Australian Energy Regulator

Tasmanian Electricity Transmission Revenue Reset

TasNetworks Application

A response

by

The Major Energy Users Inc

August 2014

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission.

The content and conclusions reached are the work of the MEU and its consultants.

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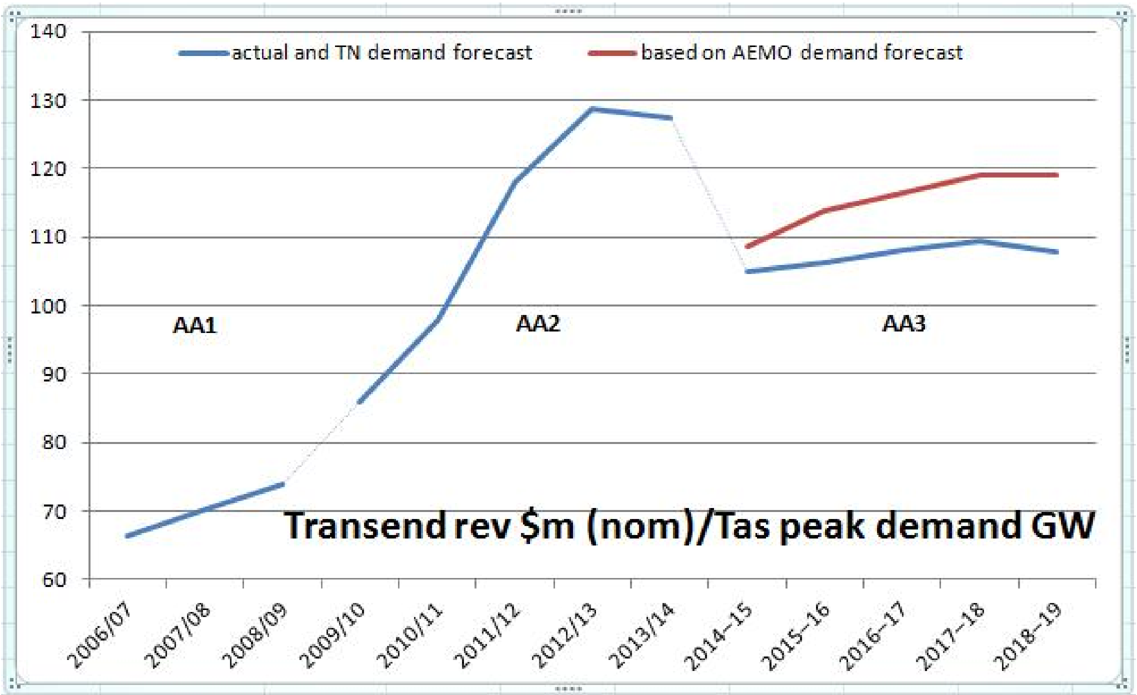
Executive Summary

The Major Energy Users (MEU) welcomes the opportunity for presenting its views on the application from TasNetworks (TN) for a reset of the electricity transmission costs in Tasmania.

The MEU notes that the proposal from TN results in a significant reduction in revenue compared to that which applied in the current period. It also reflects a reduction in the cost to users in terms of cost per MW of demand and cost per MWh. However, what is concerning is that the reduction in prices to consumers is not as great as might have been imagined from the proposed reduction in revenue. This is shown in the following chart.



Source: TN benchmarking RIN, AEMO June '14 NEFR, TN application

On this comparative basis, it is clear that the TN proposal for its revenue still results in high costs to consumers and as the savings on a usage basis are close to current levels, might be somewhat overstated and should be reduced further.

The MEU has investigated the reasons why TN revenue shows a higher increase than might be appropriate. In its assessment the MEU noted that:

- Whilst TN has followed the AER guideline with respect to calculating the rate of return, the MEU considers that TN has still included for a cost of debt that is too high, both in relation to the AER proposed benchmark cost of debt and compared to the actual costs TN incurs or is likely to incur in the coming regulatory period. Further, the MEU notes that the risk free rate has fallen considerably from when TN calculated its return on equity and this results in a considerable reduction in the proposed cost of equity. The MEU considers that adjusting the risk free rate to current levels, adjusting the cost of debt to current levels and using the lower equity beta implied by Professor Henry in his latest paper, a WACC of more than 100 bp lower than that claimed by TN should result. A decrease in WACC of this magnitude would reduce the allowed revenue by nearly 10%.

- The MEU has reviewed the TN claims for opex and considers that TN has overstated its requirements. The benchmarking provided by TN shows that TN still is not operating anywhere near the efficient frontier. The AER needs to carry out in-depth analysis and further benchmarking to provide a view of where the efficient frontier for TN is, and to implement a transition for TN opex to be set at this level.

- TN recognises that its need for network augmentation had to reduce because of the falling demand and consumption of electricity in Tasmania yet it still seeks to augment parts of the network. Analysis of the proposed augmentation capex indicates that the proposed works are not yet defined as being needed or demonstrably cost beneficial. The MEU considers that these projects not be included in the allowed capex but be considered contingency projects to be implemented when a confirmed need is identified.

- The claim for replacement capex is not supported by the assessment of the average age of the network and should be reduced. It is clear that the average age to the TN network is considerably younger than would be expected from efficient capex, indicating that little renewal capex is required in the new period. There are other elements of the capex proposal that are not consistent with historic performance.

- The Network Capability Incentive Parameter Action Plan (NCIPAP) proposal by TN is seen by MEU as a "grab for money" with most of its projects either being work that TN should have done under its normal opex/capex programs or delivering benefits over excessively extended periods. The derivation of the supposed benefits is suspect and there is no certainty that the proposed works will deliver the benefits to consumers that are used to justify the works proposed. No project with a payback exceeding 2 years should be allowed under the NCIPAP to reflect the approach used in a competitive environment.

- The pricing methodology is unacceptable as it is clearly not cost reflective. The MEU considers that the pricing methodology should be based on the peak usage each user imposes the network rather than using the lower of demand and consumption for non-locational TUoS and common service. This is the approach proposed by TransGrid in its new pricing methodology and is, subject to some modifications recommended by MEU, a pricing methodology which is much more cost reflective than the methodology proposed by TN.

Overall, whilst the proposal from TN is better than that for the current period, there are a number of aspects that must be implemented to provide consumers with an efficient outcome. In particular, although TN has acted to improve its efficiency, the TN proposal is not considered to deliver outcomes for consumers that are expected when considering the extensive work that has been carried out over the past few years to address the ever burgeoning costs for the provision of electricity transmission network services in Tasmania.

The MEU expected that the TN proposal would result in considerably greater reductions than have resulted.

In addition to the analysis of the TN proposal, the MEU has provided responses to the questions raised in the AER Issues Paper prepared for this revenue reset of TN.

1. Introduction

1.1 The MEU

The Major Energy Users (MEU) welcomes the opportunity to provide comments on the application for a revenue reset for the Tasmanian electricity transmission system by TasNetworks (TN).

Analysis of the electricity usage by the members of MEU shows that in aggregate they consume a significant proportion of the electricity generated in Tasmania. As such, they are highly dependent on the transmission network to deliver efficiently the electricity so essential to their operations. Being heavily dependent on suppliers of hardware and services, members also have an obligation to represent the views of their local suppliers. With this in mind, the members require their views to not only represent the views of large energy users but also those of smaller power using facilities, and even of the residences used by their workforces.

The companies represented by the MEU (and their suppliers) have identified that they have a strong interest in the **cost** of the energy networks services as this comprises a large cost element in their electricity (and gas) bills.

Although electricity is an essential source of energy required by each member company in order to maintain operations, a failure in the supply of electricity (or gas) effectively will cause every business affected to cease production. Our members' experiences are no different. Thus the **reliable supply** of electricity (and gas) is an essential element of each member's business operations.

With the introduction of highly sensitive equipment required to maintain operations at the highest level of productivity, the **quality** of energy supplies has become increasingly important with the focus on the performance of the distribution businesses because they primarily control the quality of electricity and gas delivered, although in Tasmania the large users are directly connected to the transmission network. Variation of electricity voltage (especially voltage sags, momentary interruptions, and transients) by even small amounts now has the ability to shut down critical elements of many production processes. Thus member companies have become increasingly more dependent on the quality of electricity and gas services supplied.

Each of the businesses represented by MEU has invested considerable capital in establishing their operations and in order that they can recover the capital costs invested, long-term **sustainability** of energy supplies is required. If sustainable supplies of energy are not available into the future these investments will have little value.

Accordingly, the MEU is keen to address the issues that impact on the **cost, reliability, quality** and the long term **sustainability** of their gas and electricity supplies.

The members of MEU have identified that transmission plays a pivotal role in the electricity market. This role encompasses the ability of consumers to identify the optimum location for investment of its facilities and providing the facility for generators to also locate where they can provide the lowest cost for electricity generation. Equally, consumers recognise that the cost of providing the transmission system is not an insignificant element of the total cost of delivered electricity, and due consideration must be given to ensure there is a balance between the two competing elements.

Although the MEU had actively participated in previous Australian Energy Regulator (AER) pricing and revenue reviews of the Tasmanian transmission and distribution networks, it was not contacted by TN to discuss its current application despite MEU representing a significant number of large energy users. However, MEU members have advised that they have had dialogue with TN regarding the reset and other matters.

The MEU remains available for consultations with TasNetworks

1.2 The scope of this review

The MEU notes that this review is being undertaken in a period where there is considerable stress on electricity consumers as the cost of electricity has risen dramatically in recent years. To a significant extent this increase has been a result of changes in the National Electricity Rules (NER) in 2006 and 2007 that have had the effect of very substantially disadvantaging consumer interests and resulted in much economic and social hardship.

Since then, Chapter 6A of the rules has been significantly revised and the AER has developed new guidelines to implement the new rules. It is noted that TN has elected to generally comply with the approaches set out in these guidelines. This is welcomed by the MEU as the new guidelines were developed after wide consultation and with significant consumer input. In the MEU's view, it is important for the development of a more cooperative and constructive approach to network regulation that the AER's guidelines are followed and that any variation from the guidelines is only undertaken in consultation with consumers.

It has been very disappointing for consumers to see that some other transmission network service providers (TNSPs) and distribution network service providers (DNSPs) have elected not to follow this course in their proposals,[1] and have persisted in an outdated confrontational approach to network regulation. The approach is outdated because it completely fails to recognise the changes occurring in the energy market around them, be it changes in the structure of the economy broadly, greater efficiency, or simply businesses and households responding to rapid price rises.

In theses respects at least, TN has set a benchmark for the other TNSPs and DNSPs by following the guidelines, by starting to listen to the concerns of their customers and by proposing reductions in nominal prices and much reduced investment levels. Only TN, for instance, has been able to stabilise the growth in its regulated asset base (RAB) to around CPI. In other instances, the RAB has grown at around 5 per cent or more per annum, putting a very significant and sustained pressure on network prices in this regulatory period and the next.

That does not, however, mean that the MEU accepts all aspects of the TN proposal. The MEU's submission will demonstrate areas of concern to the MEU. What it *does mean* is that TN's approach offers some hope for greater cooperation between networks, regulators and consumers built around a growing recognition of consumers' needs and preferences.

Such an outcome is particularly important to Tasmania. Some one third of TN's transmission revenue comes from the direct end-user customers. If these customers leave the Tasmanian market, there will be significant repercussions for the price of transmission services to all Tasmanian consumers. Constructive dialogue on the reform of transmission pricing is therefore a key priority for both TN and consumers - in this regard the MEU would be pleased to have dialogue with TN about a new pricing approach.

At a high level, TN appears to recognise the stresses that consumers face and it is seeking to reduce the costs for the service it provides. On deeper review, it would appear that TN could do more to address the costs that they could then pass onto consumers.

The new rules provide the AER with greater discretionary powers and the associated guidelines are an attempt to show stakeholders how the AER intends to use this greater discretion. To a greater extent than applied under the old rules, the revenue allowance provided to a network service provider (NSP) must be seen as "a bucket of money" which provides sufficient funds for an NSP to provide the service rather than discrete and separate allowances for the tasks that must be undertaken to provide the service.

In addition to ensuring the funds provided are used efficiently, the AER has the responsibility to ensure that the funds are acquired in a way that provides

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[1] This includes the NSW TNSPs, TransGrid, and Direct Link, and the three NSW DNSPs, Ausgrid, Endeavour Energy and Essential Energy, whose proposals were also submitted to the AER in May 2014.

clear signals to consumers to be able to modify their use of the services. This means that the AER must ensure that the pricing structures that are developed as part of the revenue reset review provide appropriate signals to consumers. In turn, consumers are incentivised to take actions so that the network can be operated more efficiently and the assets have maximum utilization consistent with a reliable service performance. By this means the costs for both current and future users of the service can reflect value for the money consumers are required to spend on the services.

For this reason, the MEU is vitally interested, not only in the overall quantum of the revenue proposal, but in the approach adopted by TN to network pricing. The National Electricity Rules (NER) sets out principles of cost recovery rather than specific pricing rules, thereby providing considerable flexibility to the transmission networks in the way they set prices. It would appear that generally TN wants to continue the current approach.

