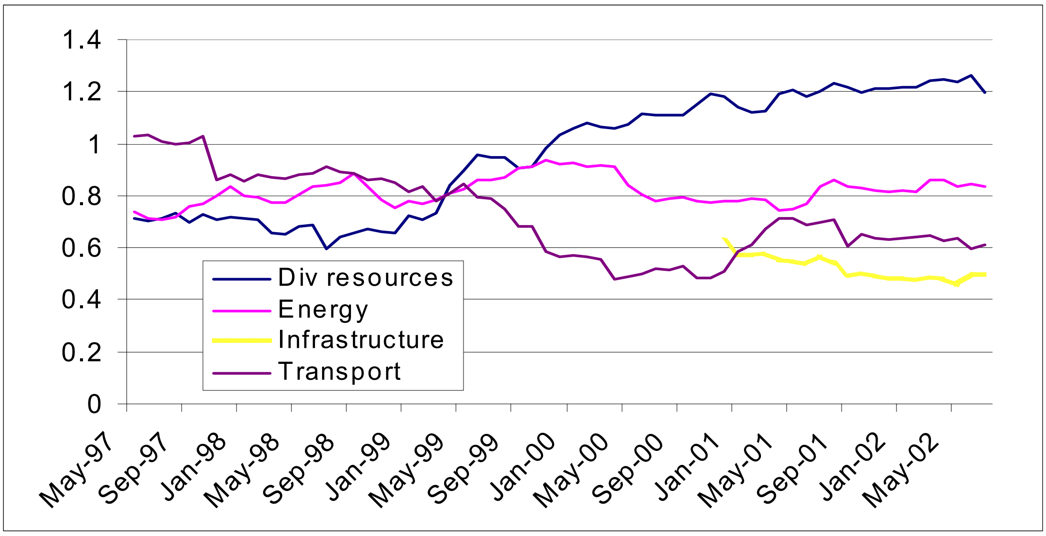
Company	Equity beta	Gearing	Asset beta
Australian Gas Light	0.36	36%	0.37
Envestra	0.59	74%	0.19
United Energy	0.25	46%	0.27

Source: AGSM Risk Management Service, June 2002. Alinta Gas has been excluded from this table due to a limited number of observations.

The data in this table must be treated with caution. Envestra has a highly unusual capital structure and still presents a significant risk of biasing beta estimation.[39] Similarly, caution is required in using the current beta measures of AGL and United Energy given that beta estimates exhibit considerable volatility, with the current estimates representing a low point by recent historical standards. Not only are there wide standard errors in the estimates, but the significant volatility in beta estimates cannot be hedged against. The average dispersion of betas is over 0.30, while the inherent volatility in beta measures can be seen in figure 1.

39 Note that as recently as September 2001, the QCA didn't consider Envestra in its comparison of listed entities when estimating a beta value for Envestra's regulated gas distribution activities.

Figure 1: Volatility in industry average betas over time



An alternative approach is to consider the asset betas of regulated energy companies listed in overseas markets. In doing so, the process followed was to search globally for statistically significant betas of publicly listed companies, using financial markets information from Bloomberg.

Over sixty electricity firms were sampled. The samples were large to enable an examination of indicative firms that had betas that were statistically significant. The down loaded firms were ranked on level of significance of the calculated equity beta based on monthly observations. Monthly observations were taken where possible as beta calculated over longer intervals helps to overcome the infrequency of trading problem.[40]

The returns were regressed on the returns of the appropriate market index. For example US firm returns were regressed on the S&P 500. Gearing data was also down loaded. The final

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40 Equity betas were calculated was using monthly data for a 60 month period. Where it was not possible to obtain 60 monthly observations, the differencing interval was shortened. For example if only one and one half years of data was available, weekly observations were used so that the beta could be calculated over 60 observations.

sample was reduced to 17 companies through a filtering process based on the similarity of the business operations and the statistical significance of the beta. Any beta with an associated t statistic less than 2 was ignored in the analysis. Raw betas were adjusted in accordance with the standard Blume adjustment.[41] De-levering was undertaken using the Monkhouse formula, consistent with the re-levering approach used by the ACCC and in this report.[42] This process resulted in the sample that is set out in Table 6, which includes data on both distribution and transmission companies.

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41 The Blume adjustment adds one-third to the raw equity beta multiplied by two-thirds and reflects the observation that betas tend to one over time. International studies supporting the use of adjusted betas include Sharpe, W.F., Alexander, G.J. and Bailey, J.V. (1995), *Investments*, 5th edition, Englewood Cliffs, Prentice Hall, Blume, M.E. (1971), 'On the Assessment of Risk', *Journal of Finance*, March pp. 1-10; and Blume, M.E. (1975), 'Betas and their Regression Tendencies', *Journal of Finance*, June, pp. 785-795.

42 Note that corporate tax rates were included rather than effective tax rates and for the international companies a gamma of zero was assumed. A constant cost of debt was assumed. While this assumption may not hold in practice, the results are robust and consistent with other approaches (Hamada/Brealey Myers) for ranges in the cost of debt far in excess of those that may apply in practice.

Table 6: Beta estimates of international energy network businesses (debt beta = 0)

Company	Country	Sector	Equity beta	Gearing	Asset beta (based on adjusted equity beta)
National Grid Transco SP-ADR	US	T	0.31	38%	0.34
National Grid Transco Plc	UK	T	0.46	38%	0.40
Red Electrica d'Espania	Spain	T	0.51	35%	0.44
Transener SA	Argentina	T	0.45	90%	0.06
Cia de Transmissao de Ene	Brazil	T	1.28	20%	0.95
Ak Energy	Turkey	D	0.82	19%	0.72
Aksu Energy	Turkey	D	0.82	0%	0.88
Ayen Energy	Turkey	D	0.88	72%	0.26
CGDE	Luxemburg	D	0.38	4%	0.56
Electopaulo Metropolitana	Brazil	D	1.01	77%	0.24
Demasz	Hungary	D	0.52	4%	0.65
Prazska Energetika	Czech	D	0.73	15%	0.70
Demasz	E Europe	D	0.55	0%	0.70
IFX Power	Britain	D	0.77	23%	0.65
CPFL	Brazil	D	0.48	57%	0.28
EMASZ	Hungary	D	0.36	0%	0.57
Horizon Energy	NZ	D	0.57	26%	0.53
Trust Power	NZ	D	0.52	25%	0.51
Florida Public Utilities Co.	US	D	0.32	58%	0.23
United Energy	Australia	D	0.52	46%	0.37
Average transmission			0.60	44%	0.44
Average distribution			0.62	30%	0.51
Average all companies			0.60	34%	0.49

This sample has an average asset beta, based on de-levered equity betas, of 0.49, with the average for the transmission entities being 0.44 and the distribution businesses 0.51.[43] Similar results are obtained if the analysis is restricted to OECD comparators.[44]

These estimates are on the whole significantly higher than those of the listed Australian entities (and in turn the Australian estimates are significantly lower than those of the same entities taken one or two years ago). We believe this highlights the need for caution in estimating betas for regulated entities, especially critical given the asymmetric consequences of regulatory error.

The results of the survey highlight that asset betas for businesses involved in electricity distribution are higher than what might be expected based only on US data. However, of the US companies surveyed, only Florida Public Utilities Company had a statistically significant equity beta.

It has been argued that an adjustment should be made to foreign betas before they are applied as comparators for Australian companies. However, it is submitted that such an adjustment is inappropriate - what we are really trying to ascertain amongst a number of countries is the covariance between the electricity business and the economy in which it operates – as opposed to the covariance between the business and a foreign country (in this case Australia). In practice therefore, it is submitted that international adjustments to beta lose sight of the essential fact that a beta estimates a level of volatility relative to the market with which the covariance is assessed. The essential point is that beta is a *relative* measure of covariance. That relativity is important irrespective of the volatility of one market or another.

In other words, one cannot criticise the irrelevance of a "high" beta measure in a highly volatile exchange on the basis that it will be too high for Australia since the measure simply

43 Note that even if the Blume adjustment is not used (which we strongly argue against) the overall average asset beta is 0.41 (transmission 0.38 and distribution 0.42).