The MEU urges TN to consult further with its customers on these pricing issues. It is important to be fair to all consumers, but it is also important to map out a path to more efficient and cost reflective pricing. Such efficient pricing benefits all consumers in the long-run as consumers are then incentivised to take actions that will progressively reduce network costs.

For example, Tasmanian consumers have, in the past, not received accurate signals on locational costs nor the costs of peak demand, and the benefits of demand management. Progressively adjusting prices to signal these costs and benefits will have a significant impact on TN's future costs.

The MEU has many long-standing concerns with the approach used by Transend (TE) in setting its transmission prices in the past, particularly for direct connected customers. This revenue reset process provides TN with the opportunity to implement change. The MEU expects these to be progressively addressed in the new regulatory period.

1.3 A summary view of the TN application

Before assessing the detail of the proposal, the MEU highlights the fact that TN is a merger of the Tasmanian transmission business (Transend - TE) with the Tasmanian distribution business, Aurora, with the express aim of achieving greater efficiencies particularly in overhead costs. This merger occurred on the 1 July 2014. However, the MEU accepts that the current proposal concerns the transmission business only. References to TasNetworks and Transend in this submission will, therefore, be references to the transmission business only.

Nevertheless, the MEU considers that TN's proposed transmission costs should reflect the savings that come from the merger of the two businesses. For instance, the MEU would expect to see significant and progressive reductions in costs, particularly operating costs (opex). The MEU would also expect to see some savings in capital costs reflecting some economies of scale. This submission will consider whether these expectations for costs savings have been adequately met.

TN is proposing a significant reduction in its revenue allowance and average prices in the first year of the new regulatory period followed by relatively small increases in nominal prices (decreases in real prices) for the remaining four years. The reduction in the revenue requirement reflects a number of factors:

- Lower cost of capital compared to the previous Transend determination by some 240 basis points (nominal);
- Significant reduction in capital expenditure (capex) compared to the previous determination; and
- Savings in operating costs (opex).

The reduction proposed for 2014/15 is greater than that proposed in the transitional determination (April 2014). In addition, TN had lowered its prices and therefore its total revenues in 2013/14 relative to the revenue allowed by the AER for 2013/14, stating that this was because of lower costs in 2013/14.

This is potentially a significant saving to Tasmanian consumers. Under a ‘revenue cap’ regulatory framework (which is applied to all transmission companies), the rules in Chapter 6A allow the TNSP to recover that revenue gap in the subsequent year(s).

It is notable, therefore, that of all the TNSPs and DNSPs submitting proposals in May 2014, only TN has chosen adopt the approach of both lower (relative) prices in 2013/14 and not seeking recovery of the lower revenue in the following year (2014/15).

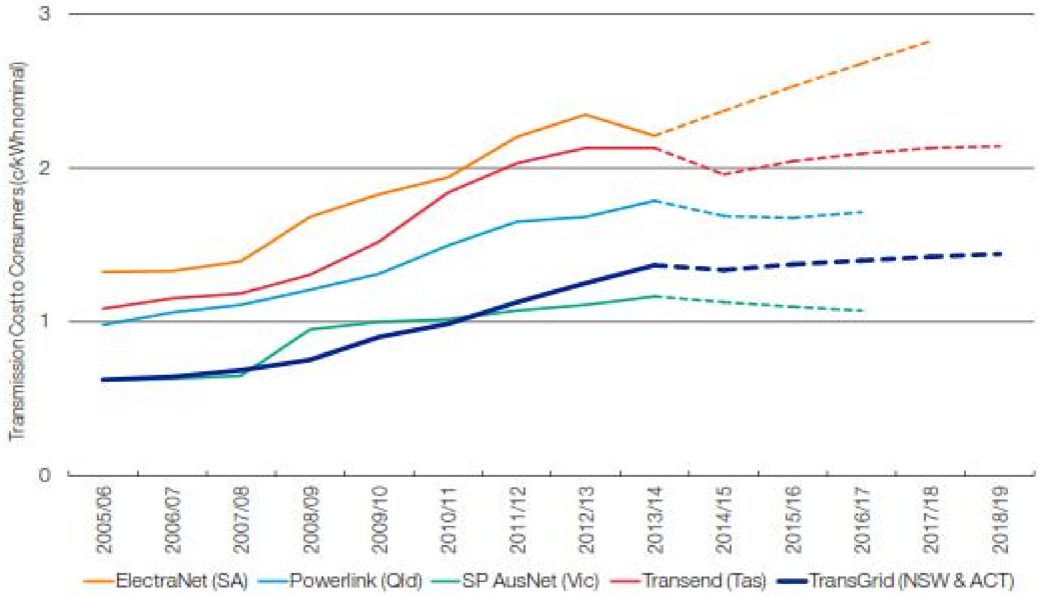
While TN's revenue proposal provides some relief and reverses the destructive trend seen in the historical price rises, the MEU believes there are still opportunities for further reduction in capex and opex. These are set out in sections 5 and 6 below.

In particular, the MEU considers that the proposal must be seen in the context of the very high transmission prices that TN’s customers currently face. That is, TN’s proposed price reductions are coming off a very high revenue allowance, which in turn reflected the excessively rapid build-up of investment in the regulatory period 2009-14 and earlier.

This is illustrated in the figure 2.2 in the TransGrid revenue proposal[2] . While it reflects TN’s transitional proposal, it is still illustrative of the very significant growth in the transmission prices facing Tasmanian consumers during 2009-14. TN continues to have the second highest prices through 2015-19.

[2] Source: TransGrid, *Regulatory Proposal for 1 July 2015 to 30 June 2019, page 18*

Figure 2.2
Transmission Cost to Consumers



Source: AER performance reports, transmission revenue determinations, transitional transmission determination for Transend and National Electricity Forecasting Report.

Another way of looking at this, is that TN's average prices almost doubled over the last six years from just over $10 MWh to over $20 MWh, an increase of over 200 per cent.

In 2009, it was pointed out in responses to the TE application for the last period (AA2), that TE was unjustifiably claiming a massive increase in its costs, even accepting that there was an increase in consumption and demand forecasts. However these forecasts were completely wrong providing TE with considerable revenue that it did not require. It is the view of the MEU that the revenue which was acquired unnecessarily must be considered within this proposal, and taken into consideration when TN is making claims for increases in elements of capex. Whilst TE did reduce its revenues in the last two years, more of this windfall of revenue should have been reallocated back to the consumer rather than delivered to the TE shareholder.

The AER therefore needs to assess this application on the basis that the cost rise in the last period (AA2) was demonstrably excessive.

The MEU notes that TN revenue is decreasing in nominal terms between 2013-14 and 2014-15 years. This is consistent with TN's proposed savings in both capex and opex, and in the considerable reduction in the cost of capital that is not offset by growth in the RAB itself. The overall reduction relative to the actual 2013-14 is some 22 per cent, in nominal terms (or 18 per cent in real terms).

Relative to the AER's allowance for 2013-14, the reduction is even more noteworthy, namely 26.5 per cent. More than half of this reduction between 2013-14 and 2014-15 is explained by the reduction in the cost of capital from 10 per cent to a forecast 7.58 per cent (based on current interest rates).

However, the MEU is concerned that the revenue path begins to rise in the latter years. In part this is a function of the proposed 'smoothing' of the revenue path (see Table 11.2 in the Proposal), such that Year 2 to Year 5 increases are held at a constant (CPI – 0.5%). In addition, there is the pressure of increased opex as noted earlier in this section.

In a competitive market, falling demand would need to be addressed through lower prices and the markets settle at a new equilibrium. In a regulated market such as that governed under the NER and NEL, however, these forces do not apply. When revenue is capped in a regulated market, then average prices tend to go up with falling demand.

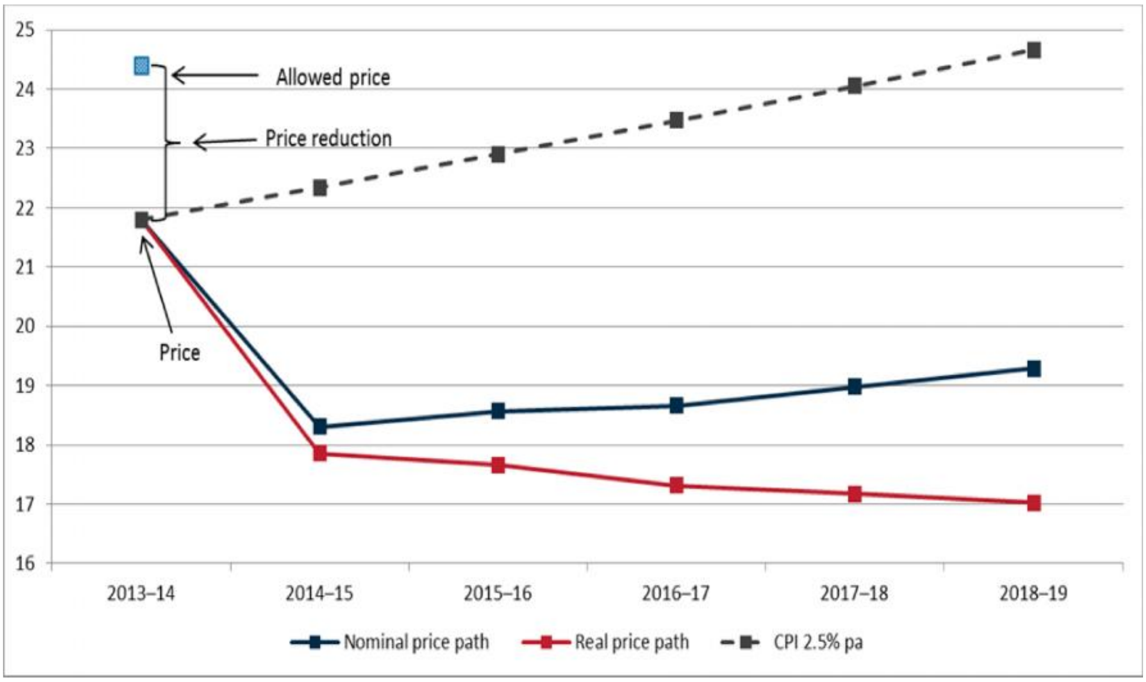
It is for this reason, that the MEU urges the AER to set revenues bearing in mind the natural equilibrium point, and to do so through a very close review of all these drivers of revenues, even when the proposed revenue is reasonably 'flat'. Consumers are not just seeking a 'better' TNSP (or DNSP), they are seeking a TNSP that is operating at an efficient benchmark level and striving for the efficiency frontier suitable for its circumstances. The MEU considers TN is not yet near the efficient frontier.

Although the TN proposal is a step reduction in revenue there is a continuing trend of increasing revenues which TN seems to assert will be offset by increasing demand and consumption. In this regard, it is important to note there are considerable differences between TN's forecasts in demand and consumption and the Australian Energy Market Operator (AEMO) 2014 National Electricity Forecast Report (NEFR) forecasts which show a continuing decline in usage. The NEFR forecasts suggest that both consumption and demand are unlikely to exceed the Tasmanian peak demand and consumption recorded in 2008/09 in the next decade.

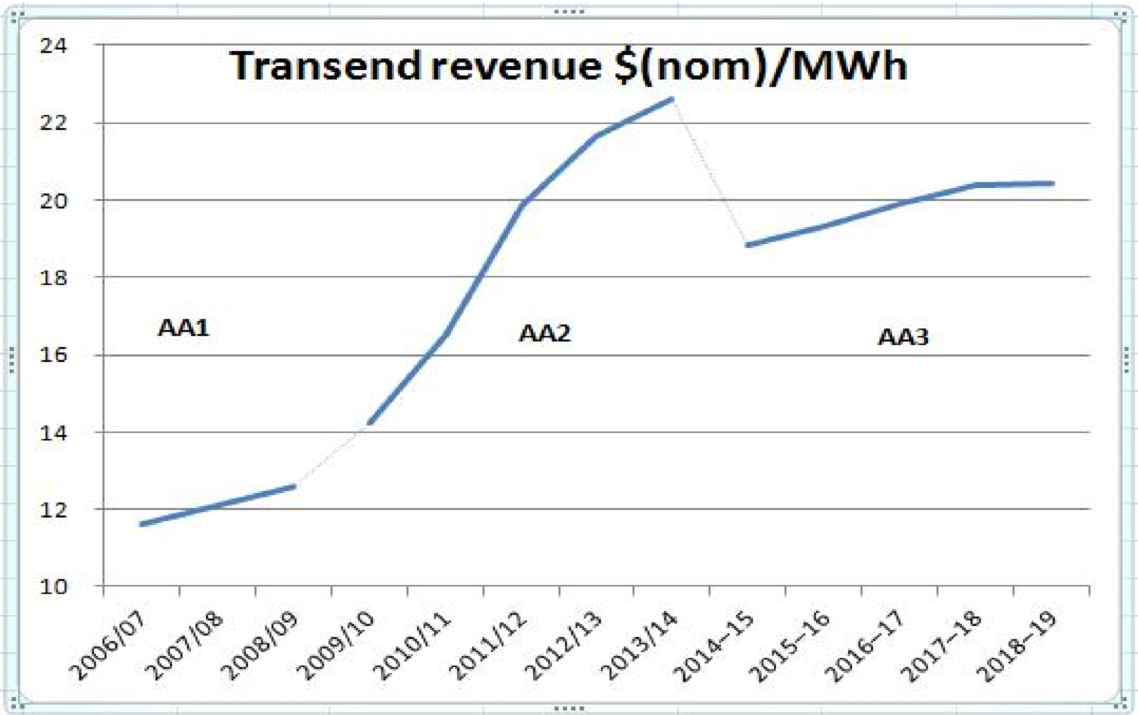
TN refers to this dichotomy and considers that its forecasts are more robust in terms of Tasmanian conditions. What is important is that these forecasts have a major impact on the prices that consumers see.