44 If the non-OECD comparators (Argentina and Brazil) are removed, the overall average asset beta of the remaining comparators rises to 0.52. The average of the OECD transmission companies is 0.39 while that of the OECD based distribution companies rises to 0.55. Note in this case there is only 3 transmission comparators in the sample.

records the covariance between the stock and that (highly volatile) market – generally speaking, the beta would be even higher were the market to exhibit lower volatility.

5.1.2 Recent regulatory decisions

Beta values in recent regulatory decisions are set out in table 7.

Table 7: Asset and equity beta - recent regulatory decisions in energy sector

Year	Regulator	Decision	Asset beta	Debt beta	Equity beta
Electricity transmission					
Dec-02	ACCC	SPI PowerNet	0.40	0.00	1.00
Dec-02	ACCC	ElectraNet	0.40	0.00	1.00
Nov-01	ACCC	Powerlink	0.40	0.00	1.00
Feb-01	ACCC	SMHEA	0.40	0.00	1.00
Jan-00	ACCC	Transgrid	0.35-0.50 (0.43)	0.00-0.06 (0.03)	1.02
Electricity distribution					
Oct-01	QCA	Electricity distributors	0.45	0.28	0.70
Sep-00	ORG	Victorian distribution businesses	0.40	0.00	1.00
Dec-99	IPART	NSW distributors	0.35-0.50 (0.43)	0.06	0.97
May-99	ICRC	ACTEW (all activities)	0.40	0.12	0.82
Gas Transmission					
Dec-02	ACCC	NT Gas	0.50	0.15	1.02
Nov-02	ACCC	GasNet	0.50	0.18	0.98
Sep-01	ACCC	Moomba to Adelaide	0.50	0.06	1.16
Dec-00	ACCC	EAPL	0.50	0.06	1.16
Jun-00	ACCC	Central West Pipeline	0.60	0.00	1.50
Oct-98	ACCC	TGA (GasNet)	0.55	0.12	1.19
Oct-01	Offgar	Tubridgi	0.65	0.20	1.32
Jun-01	Offgar	Dampier to Bunbury (draft)	0.60	0.20	1.19
Apr-01	Offgar	Goldfields (draft)	0.60	0.20	1.19
Oct-00	Offgar	Parmelia pipeline	0.65	0.20	1.32
Gas distribution					
Oct-02	ESC	Vic gas distribution	0.40	0.00	1.00
Dec-01	SAIPAR	SA distribution systems	0.50	0.12	1.06
Oct-01	QCA	Qld gas distribution	0.55	0.26	0.98
Dec-00	OffGAR	Alinta (Mid West/South West)	0.55	0.20	1.07
Nov-00	ICRC	Actew	0.45	0.06	1.03
Jun-00	IPART	AGL Gas Network	0.45	0.06	1.03
Dec-99	IPART	Albury gas distribution system	0.45	0.06	1.03
Mar-99	IPART	Gt Southern energy gas network	0.45	0.06	1.03
Oct-98	ORG	Victorian gas distributors	0.55	0.12	1.19

As can be seen in table 7, regulators have adopted the following values and ranges for the re-levered equity beta:

- in electricity transmission the ACCC has largely adopted a value for the asset beta of around 0.40, resulting in an equity beta of 1.0 with a zero debt beta;
- in electricity distribution, regulators have adopted a range of 0.70 to 1.0 for the equity beta;

- in gas transmission, regulators have adopted a range of 1.0 to 1.5 for the equity beta; and
- in gas distribution, regulators have adopted a range of approximately 1.0 to 1.2 for the equity beta.

Given that in its decisions to date, regulators have either implicitly or explicitly determined that electricity transmission businesses have a higher systematic risk than electricity distribution companies, providing Transend with an asset beta higher than both of AGL and United Energy would be consistent with this observation.

5.1.3 Factors that impinge on sensitivity of cashflows to movements in economy

Customer mix

Transend's cashflow is sensitive to movements in the Tasmanian economyTransend is reliant on a few major customers for the bulk of its revenue, with five major customers accounting for over half of total revenue – a highly unusual situation in Australia.