The figure below[3] illustrates TN's prices based on its consumption forecasts.

[3] Source: Transend, *Transmission Regulatory Proposal,* May 2014, p 115.



In contrast, the MEU has plotted the TN actual and forecast revenue against actual consumption and NEFR forecast consumption and presents a slightly different view on the impact of the revenue reductions and highlights the impact of assumptions used for forecast consumption. Using the NEFR forecast consumptions results in the prices rising more than indicated by TN and to go above $20/MWh (ie more than 5% higher then TN forecasts) by the end of the period AA3.



Source: TN application, AEMO data, TN benchmarking RIN, Tas NEFR 2014, AER FD transition year

The chart highlights some clear differences.

Firstly it shows that TE prices have risen from about $13/MWh at the end of AA1 to nearly $23/MWh at the end of AA2. This puts into clear perspective what the cost impact on consumers has been over the long term as a result of the TE revenue reset in 2009.

Secondly, it shows that prices to consumers whilst showing some reduction at the start of AA3 are heading back to the high levels seen at the end of AA2 and which governments and other stakeholders have identified as totally unacceptable.

Thirdly, it shows that the initial price reductions are not sustained.

Overall, the MEU would have expected considerably lower prices for the next period, rather than a short term reduction in the current excessively high prices seen at the moment with a trend back to the high prices currently seen.

Against this background, we consider that the AER has a clear responsibility to ensure a certain amount of discipline is placed on TN and that all claimed costs can be justified and are economically efficient. The MEU would expect given the under-runs in both capex and opex allowances in the current period that much of the new claims for allowances should be rejected for the next period.

1.4 Challenges for TN

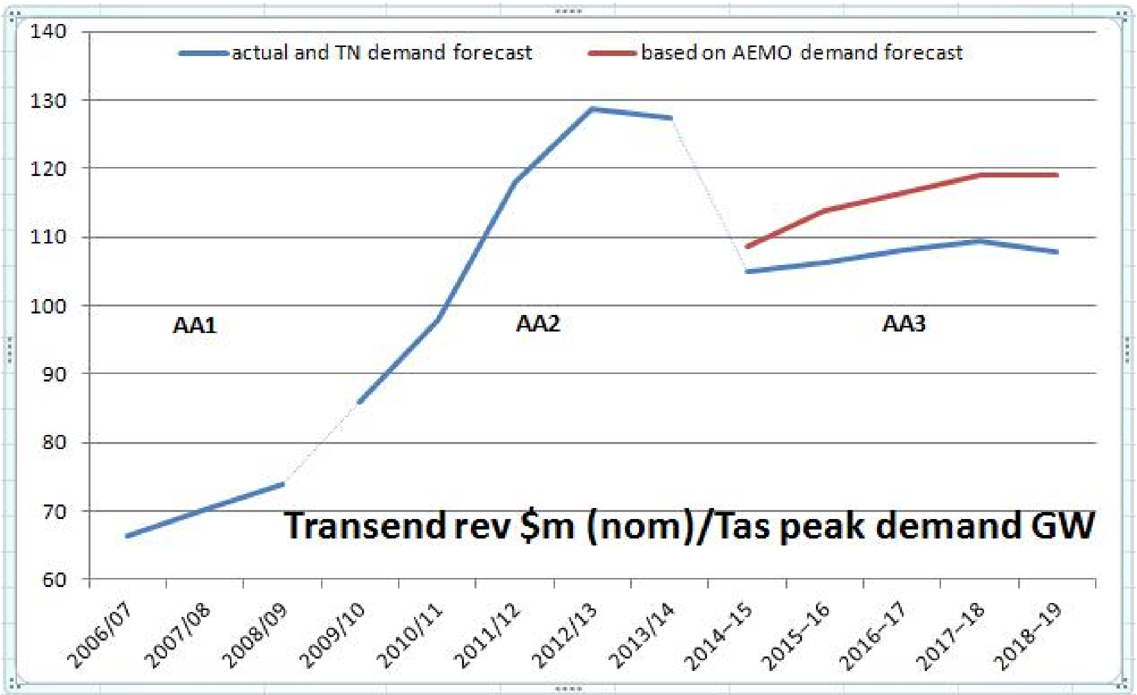
The MEU is aware that TN faces some unique challenges of relatively low population density and economic growth, difficult topography, dependence on a few very large customers and a complex mix of large and small-scale generation sources spread out across the state. A further difficulty for TN is its role in supplying electricity from these dispersed generators to Bell Bay for transmission across Bass Straight to for delivery of power to Victoria. TN appears likely to receive some additional net revenue however, from July 2015 with the introduction of inter-regional transmission use of system pricing.

However, while important, these factors do not of themselves explain the relatively fast rate of growth in costs and prices between 2009 and 2014. The AER therefore needs to assess TN's proposal on the basis that the price rises in the last period (AA2) were demonstrably excessive and reflected, in turn, overly optimistic energy and demand forecasts, as well as higher opex and capex forecasts.

The MEU believes that continuous improvement in efficiency is critical to managing prices, particularly in an era of declining or stagnant demand growth. Overall, the MEU would have expected considerably lower costs for the next period rather than the return to growth in nominal terms, particularly given the high costs that have prevailed in the past and the stated drive for greater efficiency.

TN indicates that its revenue will fall in this regulatory period (AA3) below the revenue that it had in the last period (AA2). The MEU sees that this is a sensible response to falling consumption and a virtually static demand

The MEU recognizes that TN costs are driven by the peak demands that consumers impose on the region. To assess the TN application the MEU has calculated actual and forecast TN revenue and divided this by the actual Tasmanian peak demands. As TN has forecast a different future demand to that developed by AEMO, the MEU has also calculated the revenue/demand based on the AEMO assessment. The following chart shows the cost impact on consumers using the TN developed forecast of peak demands and the AEMO forecast (50% PoE) in the 2014 NEFR for Tasmania.



Source: TN application, AEMO data, TN benchmarking RIN, Tas NEFR 2014, AER FD transition year

What the above clearly demonstrates is the impact of the reasonably static regional demand since 2006/07 coupled to the increased revenue sought by TN for the current period (AA2). It shows that the initial reduction resulting from the reduced revenue for the forecast period AA3 and the differences that using the different forecasts for peak demand from the two sources - TN (with demand increasing) and AEMO (with demand static) for period AA3. Whilst there is some rationale for the increased costs for the last period (AA2) as there was forecast for an increasing demand when TN commenced AA2, there is no excuse for continuing this trend now that the forecasts of demand are much lower than those underpinning the AA2 revenue allowances. The MEU notes that if a similar chart had been prepared reflecting consumption rather than demand, the comparisons would be even more stark and the conclusions stronger

At its most fundamental level, even the reduction in selling prices of nearly 20% between 2013-14 and the TN forecast revenue for 2014-15 still keeps the cost to customers at a very high level and by the end of the AA3 period, the costs are approaching a similar level to those seen as unacceptable now.

1.5 The materiality of transmission costs

It is often alleged (particularly by TNSPs) that of all the costs that consumers incur from the electricity supply chain, transmission charges are the least. Other than losses and market operation costs, this statement has validity.

However, transmission costs can be significant. The closer a consumer is to the transmission supply point and the larger the demand of the consumer, the more significant transmission costs can become. It is, therefore, essential that transmission costs are <u>not</u> treated as insignificant, and are addressed in a comprehensive manner.

1.6 Consumer engagement and AER questions

The MEU accepts that the formal process for consumer engagement is still very much in its formative phase. The introduction of new formal requirements for consumer engagement in the rules, and under the AER's Consumer Engagement Guideline (November 2013), is another step that builds on the work most TNSPs and DNSPs should have been undertaking.

TN is no exception. It has developed a more structured approach incorporating both the AER's Guideline and the 'core values' adopted by the International Association of Public Participation (IAPP). The MEU considers it is useful to incorporate other methods of enhancing consumer engagement to supplement the AER Guideline, particularly given that inherent difficulty of conducting a broad based engagement process.

The MEU also agrees that it is useful to consider transmission customers in two groups, as suggested by TN; namely:[4]

- Transmission customers who are directly connected to the transmission networks; and
- All other consumers who are connected to the distribution network. .

These two groups do have very different needs and also very different levels of exposure to transmission pricing. Transmission customers see very directly

[4] TasNetworks, *Regulatory Proposal*, May 2014, p 30.

what their TNSP is charging them and feel, very directly, the impact of any prices movements and service quality changes.

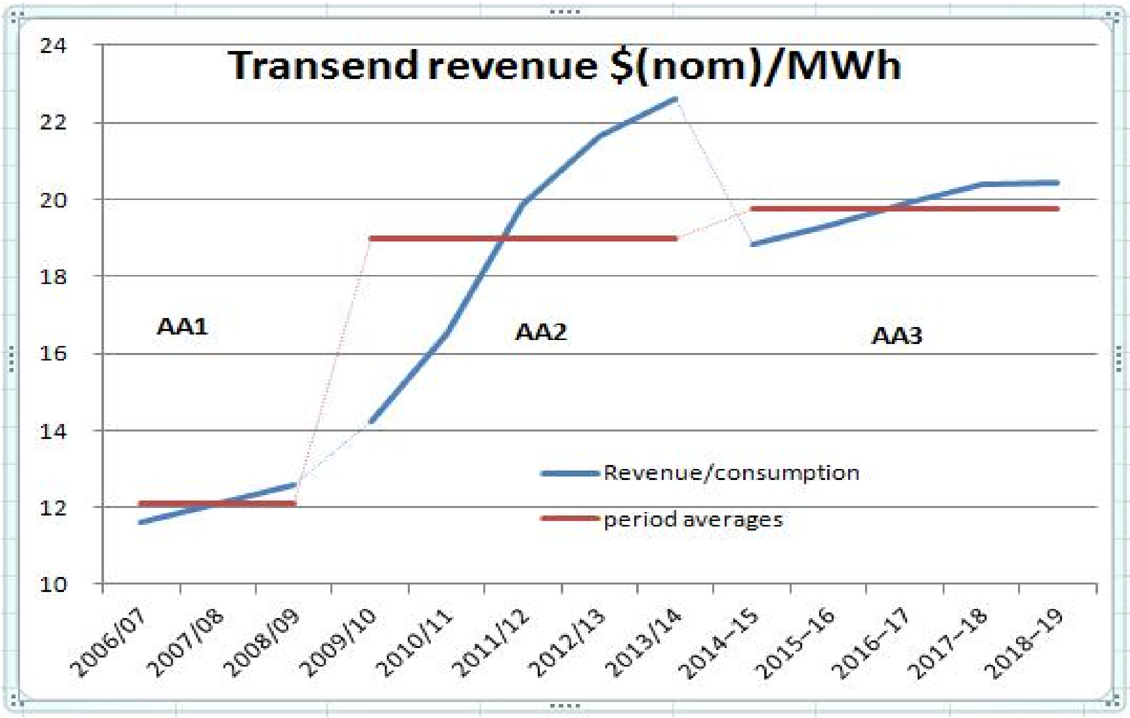
Distribution customers generally do not see a separate transmission bill; their relationships are with a retailer and distributor (in the case of Tasmania, this was Aurora). This was borne out in the research reports provided by TN. The great majority of smaller customers did not know what the transmission company does or what it charges; their concerns were with Aurora rather than Transend.[5] No doubt, this confusion will continue or even increase with the amalgamation of Transend and Aurora into TasNetworks.

The MEU accepts that the formal process for consumer engagement is still very much in its formative phase. The introduction of formal consumer engagement has led to an improvement in network responsiveness to specific issues confronting consumers, but much more can be done.

The MEU notes that TN has had considerable discussion with its direct connected customers and the MEU appreciates this. On table 3.3 of the proposal, TN lists many of the concerns that its customers have voiced and provides responses indicating that it has plans in place to address the concerns raised. The responses, therefore, indicate that TN has "heard" the concerns but the outcomes, whilst better than in period AA2, still do not go far enough to address the concerns that its customers have. Further, though TN may have "heard" consumers' views, it still needs to put these into actions.

As noted in the section 1.3 above, prices have risen from ~$12/MWh to well over $22/MWh over the last 5-6 years. Using the same chart as in section 1.3 of revenue related to consumption average prices over the three periods have been added

[5] TasNetworks, *Regulatory Proposal*, May 2014, appendix 03, pp 2-4



: TN application, AEMO data, TN benchmarking RIN, Tas NEFR 2014, AER FD transition year

This shows that the average of prices in AA1 were about $12/MWh, the average prices for AA2 were about $19/MWh and the average of prices forecast for AA3 show a small increase over the averages for AA2 - an outcome that was not expected in light of TN responding to customer concerns as prices have not really fallen when comparing averages at each reset.

TN comments (page 36)

> "In terms of the price and reliability trade-off, there are no clear, unambiguous answers about whether price or reliability—the two major issues for consumers identified through both the telephone survey and the workshops—should be our primary objective. In particular, the risk of a less reliable service was not accepted as a trade-off for lower prices. By the same token, an increase in reliability was also not supported if it came at a higher price."

TN provides a pie chart (figure 3.1 in its proposal) implying that 80% of customers are content to pay the same transmission price for the same reliability. The MEU does not doubt this but also notes that for a comprehensive assessment of such a fraught issue, there have to be clear savings/premiums provided and quantified reliability outcomes before any substantive conclusions can be drawn. At a very high level, the MEU considers that considerable reductions in price could be achieved without discernable reductions in reliability but TN has not investigated this aspect.

While accepting that the TN engagement program is better than what TN has done in the past, the MEU considers that the amount of time needed to explain to stakeholders on what TN does and the service it provides would have absorbed much of the time provided in each of the activities. Even if the full amount of time was dedicated to assessing substantive issues, the experience of the MEU is that this falls well short of the time needed to fully understand what TN does, the costs it charges for the service it provides and whether consumers are getting value for money. The MEU considers that TN needs to address this aspect in its continuing consumer engagement program.

The MEU responses to the AER questions in its issues paper are below

	AER question	MEU response
1	What is your view on the accessibility of the TN information provided	Considerable information is available and is reasonably accessible. TN could provide more information through its website
2	What was your role in the engagement process and what were the objectives of the engagement	Some MEU members report that they attended some of the TN engagement processes. The MEU itself was not advised of the engagement functions. MEU members report that they attended with the desire to learn more. The MEU cannot comment on what the TN objectives were.
3	How much time was provided between the engagement activity and the application being finalised.	The MEU considers that the time frames could have precluded some consumer views having much impact on the detailed development of the proposal. The engagement with MEU members appears to have been carried out early enough for some of the views to have been incorporated.
4	If you were consulted as part of the consumer engagement undertaken by TN were you given options for expenditure? If yes, for each option were you asked to give preferences? For each option were you given cost and price information? Did the options cover operating expenditure and capital expenditure?	The MEU did not attend the TN engagement functions.
5	Please provide any comments on how effective you believe	MEU members who attended the TN forums report that their comments would have had little impact on the revenue

	the consumer engagement conducted by TN was in responding to consumer concerns, with examples where possible (i.e. can you see how your concerns have had an effect on the proposal).	proposal as the costs proposed are still too high.

1.7 Shared assets

The MEU notes that TN does not provide advice about whether it provides services to others using the assets fully paid for by consumers.

The MEU therefore assumes that the "shared assets" guideline does not require TN to provide information on shared asset use. If it does, then the MEU assumes that the benefit TN gets from providing these services using shared assets is less than the 1% trigger that the guideline sets as the level at which TN would be required to share the revenues with consumers. As the MEU stated during the development of the guideline, it considers the 1% of revenue trigger is way too high. The MEU expects that the AER will clarify if TN is receiving additional revenue from sharing assets with others and to the amount of revenue is less than the trigger amount

2. Forecasts of demand, consumption and input cost changes

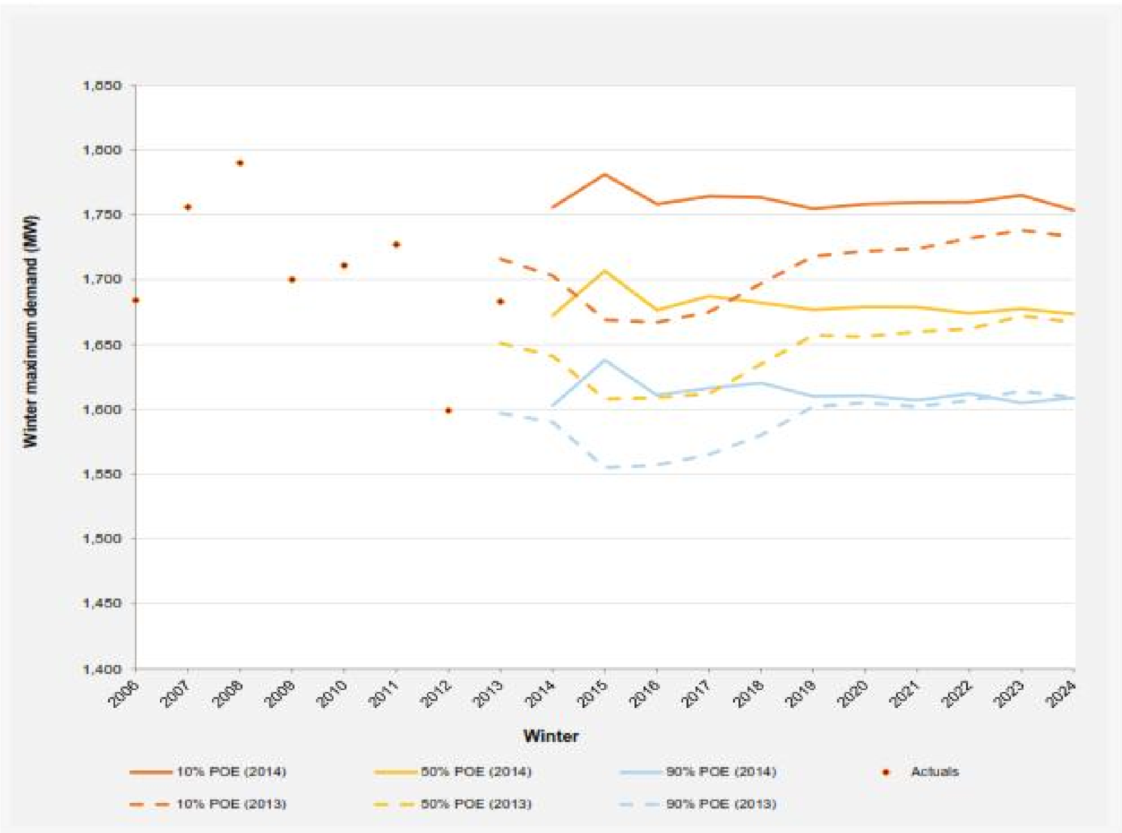
2.1 An overview of electricity (demand and consumption) forecast changes

TN is responsible for augmenting the Tasmanian electricity transmission system to meet increases in demand. To provide a view on the needs for augmentation, TN has developed its own view of what is likely to occur in terms of growth in demand which drives the need for augmentation of the network. TN then notes that its view on demand growth is higher than the growth forecast by AEMO in its 2013 NEFR.

TN comments that it will discuss its forecasts with AEMO in order to harmonise the TN view on growth with the AEMO 2014 NEFR forecasts. However since the TN proposal was prepared, AEMO has released its 2014 NEFR which demonstrates that the 2013 forecast is less than under the 2014 forecast. This is shown in the following chart[6].

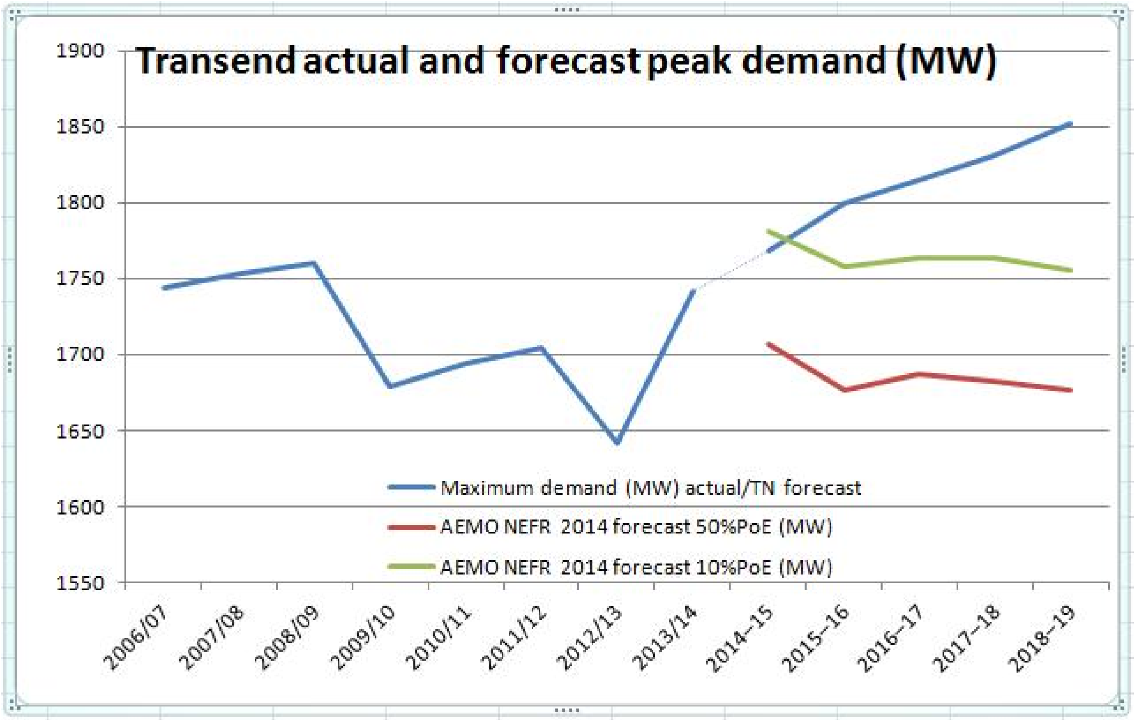
7.4.1 Winter maximum demand forecasts

Figure 24 — Winter 90%, 50% and 10% POE maximum demand forecasts for Tasmania



[6] Figure 7.4.1 is included in the 2014 NEFR for Tasmania.

Despite the 2014 NEFR forecast demand being higher than the demand forecast in the 2013 NEFR, the NEFR 2014 forecast is still lower than that forecast by TN and this is shown on the following chart



Source: AEMO data, TN proposal, 2014 NEFR

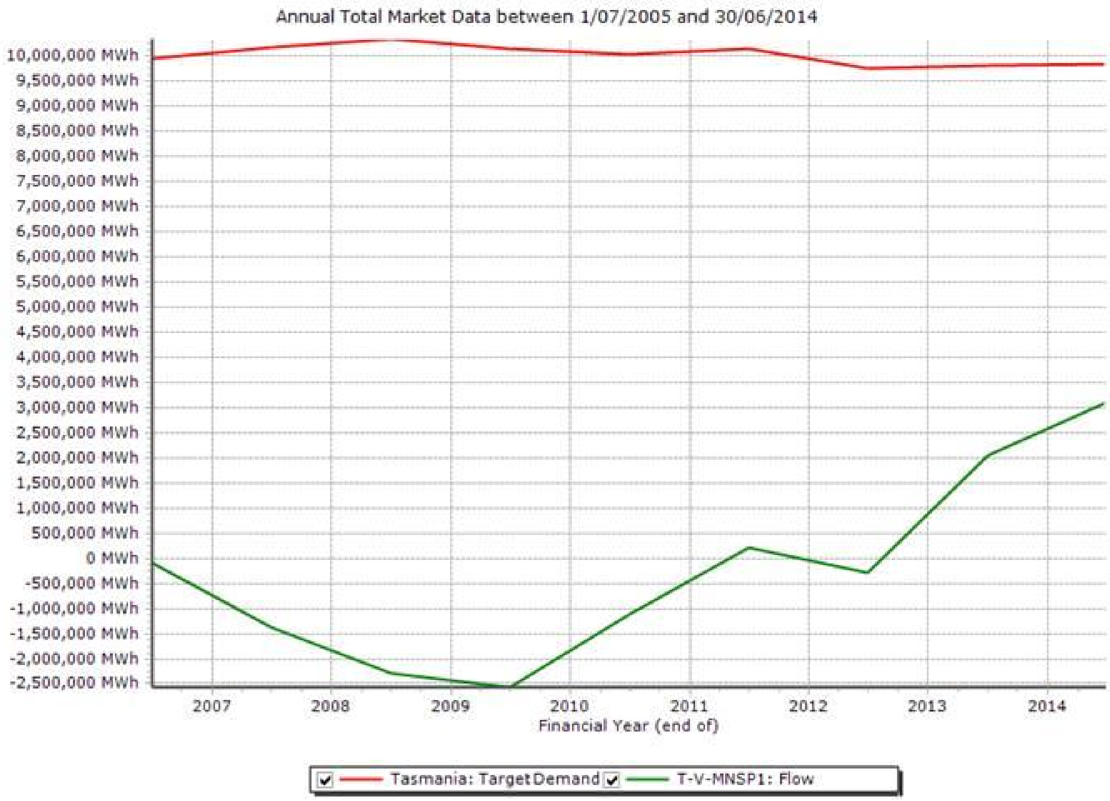
The peak demand recorded in Tasmania was 1753 MW in 2008. AEMO forecast (50% PoE) is that this peak demand will not be exceeded in the next decade. On a 10% PoE, AEMO forecast that the peak demand recorded will exceed this amount in 2014-15 by a maximum of 30 MW (or 1.6%) and thereafter be perhaps only 10 MW more than the 2008 peak. On this basis it should be assumed that the demand in AA3 is most unlikely to exceed the peak demand already recorded.