Size effect

There is much evidence, particularly through the research of Rolf Banz[45] and Eugene Fama and Kenneth French[46] that the investment returns to small companies are greater than would be expected based upon the measured beta using CAPM. In this research, returns to

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45 R. W. Banz, "The Relationship Between Market Value and Return of Common Stocks," *Journal of Financial Economics*, November 1981.

46 For example, see E. Fama and K. French, "The Cross-Section of Expected Stock Returns", *Journal of Finance*, June 1992, pp. 427-65; "Common Risk Factors in the Returns on Stocks and Bonds", *Journal of Financial Economics*, February 1993, pp. 3-56; and "Multifactor Explanations of Asset Pricing Anomalies", *Journal of Finance*, March 1996, pp. 55-84.

companies' shares are explained by a common market factor, size and book value to market value of equity ratio; beta is an insufficient, if not ineffective, explanatory factor of security prices.

Jagannathan and Wang provide evidence on the relationship between beta, size and returns.[47] Small firms have higher returns than large firms, even after adjustment for beta. Furthermore, they show that using conventionally estimated betas provides poor explanatory power for expected returns.

There are at least five published studies of the size effect in Australia, all of which document a significant size effect.[48] Halliwell, Heaney and Sawicki find that "… in all cases the size effect provides considerable explanatory power over realized returns for the period 1980 to 1991."(p. 122)

In its ElectraNet decision, the ACCC noted that the evidence on the size effect had caused debate in four main areas:

- it may reflect data mining;
- the results may reflect the market proxy that is being tested;

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47 R. Jagannathan and Z. Wang, "The Conditional CAPM and the Cross-Section of Expected Returns", *Journal of Finance*, March 1996, pp. 3-53.

48 P. Brown, D. Keim, A. Kleidon and T. Marsh, "Stock Return Seasonalities and the Tax-Loss Selling Hypothesis", *Journal of Financial Economics*, 1983, pp. 105-27; W. Beedles, P. Dodd and R. Officer, "Regularities in Australian Share Returns", *Australian Journal of Management*, June 1988, pp. 1-29; D. Anderson, A. Lynch and N. Mathiou, "Behaviour of CAPM Anomalies in Smaller Firms: Australian Evidence", *Australian Journal of Management*, June 1990, pp. 1-38; J. Halliwell, R. Heaney and J. Sawicki, "Size and Book to Market Effects in Australian Share Markets: A Time Series Analysis", *Accounting Research Journal*, 1999, pp. 122-37; and C. Gaunt, P. Gray and J. McIvor, "The Impact of Share Price on Seasonality and Size Anomalies in Australian Equity Returns", *Accounting and Finance*, March 2000, pp. 33-50.

- concern that the results are sensitive to the results of various changes in data and methodology, including new data sets and deletion of extreme observations (survivorship bias); and
- the lack of theoretical underpinning.

We dispute that any of these claims detract from the validity of the results for a number of reasons.

Data mining

The ACCC does not seem to understand what is meant by data mining. It is when a large database is selectively tested until a desired result is obtained. The huge volume of research that has been done indicates that there is not data mining. As a result of the extensive research that continually supports the existence of a size effect, it is hard to conclude that the size effect is a result of data mining. Further, the existence of the size effect has been confirmed in numerous international markets in addition to the US.

Remnant of the market proxy

The testing that confirms a size effect has used a wide range of proxies for the market index. It has not been confined to one or two proxies. Further, international tests support that the testing is robust to challenges such as this.

Sensitivity to changes in data and methodology

This assertion is unfounded, as it is well known that a fundamental approach to confirming the robustness of a result is to subject it to different data sets and methodologies. Rather than being a challenge to the existence of a size effect, this is strong support for the effect. If the concern is that all the results do to yield exactly the same measurements of the size effect, then this is hardly surprising. The fundamental issue is whether a size effect does in fact exist? The results in that regard are remarkably consistent. In addition, it is hardly surprising that using different data sets, research designs and methodologies yield somewhat different measurements of the magnitude of the size effect.