This provides a prima facie case that there is no need at all for TN to augment its network during the coming period. Equally, the MEU accepts that there may be some very few specific areas in the network that may need augmenting to meet increases in growth in localized parts of the network, although the MEU is unaware of any such cases.

However, it is important to note that in its proposal for the 2009 reset, TN had forecast a considerable increase in expected demand and commenced capital works to accommodate this forecast growth. This means that the network has already been augmented by more than would be necessary to accommodate even the 10% PoE AEMO forecast of demand growth.

On a consumption basis, TN experienced a maximum consumption of 10.34 TWh in 2008/09 year, and AEMO (in the 2014 NEFR) is not forecasting this volume to be exceeded in Tasmania until 2017/18 even under a high growth scenario; the medium growth scenario shows this volume not being exceed in the next decade.

The MEU also notes that the forecasts provided actually deliver an inconsistency. In the Tasmanian network, there is a single large consumption point - the Georgetown terminal of Basslink which delivers supplies to Victoria. The following chart shows the total amount of electricity provided in Tasmania for the past 9 years, and the amount of electricity exported to Tasmania. The difference is the amount used within the state.



Source: AEMO data

When the total production of electricity is reduced by the amount of electricity exported, the decline in Tasmanian consumption shows a massive reduction - from some 12.5 TWh in FY2008 and FY2009 to less than 7 TWh in FY2014. What this signifies is that the usage made by Tasmanian consumers of the transmission network is being masked by the significant amounts of exported electricity. Although some revenue will come to TN as a result of the inter-regional TUoS adjustments commencing in 2015, this will not offset the total and significant cost that Tasmanian consumers will pay on their transmission charges for the privilege of exporting power to Victoria[7].

Overall, what is concerning is that with the reducing consumption (medium and low growth forecasts) and relatively flat demand, the prices for transmission will have to increase per unit to allow TN to recover the revenue that it is forecasting. The MEU notes that TN is forecasting a slightly declining average price path (in constant dollar terms) after a step reduction. With increasing revenue and falling consumption (2014 NEFR medium and low growth forecast) or reasonably flat consumption (2014 NEFR high growth forecast) the MEU cannot see how TN can be forecasting a declining average price path.

The MEU, therefore, is concerned that TN does not explicitly address this issue. Nor does TN set out alternative scenarios based on lower demand forecasts, such that the risks and price impacts on consumers is transparent.

2.2 Escalation forecasts for labour and materials

2.2.1 Wages cost growth

> TN consultants observe that, despite their preference for another measure, the AER has expressed a preference for using the labour price index (LPI). What the regulated firms have all failed to recognize is that the outcome of using LPI has not disadvantaged the regulated firm because consistently, actual opex costs have, over time, been generally less than the regulated allowance. On this basis alone, there is no sound reason for the AER to vary from its present practice of using LPI which is based on independent data to forecast future labour cost changes.
>
> TN appears to have opted for using a labour price index generated by its consultant Independent Economics (IE) which is not productivity adjusted. In this regard, the MEU notes that the AER has most recently used LPI calculations from Deloitte Access Economics (DAE) which were not productivity adjusted but the AER applied improvements in productivity as an explicit adjustment to forecast labour allowances.
>
> A number of firms providing monopoly utilities services consider that the LPI should be adjusted to remove the Waste Services (WS) element from the EGWW sector, to better reflect the EGW sector that it considers it operates in. In previous applications to the AER, firms have used an argument provided by BIS Shrapnel to seek the elimination of the waste services element of the index. However, the MEU notes that TN consultant IE has provided a view that the EGWW index is a good

[7] This is because the IRTUoS only recovers the locational cost of transmission and none of the non-locational TUoS and common services

surrogate for labour price escalation.

The MEU is concerned that in the past forecasts made by DAE have varied from those made by other forecasters. The fact that there are significant variances between forecasts and actual movements (more often in overstating future movements thereby benefiting the NSP) results in a lowering of confidence for their use for this reset review (see section 2.2.3 below).

For internal labour cost escalation, TN has opted for this labour cost element to be escalated using the TN employee agreement. The MEU considers this is inappropriate. The MEU does not consider that a regulator should adjust costs to relate to future cost changes that have been negotiated by a single firm. This does not necessary reflect an efficient outcome and provides a bias towards higher labour costs than might occur under a more independent approach.

For example, if the AER allows the enterprise agreement to be used to set the future costs, this provides the negotiating team for employees with a clear signal that whatever labour cost movements are agreed will be rolled into the next regulatory decision. If this occurs, the firm has no strong driver to negotiate the lowest possible price for labour. If the AER uses an independent assessment of expected labour price movements, then the firm has a driver to negotiate a lower price for labour as this would provide a benefit to the firm. It does not lead to an efficient outcome where both parties to a negotiation are aware that whatever is agreed the cost will be borne by a third party.

The MEU considers that:

- Capex and outsourced labour costs should be adjusted for forecast movements in the DAE construction LPI;
- TN direct labour costs should be adjusted for forecast movements in the DAE EGWW labour LPI, and
- Productivity improvement be stated as explicit adjustments to the cost allowances

This approach maintains consistency with previous AER decisions and provides regulatory certainty of approach. In any case, TN has not provided adequate reasons for change from AER practice in its proposal. It is also consistent with the AER's Expenditure Forecasts Assessment Guideline that specifically refers to an explicit productivity function to apply to forecasts of opex.

2.2.2 Materials cost growth

TN provides a report from CEG giving a forecast of the movements in certain materials, the expected movements in the CPI and $A-$US which are both used to adjust the materials prices to reflect local real costs.

The MEU is concerned that the CEG forecasts essentially imply that material costs will rise over the forecast period. This view appears to be at odds with views form others. For example, in appendix 1 the MEU provides a report of the Bloomberg view that materials used in the electricity industry are likely to fall rather than increase. This divergence of views needs to be closely assessed by the AER.

Further, what TN (and CEG) does not do is provide the weighting of each material element to its mix of materials and demonstrate that the weighting is reflective of the actual mix of the various elements that comprise the final adjustment to the cost of materials.

The MEU is concerned that forecasts of materials cost movements are based on assumptions that are inappropriate for the use to which they are put. For example,

- If the forecasts are to be used for budgeting purposes then they will include a degree of conservatism. There is no indication as to the degree of conservatism that has been used in their development
- How accurate and robust have these forecasts been in the past? Has there been any assessment to compare the forecasts with actual costs to identify the degree of accuracy implicit in the forecast?

The MEU considers that forecasting error can be avoided and addresses this in section 2.2.4 below.

2.2.3 Property escalation

TN has assessed the movements in property prices and set escalation rates for the land it owns and for its easements. The MEU has no problems with using this approach for the value of the land that TN owns but it has considerable concern with applying this approach for the value of easements.

The value for easements does not reflect ownership of land. As the ACCC allowed in 2002 in its decision for the costs of easements in Victoria when assessing the value of easements held and again later in 2008 by the AER[8]

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[8] The AER assessment for ElectraNet was successfully appealed in the Competition Tribunal and adjusted

when assessing the valuation of easements acquired by ElectraNet, the cost of easements were seen not to be related to the cost of land but reflected the cost for landowner compensation and the transaction costs involved in the development of the easement.

This means that the cost of the easement is based on

1. The payment of a fixed sum to the land owner. A fixed payment made to a land owner for the easement would have been a "once off" amount and not necessarily related to the value of the land over which the easement was sought. In many cases, the land over which the easement is granted is still used by the land owner for the same purpose it was originally used. As a fixed dollar payment, this means that the carry forward of the cost in the Regulatory Asset Base (RAB) is more closely related to the cost of money rather than the cost of land. On this basis the compensation element of the easement carry forward value would be related to CPI rather than to the cost of land.

2. The costs of development of the easement. Easement acquisition and transaction costs are not related to real estate value but include the labour costs in detailing, surveying and negotiating the acquisition. This means that the carry forward of the cost in the RAB is more closely related to the cost of labour and CPI than to the cost of land.

The MEU has noted that in the past the AER has allowed for escalation of easements based on the value of the land over which the network has the easements rights. The MEU considers that the AER has been wrong in this and should apply an approach more reflective of the basis on which the easement costs are made, that is, at historic costs with adjustments for CPI and a return on the investment at the regulated rate.

The MEU considers that the AER should rectify its earlier approach and in future apply an escalation methodology for easements based on the way the costs are incurred rather than continuing with a flawed methodology based on using land escalation as the basis for adjusting the value of easements. The MEU considers that these costs should be capitalised and then escalated at CPI.

2.2.4 Labour and material forecasting inaccuracies

As part of the analysis for the decision to use LPI in lieu of AWE (see section 2.2.1 above), the AER provided a comparison of the past performance of Deloitte Access Economics (DAE) and BIS Shrapnel (BIS) in forecasting actual labour movements[9].

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[9] See for example table C2 in section 3 of the AER draft decision on the Multinet gas application

This data is quite fascinating and from it the AER concludes that the LPI forecasting by DAE is more stable and exhibits less volatility than does BIS forecasting and so the AER considers the DAE forecasting is preferred.

What the AER does not do is to assess the actual accuracy of the forecasts over time. For example, the DAE forecast for EGW made in 2007 for year 2010/11 shows a small under-run compared to the actual LPI. Yet these forecast errors are compounded – the forecast for 2010/11 is the compounded increase of all the previous years of data. When compounding is implemented, the actual increase in LPI for 2010/11 based on movements from 2007 implies labour costs in 2010/11 were 24% higher than in 2007. The DAE forecast for the same period shows an increase of 26% (the BIS increase is nearly 29%).

Further, the errors between the actual values and the forecasts show a consistent overestimation of future LPI values. The number of times the forecasters underestimated the actual LPI is 25% whereas the overestimates comprise 60% of the forecasts – the balancing 15% is where the forecasts were accurate. On this basis the forecasters are likely to overestimate the LPI 4 times more than they get it right and underestimate it 2 times more than they get it right.

These actual calculations and comparisons show that the forecasts are biased towards overestimation and so impose increased and unnecessary costs on consumers.

The MEU considers that the AER should also review the accuracy of material forecasts over time to ensure that the forecasts are not biased in a similar manner.

The MEU again considers that the AER needs to find another approach to making adjustments to capex and opex allowances to reflect future movements in input costs. The current approach can cause considerable harm to consumers and could, in the future, cause harm to regulated firms through underestimating future price rises.

In previous submissions, the MEU and its affiliates have suggested that forecasting inaccuracy could be overcome by the use of an escalation factor unique to the energy market which the AER would generate annually for adjustments to allowed revenues rather than use the CPI.

The decision of the AER to not use such an approach is strange. The argument put by the AER was that allowing for annual adjustments to allowed revenues by using the CPI provided some certainty for consumers and regulated firms and using an escalation factor different to

CPI would introduce uncertainty. This issue of "certainty" for consumers and regulated firms is becoming less important with the changes that are being made in the regulatory approach. For example

- For revenue cap decisions, (which currently will apply to nearly all regulated networks) there are frequently massive adjustments in tariffs because of large swings in current year revenues caused by under or over recovery of the allowed revenue in the previous year. In the case of transmission networks, these year-on-year swings to adjust for over/under recoveries are exaggerated by the inclusion of inter-regional settlement residues and the new inter-regional TUoS adjustments being introduced in July 2015. That MEU members report seeing transmission tariffs vary year on year by as much as 20% exemplifies the lack of certainty introduced by these impacts

- The AER is introducing a variable cost of debt into the development and this will result in the actual WACC varying from the WACC used to develop the forecast revenues Whilst these variations in the WACC are expected to be relatively small, they will be significantly magnified by the application to the RAB, resulting in considerable changes in revenue allowed compared to that forecast at the reset.

- The AER already permits revenues to be adjusted to reflect variations in the actual CPI compared to that forecast. The annual movements of a network specific inflation adjustment are not expected to be significantly more volatile than those of the CPI.

If swings of this magnitude can occur without using an input cost adjustment index, then the AER argument fails to be legitimate. The MEU is of the view that using an industry specific escalation index would reduce the inaccuracies inherent in the current AER approach and should result in a more equitable outcome for both consumers and networks.

Many industries use cost input adjustment indices that are not the CPI to reflect the industries' special needs, so a decision to use a more accurate approach that allows for variation in input costs would not be ground breaking in the least.

The application of an Efficiency Benefit Sharing Scheme (EBSS) also requires a more accurate initial forecasting approach. If costs are over-forecast, for instance, by using more global estimates of costs, then consumers pay twice – once during the regulatory period and again through the EBSS mechanism. Efficiency incentives only achieve their objectives when the initial forecast is optimised.

3. WACC

3.1 About the weighted average cost of capital (WACC)

There was considerable disquiet about the regulatory framework which saw massive increases in the cost of providing network services. As a result, there were a number of rule changes proposed to address what was seen as a biased outcome favouring network service providers. Indeed, there were significant changes made to the rules and which provided the regulator with greater discretionary powers. Contemporaneous with the rule change process, the energy Laws were also changed to moderate the ability of network owners to appeal AER regulatory decisions.

It was during this period that the Chair of the AEMC, Mr John Pierce, is reported as stating[10]:

> "You've got to have the right rate of return. The first question is, what's the minimum rate of return necessary to attract funding so people will invest in the sector. Secondly, we want people to operate efficiently so what we need is an efficient benchmark rate of return… we want them to try and beat it so the shareholders get the benefit of it, so that next time around it can be shared with customers.
>
> ''But if they don't … then you also want the shareholders to suffer … if I'm inefficient, I want the shareholders to carry that risk, not customers."

The MEU supports this view.

Over the period from late 2012 to the end of 2013, the AER devoted considerable resources to developing a rate of return (weighed average cost of capital - WACC) guideline that reflected this view provided by Mr Pierce. As part of the process undertaken by the AER, consumers and network firms provided considerable input into the AER process. The outcome was not one which either consumers or network firms agreed met the needs of each party. Despite this, the MEU considers the outcome is better than the previous approach used by the AER, the ACCC and the jurisdictional regulators.

In particular,

- The network firms have stated a view that the AER approach to the development of the return on equity results in a lower outcome than they consider necessary[11]. Despite the concerns expressed, the network

[10] "High power rates: it's a poles and wires story", SMH June 12, 2012
[11] It is obvious that the recent low yields for 10 year CGS (used as the risk free rate) has raised concerns with all network owners as they provide considerable argument to replace the AER's "on the day" approach with a long term average risk free rate (going back over 130

firms were not able to explain why, if they were getting a lower return on equity than was considered appropriate, there was still a drive from potential acquirers of network assets to want to invest in the assets at a premium to the RAB.

- Consumers have noted that the market parameters (equity beta and market risk premium) have been set on the "high side" of what the market indicates are the realistic values for these, thereby providing a benefit to the networks.

- Consumers considered that the approach on return on debt did not reflect the actual costs of debt that the network firms were seen to incur. Further, even when the networks do secure lower cost debt than allowed by the AER, this benefit is retained by the networks and is not passed onto consumers "next time around" as implied by the observation of Mr Pierce.

The amount of time and effort dedicated to getting a better approach to the WACC calculation by the AER, consumers and networks should have resulted in a large degree of acceptance of the outcome, but this is not the case. Consumers have consistently seen network firms argue that the AER decision on the WACC development is flawed and want an outcome that is more attractive to the network owners. IN contrast, the desire for acquisition of network assets **at a premium to the value of the assets**[12] reflects a view by investors that the rewards from ownership are greater than implied by the network firms even with the flaws identified in the regulatory framework by them.

The purpose of the AER in devoting considerable effort to getting stakeholder input was to reduce the uncertainty about how the AER would address the issue of setting a regulatory rate of return given its new discretionary powers. What is now apparent is that the networks consider that the AER guideline on rate of return is merely a starting point for seeking better outcomes for the networks.

As a general premise, the MEU accepts that the AER rate of return guideline was developed as a package and sought to balance competing elements to

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years). This provides a higher value for the risk free rate of some 250-300 bp than the current levels experienced. As a result some network owners have argued that either the long term average 10 year CGS should be used as the basis for the CAPM calculation, or that higher levels of market risk premium should be used to accommodate what they consider to be a disparity in the calculations for the equity and debt components of the WACC that arises from a low risk free rate

[12] For example, the offer by CKI for the Envestra assets values Envestra at a premium of 50% over the regulated asset base (RAB) and the acquisition of a holding in DUET by Spark Infrastructure values DUET at over a 30% premium to the RAB. It is important to note that these acquisitions occurred after the fall in the demand for electricity and gas which in other markets might have implied a lower premium

provide an equitable outcome. On this basis, the MEU accepts that the guideline should be implemented in its entirety and imposed on TN. Failing this, then all aspects should be opened for re-assessment, in a process that engages consumers and other affected stakeholders as much as NSPs. Any variations from the guidelines should be a matter of consultation with all stakeholders to demonstrate the so-called benefits, not a negotiation between the AER and the NSPs.

3.2 The WACC for TN

TN has advised in its proposal that it has applied the AER guideline on rate of return. Based on its assessment of the guideline, TN seeks a return on equity of 8.7% and a return on debt of 6.84% giving an overall rate of return of 7.58%. These values are based on a risk free rate of 4.11%.

TN has also noted that it accepts the AER guideline in relation to the transitioning program proposed by the AER to convert the cost of debt from an "on the day" assessment to one based on a trailing average approach to set a cost of debt.

In its application, TN observes (section 10)

- That it has received advice from an independent expert (SFG) that it could argue for a higher rate of return on equity of some 10.71% which is some 200 bp higher than that which TN has calculated from the AER guideline.
- It has advice that gamma - the assessment of imputation credit impact on tax - could be set at 0.25, a value that has applied in recent regulatory decisions.

Despite this advice, Transend has elected to follow the AER guideline because (page 107)

> "… we must also consider the impact of a higher cost of equity on our customers. We are particularly mindful of the commercial pressures currently facing our customer base in Tasmania. A balance must be struck between the objective of ensuring that the true cost of equity is recognised in our revenue allowance, and the need to establish a price path that is sustainable for our customers. In weighing these considerations, we propose to adopt the parameters values identified by the AER in its Rate of Return Guideline and explanatory statement."

The MEU acknowledges this decision by TN although the MEU still has reservations that the AER guideline is one that leads to a weighted cost of capital that is still excessive when considering the risks faced by monopoly networks.

The MEU also notes that since the TN proposal was developed the risk free rate has fallen (in early August 2014) by some 60-70 bp and that the cost of 10 year corporate bonds has also fallen considerably by over 100 bp (RBA index). Implementing these reductions in the AER guideline would result in a weighted average cost of capital falling by over 80 bp to about 6%.

3.2.1 Credit rating

TN accepts the AER credit rating of BBB+ even though it acquires credit from its owner which acquires debt at AA+ credit rating rates. This acceptance of the AER guideline provides TN with a significant benefit

The MEU notes that the current cost of debt that TN incurs (as extracted from recent Annual Reports) is a little lower than the cost of debt that TN is seeking under the AER guideline. The MEU considers that its owner will, through its Tasmanian Public Finance Corporation - TasCorp, be able to provide lower cost debt to TN than it currently does recognising that the cost of debt has fallen considerably in the 12-18 months since the costs for debt were publicly declared most recently (ie in the Transend annual report for 2012/13 financial year).

On this basis, TN could reduce its rate of return considerably, especially in light of the professed reasons for not seeking a higher return on equity.

3.2.2 Equity beta

The final decision by the AER on the rate of return guideline calculates a current equity beta of 0.7 to be used based on evidence available to it late in 2013. TN has used this value in setting its return on equity. The range of equity beta values assessed by the AER was that it lay between 0.4 and 0.7; thus the decision of the AER sets a value at the very top of the credible range

Subsequent to the final decision on the guideline, AER consultant Professor Henry provided his assessment of the value for equity beta. His advice was that the value lies between 0.3 and 0.8 with an average from the individual firms of 0.5223 and a median value of 0.3285. This work by Prof Henry is primarily focused on the actual equity betas of the network firms operating in Australia and therefore this provides a clear view of what the values are under Australian conditions. This is particularly important as the AER had elected to use the high end value for equity beta partly based on a view that equity betas from overseas gas transportation firms implies a higher value than occurs in Australia.

The MEU notes that it had previously provided a view that the average of the range for equity beta should be used - a view that the AER rejected.

The new information from the AER consultant (Prof Henry) provides a view that the range of values for the equity beta is wider than that used by the AER in the guideline development, but that there is a clear indication the benchmark efficient entity would have its equity beta closer to the median value than the average value - a median value highlights that the most common value for equity beta for Australian networks recognising the uniqueness of the Australian energy market and its regulatory environment.

The MEU notes that TN, despite some reservations, has used the AER calculated equity beta of 0.7 and uses this in the S-L CAPM calculation for return on equity. When setting the allowed return on equity for TN, the MEU considers that the AER should use a value that is consistent with the later work for Prof Henry and reduce the value of equity beta to a lower amount.

3.2.3 Corporate bond rate

TN proposes that the debt be acquired on a 10 year corporate bond series rated BBB+ from the RBA. The MEU notes that TN has used the transitioning approach outlined in the AER guideline to develop the cost of debt. The MEU supports this approach.

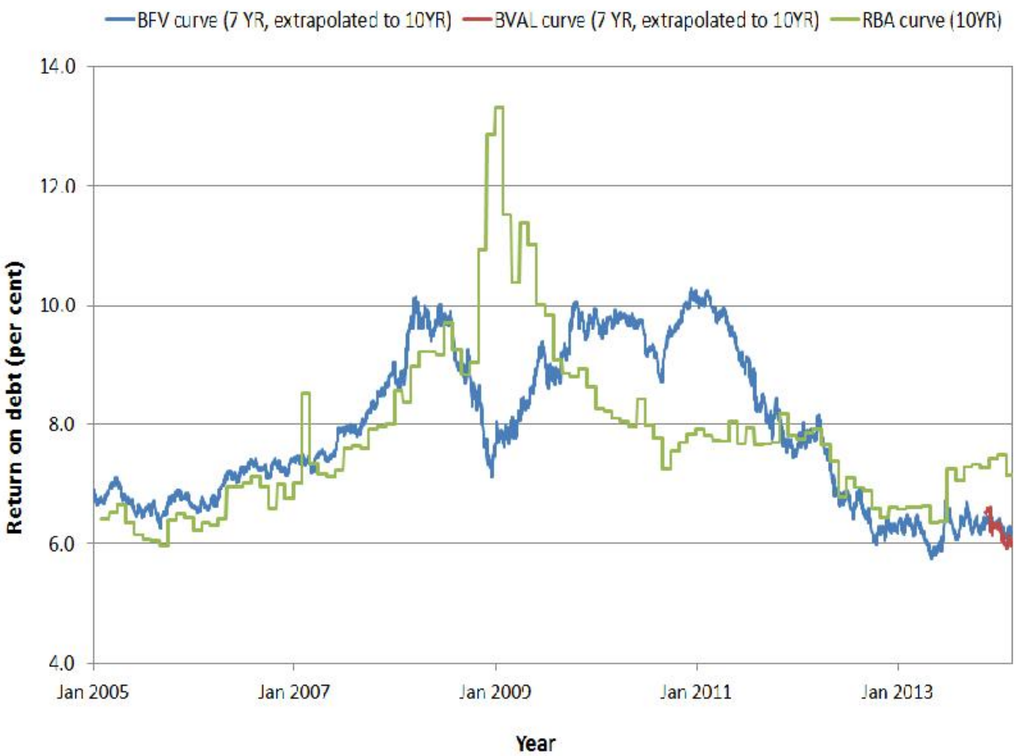
However, the MEU also notes that TN has elected to use just the corporate bond data series developed by the Reserve Bank of Australia (RBA). Whilst in theory the RBA data series would be preferred over less transparent methods of providing such data the MEU notes that the RBA data has its own shortcomings

In April 2014, the AER sought stakeholder views on the best approach to assessing the source of data to be used for the development of the return on debt. The AER points out that both of the series under review (that of the RBA and of Bloomberg) both exhibit shortcomings to the criteria the AER has identified as optimum for assessing the cost of debt based on corporate bonds. Specifically, the RBA currently only publishes data from the last day of the month requiring interpolation to generate a daily series and Bloomberg only publishes data for 7 year bonds, requiring extrapolation. Both require interpolation to identify a data series for BBB+ rated bonds. Interpolation and extrapolation both introduce the likelihood for error.

It was this in mind that the MEU recommended that the AER/ACCC should develop its own series to replicate what the cost of debt is for a pure play energy network. An AER/ACCC series could be tailored so that one of the main criticisms of using corporate bonds to set the cost of debt is overcome - that even for firms with the same credit rating, the cost of debt varies with the core business of the firm and that regulated energy networks can acquire debt at a lower cost than other firms with less secure cash flows even though they have the same credit rating.

In the figure 1 provided by the AER in its Issues Paper discussing the different data series, there is no doubt that using the trailing average approach in its entirety would have provided a clear benefit to TN. It is less clear whether the RBA data series provides a better outcome for TN than using the historical data from the Bloomberg Fair Value. Certainly an immediate move to the trailing average is not possible with the new Bloomberg data series BVAL.

Figure 1 Comparison of return on debt estimates



Source: AER analysis.

Note: The Bloomberg data has been extrapolated from an underlying seven-year curve to a ten-year term by adding a fixed term spread of 30 basis points. The addition of a fixed spread represents a simplification for illustrative purposes, but the magnitude of this spread reflects that applied in recent AER decisions.

The MEU can see why TN might have settled on using just the RBA data series as it appears that the RBS series shows a premium to the BFV curve. Whilst there appears to be a clear differential of up to 100 bp between the RBA and Bloomberg series, the MEU notes that the RBA series has fallen dramatically in the months since the figure was developed and now shows a value below 6% - the MEU does not know the equivalent values for the BFV and BVAL but assumes these have fallen also.