Lack of theory

It is not correct to say that there is a lack of theory underpinning the size effect. One explanation is that the effect is related to bankruptcy risk. Small firms are far more likely to experience bankruptcy and such a risk is almost certainly going to be priced out. Another well accepted explanation for the size effect is that it reflects a liquidity premium. The equity of smaller firms is generally less liquid and a higher return is required by investors to entice them to invest in the smaller, less liquid, firm. We measure returns using a single factor model that precludes multiple sources of risk, such as bankruptcy and liquidity, therefore we observe the size effect.

While there are a number of smaller companies listed on the ASX, Transend is certainly not a large company, and is small when compared with other electricity transmission businesses operating in the NEM. This is especially the case if its equity value is assessed on the basis of the benchmark gearing of 60% assumed by the ACCC. Given that the size of Transend is dwarfed by other transmission entities, there is certainly no case for providing Transend with a beta value lower than that provided to other regulated transmission entities and arguably a strong case for a higher value.

Conclusion on asset beta

Given the inherent volatility of beta values, we dispute whether the current observations for listed utility businesses in Australia are relevant for determining a beta value for a company such as Transend. Consideration of international beta values together with regulatory precedent suggests that a range of 0.40 to 0.50 can be justified for Transend. Given factors suggesting high systematic risk and its relative size in relation to other transmission entities, we have adopted an asset beta of 0.45.

6 Gamma

The dividend imputation mechanism used in Australia is intended to ensure that profits are taxed only once for Australian resident taxpayers but this benefit is not intended for foreign shareholders. Dividends that are paid out of after-corporate-tax profits can be accompanied with a 'franking' credit to the extent of the corporate tax paid. The value of franking credits is represented with the parameter gamma (γ).

The value of franking credits will be determined at the level of the investor and will be influenced by the investor's tax circumstances. As these will differ across investors, the result will be a value of the franking credit between nil and full value (i.e., a gamma value between zero and one). There has been an increasing body of literature focused on estimating the value of gamma. The early literature generally found a value of around 0.5. Since this time, debate has become increasingly polarised between those arguing for zero and those arguing for one.

Regulators have responded to this uncertainty by setting a value within the range of 0.3 to 0.5. The ACCC's practice of adopting a value of 0.5 is consistent with regulatory practice in Australia.

The market value of distributed franking credits should be established at the market level, not the firm level. So for regulatory purposes, we agree with current regulatory practice that treats firm specific shareholding, including for Government owned businesses such as Transend, as irrelevant.

Some of the key issues in determining a gamma for the WACC revolve around:

- the identity of the marginal investor; and
- the net impact of recent taxation changes.

6.1 Identity of the marginal investor

The gamma used in the CAPM is generally derived as a market average. Nevertheless, it is the *marginal* rather than *average* value of gamma that is likely to be more appropriate for setting a forward-looking value consistent with the aims of the CAPM. This is because share prices are set by price setting (marginal) investors.[49]

This set of investors may have little relationship to the shareholder mix of a company at a point in time. For publicly listed Australian companies, the marginal investor is likely to be an international investor. This can be seen in light of the extent of foreign ownership of Australian companies and the relative size of the Australian market in global terms.

Foreign shareholders own over 28% of Australian companies[50], non-resident investors own around 37.5% of the value of the Australian Stock Exchange, the largest single shareholder group by far[51].

It is therefore clear that foreign investors exert substantial influence on Australian stock market prices. Indeed, once it is recognised that Australia is a net importer of capital and that Australian equities only represent approximately 1% of the global market, we draw two conclusions:

- the levels of foreign ownership in Australian equity markets are significant and that this can affect imputation assumptions since a foreign shareholder will at best experience considerable difficulty accessing imputation credits; and[52, 53]

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49 Officer RR (1994) "The Cost of Capital under an Imputation Tax System", Accounting and Finance, 34, 1-18.

50 ABS statistics, 5302.0 Balance of Payments and International Investment Position, September Quarter 2001.

51 Information provided by Australian Stock Exchange. Figures for 19 September 2001.

52 This holds irrespective of whether or not Australian residents are the first to invest in these companies – such investors are merely inframarginal but do not set equilibrium security

- international ownership levels are well below those assumed in fully integrated world sharemarkets.

Taken together, this suggests that an international investor, who cannot secure the benefit of imputation credits, sets the price for Australian securities. This is the case irrespective of the benefit that Australian investors can secure from imputation credits. The fact that Australians hold the bulk of securities is irrelevant here on account of the significance of international investment (all but the 1% of global investment attributed to Australia) and the impact it thereby exerts (evidenced by the material presence already in the Australian market) in price setting. These factors suggest that gamma may be as low as zero. This is consistent with a recent study by Cannavan, Finn and Gray,[54]which showed that for companies with substantial foreign ownership, the market value of tax credits is close to zero.[55]

Recently Associate Professor Martin Lally has suggested that the appropriate value for gamma should be one (1) based on his view that the model used to assess imputation credits

prices. See also Officer (1988), "A note on the Cost of Capital and Investment Evaluation for Companies under the Imputation Tax", Accounting and Finance, 28, 65-71.

53 In addition, recent tax changes require an investor to hold a stock for 45-days to be eligible for the franking credits. This effectively eliminated arbitraging and dividend stripping, resulting in the end of the secondary market for the credits and eroding the value of franking credits for foreign investors. Accordingly, the only way that foreign investors could secure any benefit from imputation credits would be through practices of dubious legality – to the extent that such "black market" activities exist (by their nature they are not well known) are likely to be accompanied by very high risk and transactions costs, which would seriously discount any such benefit derived.

54 Cannavan D., Finn F. and Gray S. (2001) "The Value of Dividend Imputation Tax Credits," unpublished working paper, Department of Commerce, The University of Queensland.

55 Nevertheless, it is recognised this area is not settled and that the result of dividend drop-off studies have indicated higher values for gamma. Nevertheless, more recent studies still suffer from selection bias, high standard users and create streaming effects in the data analysis that affect the results.

does not accommodate market segmentation.[56] His argument begins with the proposition that the Officer model for the assessment of imputation assumes a segmented market. Therefore, he asserts that the application of an international capital asset pricing model market has been rejected. Since markets are assumed as segmented by the choice of models for estimating WACC, all analysis must be constrained to assuming that the marginal shareholder is an Australian taxpayer.

We reject his analysis on this point.

In spite of any theories, it is an objective fact that the Australian sharemarket and the pricing of Australian securities is in an international market. The Australian markets are not segmented. Theoretical assumptions cannot sweep this fact aside.

We believe that the appropriate approach to these issues is as follows:

- to ignore foreign investors is to ignore the realities of our market environment so we accept that we operate in an integrated (i.e., not segmented) market;
- this suggests that we should use a version of the international CAPM (ICAPM). However, as current versions of the ICAPM do not provide an appropriate basis for the estimation of the cost of capital for regulatory purposes and are unlikely to do so for the foreseeable future, the Officer model is the best available proxy for the ICAPM. Our use of the Officer model does not require that we assume segmented markets;
- consistent with our assumption that we operate in integrated markets, and consistent with the facts regarding the activities of foreign investors in the price setting process in Australia, we extend our view of integrated markets to the valuation of dividend imputation credits.

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56 Lally, M., (2002), "The cost of capital under dividend imputation," a report prepared for the Australian Competition and Consumer Commission.

We also note that in a recent forum, Professor Officer (whose model was applied by Associate Professor Martin Lally) suggested that there was no case to move away from current gamma settings at this time.[57]

6.2 Recent changes to taxation law

To the extent that Australian domestic conditions are relevant to the setting of gamma, NECG believes that it is too early to assess whether changes to capital gains tax and the full flow through of imputation credits has had any impact on the valuation of gamma for regulatory purposes.