Accepting that the AER has not commenced developing its own data series, for this review external data providers must be used and the data extrapolated/interpolated to derive the cost of debt for TN. The MEU considers that both sets of data should be used and averaged as recommended by the Competition Tribunal when there is more than one set of data available.

3.2.4 Value of imputation credits

TN has accepted the AER guideline in relation to the value of imputation credits (gamma). The MEU supports this decision by TN as the AER devoted considerable effort to carry out a better assessment of gamma during the Better Regulation program. It was with this better information that the AER concluded that gamma should be set at 0.5 essentially reflecting a payout ratio of 0.7 (as previously used by the AER and the Competition Tribunal) and a utilisation rate of 0.7[13].

3.2.5 Conclusions

The MEU considers that assessing each of the various parameters implicit in the rate of return in isolation has resulted in networks being granted much higher revenues than were needed to provide the service. The AER has assessed the various parameters in a holistic manner and by doing so has provided a balanced view recognising that it is probable that errors have been made in setting each individual parameter.

As each of the various parameters can impact other assessments made under the rate of return guideline, the MEU supports using the guideline in its entirety rather than "cherry picking" aspects which favour one stakeholder over another. On this basis the MEU agrees with the AER and TN that gamma should be 0.5.

3.3 AER questions on WACC

	AER questions	**MEU response**
1	Do you have any comments on the businesses proposed departures from our guideline?	Yes. As noted above, the MEU considers that the rate of return guideline reflects a balance of competing aspects and should be taken as a holistic view of the entire approach to identifying a reasonable rate of return for regulated networks with a guaranteed income.

[13] In contrast a utilisation rate of notionally 0.35 was used by the Competition Tribunal as an appropriate estimate in its previous decisions

		To "cherry pick" elements out that do not provide the best possible outcome for networks and to institute new approaches to the setting of these specific elements defeats the purpose of having a holistic approach. TN appears to have followed the AER guideline appropriately. The only concern the MEU has with the TN approach to WACC is that rather than using the RBA bond rate data exclusively, the MEU considers that the average of RBA and Bloomberg FVAL should be used to set the cost of debt.
2		
3	Do you consider the value in the AER's guideline and Tasnetworks proposal (0.5) or TransGrid's proposal (0.25) provide a more appropriate approach to estimating the value of imputation credits?	The MEU supports the AER approach to setting "gamma". The MEU notes that TN has used the same value for gamma that is in the AER guideline. As noted above, the MEU considers that the rate of return guideline reflects a balance of competing aspects and should be taken as a holistic view of the entire approach to identifying a reasonable rate of return for regulated networks with a guaranteed income.

3.4 Pass through events

The use of "pass throughs" is a mechanism for the regulated entity to reduce its risk by passing these onto consumers. Regulators have been inclined to accept this approach as they (rightly) fear that an allowance in the costs to accommodate this risk might be too high reflecting the likelihood of exogenous low probability high impact events.

The recent decision by the AER to allow a pass through of costs above that covered by insurance resulting from the Victorian bushfires implies that this was a low probability high impact event. There is a concern that the event itself might not be exogenous, and the outcome of the current court case might determine if this is the case.

In the current Rules there are defined elements where the "pass through" of actual costs is permitted. In particular TN considers that a terrorism event should be a pass through along with an insurance cap event and a natural disaster event. The AER has previously accepted these as legitimate bases for pass throughs and the MEU accepts these should continue. The MEU notes that the definition of these pass throughs is the same as the AER has previously accepted

The MEU considers that each NSP should provide adequate insurance (either external or self insurance) to cover the bulk of the likely risks the NSP faces. Where the cost of such insurance is too high relative to the likelihood of the event occurring, the MEU accepts that such a risk might be transferred to consumers as balancing the cost premium for managing this risk would be excessive compared to the likelihood of it occurring. However, the application of this general policy should be carefully considered if the event is found to be as a result of negligence of the business and its management. These risks should not be passed onto consumers.

The MEU considers that it is appropriate for consumers to take a risk where there is the likelihood of high impact low probability event which is beyond the ability of a network to manage without excessively high insurance premiums.

Where the network has the ability (and responsibility) to take action to mitigate the risk through good management, such risks should be carried by the network. The necessary resources are made available to networks through the opex and capex allowances to institute this good management and precluding the need to transfer the risk to consumers.

It is important to recognise that in a competitive environment, the ability to pass through any of these costs to consumers is not possible, and firms have to absorb the costs (either through insurance or directly) of any exogenous impact, regardless of whether they are high impact low probability or not. Because there is the ability to pass through such costs to consumers by regulated NSPs, the AER must recognise that with this transfer of risk there needs to be a compensating reduction in the equity beta to reflect the reduced risk faced by NSPs.

4. Depreciation

4.1 Early retirement of assets

TN implies that some of its assets might need to be replaced earlier than their age might indicate (ie that the asset is not fully depreciated) as a result of condition monitoring, where early replacement is warranted to prevent the asset failing whilst in service. This is in addition to the maintenance of the average replacement program TN implemented in AA2 indicated by TN in its capex proposal. Equally, with the reduced loading on many of TN assets, there is an increased expectation that existing assets will be "used and useful" for a longer period than might be expected based the "engineering life" used to set the depreciation schedule

Early replacement has the impact of TN not only obtaining recovery of its return of capital earlier than might be planned, but also for consumers incurring higher costs. This is due to replacement assets having a higher depreciated cost than the assets being replaced and therefore the return on capital for these assets will be higher than might be the case if TN had ensured the assets lasted for at least the expected life.

In the reverse of this situation, TN has the incentive to replace assets as soon as they are fully depreciated, rather than retain in service assets that are fully depreciated but are still used and useful. This particularly applies where the return allowed on assets (allowed WACC) is higher than the actual WACC the NSP incurs.

This driver is unique to the building block approach to revenue setting in that a fully depreciated asset does not attract any return (WACC times zero is zero), whereas replacing a written off asset does attract a return. As opex is recovered at cost under the building block, the profits for a regulated business come only from the return on assets. In a competitive business having written off an asset is seen as a positive if the asset is still used and useful as the costs for production are lower.

In a competitive environment, the price of an article produced tends to be based on the short run marginal cost in order to be competitive. The import of this is that the price used for sale does not recover the long run marginal cost, which includes for the depreciation of the assets used to create the product. It has been observed by many businesses that their recovery of depreciation is usually less than the actual investment made, and that this observation is predicated on the nominal value of depreciation as used by the ATO. In a regulated environment the “real” value of depreciation is incorporated into the building block, enhancing the costs to consumers.

Bearing in mind that competition does not appear to allow businesses operating in a competitive environment to in fact recover depreciation (either nominal or real values) the AER must be particularly aware of the potential to game the depreciation of assets.

In the past, the MEU members and members of MEU affiliates have seen electricity supply authorities continue to use assets long after the asset has been written off financially. Member experience is that the technical life of many assets is quite a bit longer than the average used to financially depreciate the assets in the building block approach. The application from TN supports this view in that TN has advised that some assets have continued to operate satisfactorily well beyond their assessed economic life. Physical life of an asset is related to many more aspects than just time. Assets lightly used and well maintained will generally be useful longer than the expected asset life. The care used in manufacturing and the basic design parameters also greatly impact on asset longevity.

Thus, MEU has a deep concern that assets still "used and useful" will be taken from service by TNSPs as the TNSPs no longer get any return for them. They can then be replaced with new assets on which they do get a return, yet when assets appear to need early replacement, the NSP is permitted to do this without any penalty being applied.

4.2 When should assets be replaced?

Whilst the ability of TNSPs to secure new sources of funds has been seen not to be a major issue, competitive businesses tend to have more challenges in raising new sources of funds. Because of this, competitive businesses consider that there has to be a strong financial justification to inject capital rather than continue to have higher opex. The approaches vary between companies but to justify discretionary capex, the opex savings must recover the capital required usually within 1½-3 years.

It is of concern to consumers that TNSPs do not use a financial model (such as a payback approach) to justify replacement of an asset, relying more on time based approach supported by physical asset management approaches, such as condition monitoring. The MEU agrees that physical asset management must be a standard tool for identifying when an asset requires replacement, but we also believe that such asset management must include a financial tool to address the commercial need for asset replacement.

The AER should require TN to incorporate a financial tool into its asset management program to identify when it is commercially sensible to replace an asset, rather than use physical asset management alone.

In addition, the MEU is concerned about the emergence of ‘condition monitoring’ as a basis for replacement capex, and particularly as it seems to be a growing as a driver for this replacement. As a principle, condition monitoring may have some value. However, the actual practice, including the criteria used for replacement versus repair needs additional scrutiny, especially when it is associated with a sudden resurgence in this component of capex (albeit hidden by reductions in other aspects of capex).

4.3 New and revised asset classes

TN has proposed the introduction of a new asset class based on communication assets and has revised the pre 2009 asset valuations for transmission and substation assets.

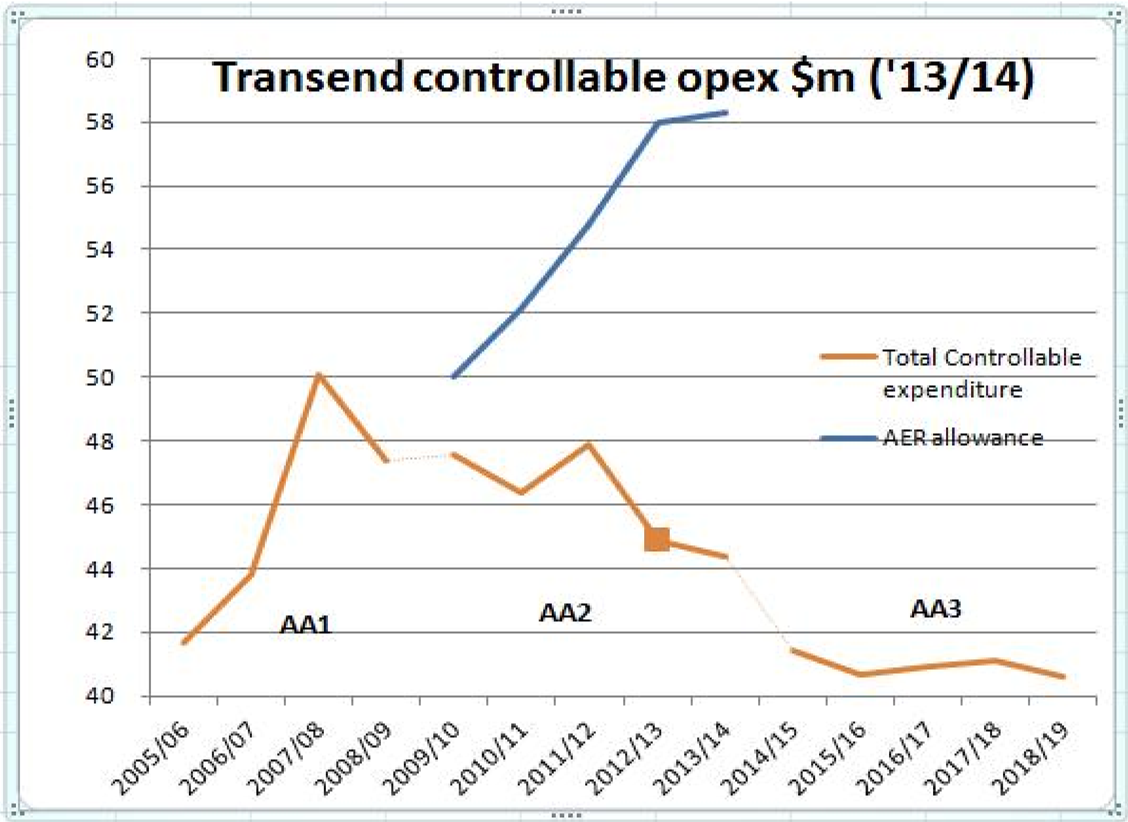
The MEU does not have a problem in principle with introducing a new asset class for the communication assets providing the expected lives of the assets is realistic.

The MEU acknowledges the decision to review the pre 2009 assessment of asset lives and the decision to extend the life of these assets. The MEU notes that this reflects the practices seen in the competitive environment

The AER has advised that it intends to use forecast depreciation as the basis of the roll forward model for the RAB. The MEU considers that changes to the depreciation schedule should be assessed in light of the impact the use of forecast depreciation will have on the RAB.

5. Opex

A view of the trend in controllable opex costs in the current period (AA2) highlights that TN after exceeding allowances in AA1, it sought a massive increase in opex for AA2 which it failed to use.



Source: TN applications, AER decisions

In addition to a downward trend in opex, what the chart shows is the "game" played by TN at the last reset. The forecast costs for the base year of the regulatory period for AA1 is consistent with the AER allowance for the first year of the current period AA2. In fact, the actual opex for the last year of AA1 was lower than the base year and this same level of opex continued in the first year of AA2; opex continued a general downward trend throughout AA2 despite the massive increase in opex allowed.