NECG believes there is good reason to suggest there would be little or no change to the valuation of imputation credits based upon the impact of the tax changes on the marginal (that is, foreign) investor. The tax law change will only impact gamma to the extent that the impacted investors play a part in the determination of equilibrium security prices, that is, they are marginal investors. We have already stated that it is not likely to be the case that Australian tax residents are the marginal investors because of the extent of foreign ownership in Australia and the extent of foreign investment by Australians as well as relevant research in other countries. Tax and imputation considerations are but one factor influencing valuation decisions.

This view is shared by the QCA who note that the taxation effects are at best uncertain:

> While the changes to capital gains tax and the changes which allow the full flow through of imputation credits to resident taxpayers may have an impact on these levels, there is currently no clear indication of their impact. Further, the influences may be offsetting as the New Tax System may tend to reduce the level of dividend distribution, but may increase the utilisation rate.[58]

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57 Key WACC Issues in the Regulation of Electricity and Gas, Transmission, an open forum sponsored by SPI PowerNet, ElectraNet SA and GasNet, Monday 24 June 2002.

58 Queensland Competition Authority, Draft Report for Consultation, Burdekin Haughton Water Supply Scheme: Assessment of Certain Pricing Matters relating to the Burdekin River Irrigation Area, September 2002, p84.

Recommendation

A gamma value of zero is consistent with the marginal shareholder being an international investor. NECG acknowledges that a gamma of 0.50 or below is well established in Australian regulatory decision-making. We also accept that there is considerable uncertainty associated with the value of gamma and that this uncertainty is unlikely to be definitively resolved in the near term. We do not believe there is a basis for any increase in gamma above 0.50, but the case for adopting a gamma value below 0.50 is not yet definitive. Therefore, we currently support a continuation of using a gamma of 0.50.

7 Conclusions

This paper has developed our view of an appropriate WACC for Transend. As noted in the introduction, the role of the regulatory WACC should be to reflect the opportunity cost of investment. Therefore, an important policy consideration for the ACCC is to ensure that incentives for investment are not adversely affected by the WACC provided to the businesses.

It is becoming increasingly accepted that the regulatory consequences of setting too low a WACC in the form of insufficient investment are greater than those of setting too high a WACC (short run super-normal profits), a point noted by the Productivity Commission:

> The possible disincentives for investment in essential infrastructure services are the main concern. In essence, third party access over the longer term is only possible if there is investment to make these services available on a continuing basis. Such investment may be threatened if inappropriate provision of access, or regulated terms and conditions of access, lead to insufficient returns for facility owners.
>
> While the denial or monopoly pricing of access also impose costs on the community (see above), they do not threaten the continued availability of the essential services concerned. Thus, over the longer term, the costs of inappropriate intervention in this area are likely to be greater than the costs of not intervening when action is warranted. The substantial information and other difficulties that confront regulators in establishing access terms and conditions, make this asymmetry in the benefits and costs of access regulation even more important in a policy context.[59]

This suggests that there is a strong public interest argument in favour of erring on the side of a higher WACC than has been customary in Australian regulatory decision making in recent years.

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59 Productivity Commission, "Review of the National Access Regime. Position Paper", March 2001, pp xviii-xix.

Calculation of WACC

Using the information in this report on the individual WACC parameters we are now able to calculate the "vanilla" WACC for Transend, as follows:

$$WACC = r_e (E/V) + r_d (D/V)$$

Table 8 summarises our parameter estimates, which result in a nominal, post-tax "vanilla" WACC for Transend of 8.80%. This WACC is derived from parameter values that in many cases are identical to that provided in some recent regulatory decisions. In other cases, as noted in this report there are strong arguments for higher values of some variables – such as beta – and thereby the WACC presented here is unlikely to provide excessive returns to investors in Transend.

Table 8: WACC rates

WACC/CAPM parameters	Estimate
Risk-free rate	5.24%
Debt proportion	60%
Equity proportion	40%
Debt risk margin	1.445%
Cost of debt	6.69%
Market-risk premium	6.0%
Asset beta	0.45
Debt beta	0
Tax rate	30%
Franking credits – gamma	50%
Equity beta	1.12
Nominal post tax cost of equity	11.96%
Nominal, post-tax "vanilla" WACC	8.80%