The base year opex for AA3 is identified by TN as the opex in the last completed full year - in this case 2012/13. At a high level, it is clear that TN has identified opex savings that are continuing to deliver benefits and proposes that the allowed opex for AA3 be even less than incurred in the base year. TN identifies that the reduction comes from efficiency gains and from savings from incorporating the activities of Transend with distribution network service provider Aurora.

The high level assessment would indicate that TN has used the base year costs as a starting point and identified more savings that reduce the opex needs for AA3. The MEU applauds this approach by TN.

The use of the revealed cost approach is predicated on the assumption that current actual costs are near the efficient frontier and that a continuous improvement program will keep costs near the efficient frontier. The historic performance of TN is a far cry from being at the efficient frontier.

The partial productivity comparisons developed by TN consultant Huegin Consulting Group for the TN base year performance generally indicate that TN is not at the efficient frontier and in many cases is one of the least efficient

The MEU has a problem with the benchmarking work by Huegin as it only focuses on the performance of the few Australasian electricity transmission networks although it does introduce the performance of some distribution networks in some of its comparisons. Where the benchmarking is lacking is in not integrating overseas comparisons nor integrating comparisons with capital intensive firms operating in competitive markets. By comparing with just a few firms that were spun out of government owned utilities less than two decades ago and which continue to be monopolies after direct government control does not provide a sound basis for identifying the efficient frontier for operating costs.

Huegin comments on this issue in page 46 of its report (Transend appendix 05) where it states

> "The variability in conditions in Australia and small sample size makes benchmarking through straight, in-year comparison difficult."

The MEU concurs with this assessment.

In particular, the MEU has great difficulties with opex being compared to RAB which is a measure used widely by Huegin in its comparisons, especially where RAB (as it is in network regulation) is continually increased to reflect replacement capital costs under the depreciated replacement cost (DRC) concept[14] and without any optimisation included. RAB based assessments are also massively distorted by when significant capex is made in the networks - this is particularly important when comparing government owned networks as they have lesser constraints on raising capital than privately owned networks.

Other than with regulated monopolies, the use of the DORC methodology for assessing the value of assets is little (if ever) used and therefore its use precludes comparisons being made with other capital intensive operations.

[14] DRC is the basis of the roll forward model used by the AER. It replaces the previously used Depreciated Optimised Replacement Cost (DORC) approach as the Rules no longer include for optimisation that was required under the National Electricity Code

Because of this, the MEU considers that RAB based cost comparisons must be treated with extreme caution

The MEU also notes with concern at the significant reductions in opex that TN has been able to implement, apparently with considerable ease. If TN was operating at the efficient boundary, it would face considerable difficulties in reducing its costs, yet the change that has occurred over the past few years indicates that the reductions have been relatively easily achieved.

In its report on the base year opex efficiency assessment (Appendix 06) Huegin concludes its report with (page 17):

> "Huegin's analysis of Transend's 2012/13 financial year opex has found that it compares favourably in the context of the historical performance and also relative to the broader industry. In particular, Huegin found:
>
> 1. Transend benchmarks well, given its unique circumstances (see previous Huegin benchmarking report) within the industry;
> 2. Transend has decreased opex in the current period - to the point where the proposed base year is similar to the level of expenditure in the previous period base year (FY07)
> 3. Transend has achieved a decrease in opex during a period where the industry (the five TNSPs) on average has experienced an increase in opex.
>
> Given that the 2012/13 year is the most recent audited financial year and also reflects the latest year of a period of deliberate opex reduction, Huegin concludes that it is an appropriate base year for the purposes of forecasting future opex."

Whilst the actual performance of TN in 2012/13 shows it incurred the lowest opex since 2006/07 would support this view of Huegin, the MEU notes that TN is forecasting lower costs for the new period (AA3) than were incurred to date. This clearly shows that the base year cannot be considered to be the most efficient and therefore doubts are cast on efficiencies of the forecasts for AA3.

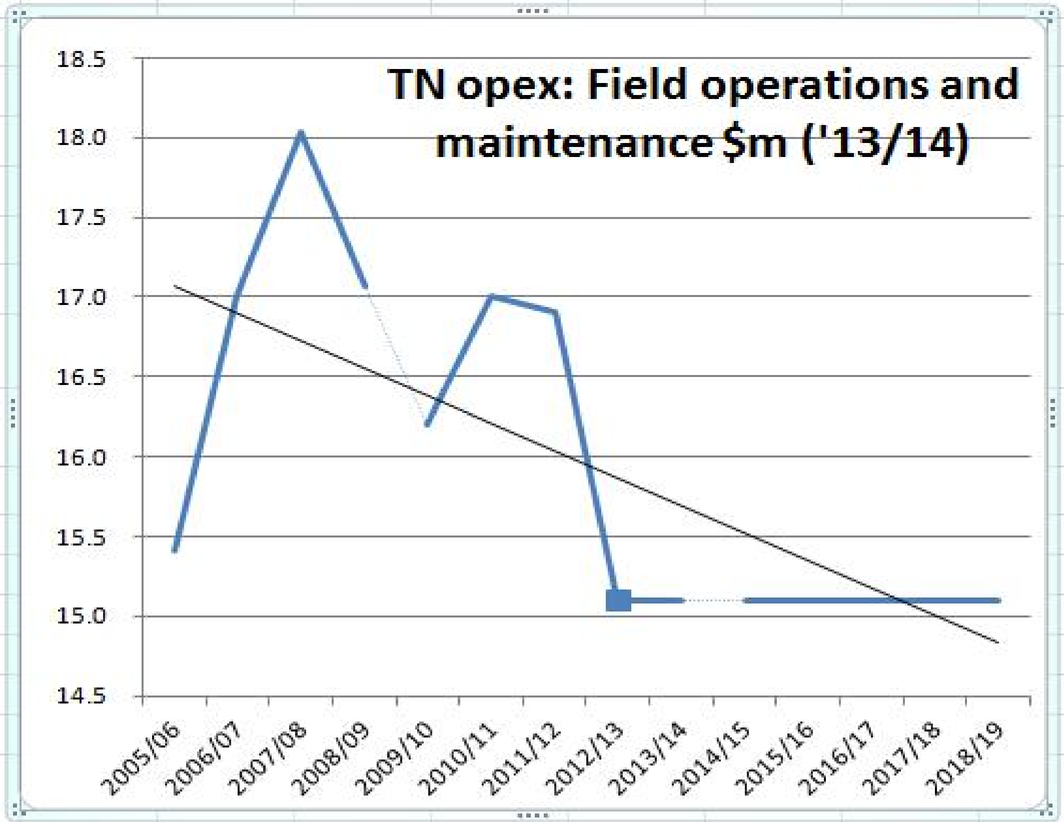
Overall, whilst the MEU applauds TN for reducing its opex to the extent that it has, the MEU is concerned that the current levels of opex are not at the efficient frontier and that the forecast opex still has significant inefficiencies within it, including its reliance on 2012/13 as a base ''efficient' year.

5.1 Detailed assessment of controllable opex

The following sections only examine the major cost centres in the proposed TN opex for AA3.The base year is specifically identified.

5.1.1 Field operations and maintenance opex

TN shows that over the current period (AA2) it has instituted a significant reduction in the field operations and maintenance - a sector of costs that is the single largest contributor to TN opex. The following chart shows the trend in field operation and maintenance opex.

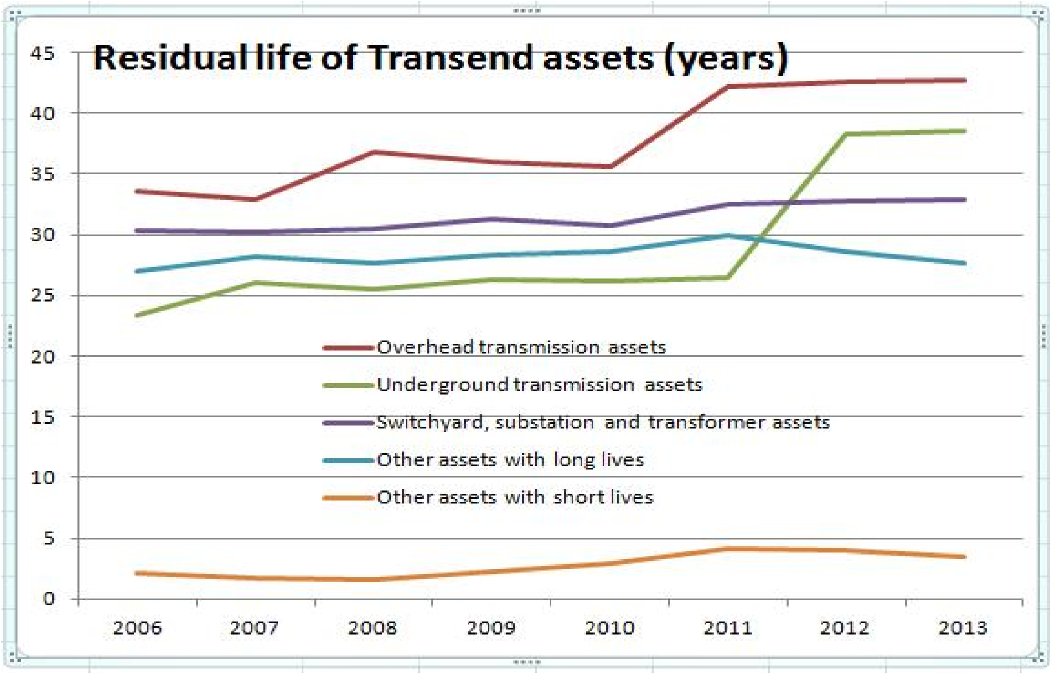


Source: TN applications, TN benchmarking RIN

The chart shows that the base year opex for this sector will not be improved upon for either the final year of period AA2 nor for the forecast period AA3. The trend line implies that there are further improvements to be had based on the amount of work that TN has put into this sector over the past 5-6 years.

Whilst the revealed cost approach would imply that TN is at the efficient frontier and therefore no further savings are likely, the fact that TN is still not the lowest performer in this area supporting a view that there is still more efficiency to be achieved.

The analysis of the residual age of the TN assets shows that its assets are quite young compared to the assets in other TNSP fleets with which it is benchmarked. The residual age of the TN assets is shown in the following chart. When reviewing this chart it is important to recognise that overhead line assets have an expected life of 60 years, underground line assets a life of 55 year and substations an expected life of 40 years.



Source: TN benchmarking RIN

On average, the age of the bulk of the assets is in the "teenage" years. As asset age is a significant driver of field operations and maintenance it therefore follows that as a result of the investment over the past 8 years, there should be a significant reduction in maintenance opex and this reduction should continue into the forecast period.

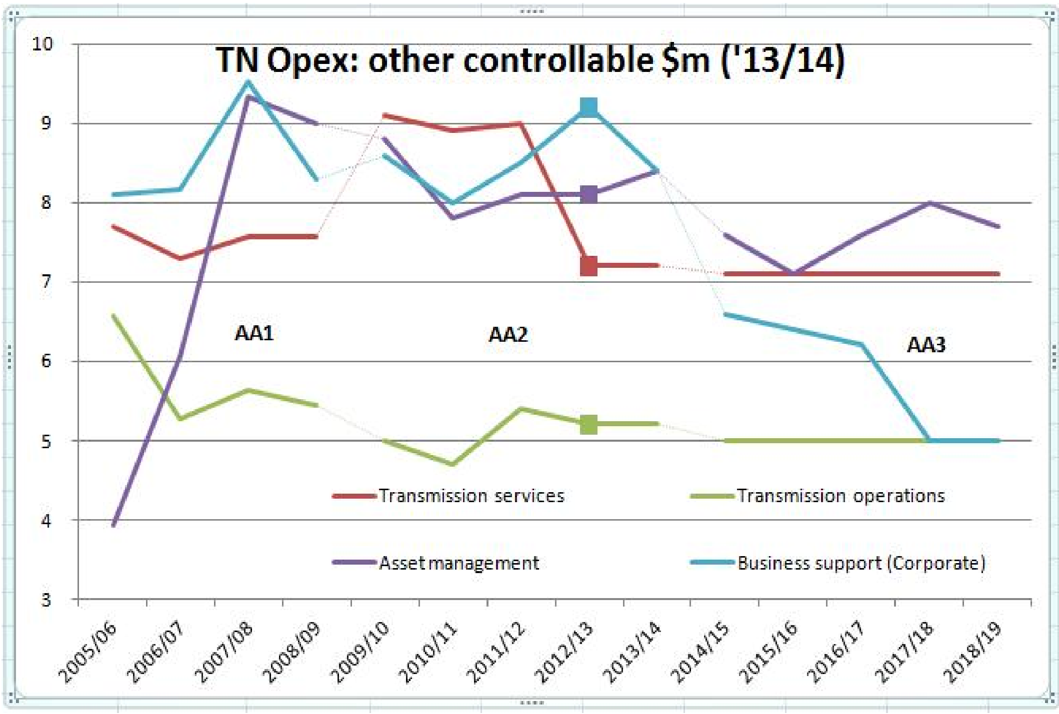
Overall, the MEU considers that there is still more efficiency savings that are possible in this sector of opex and that these should be reflected in the forecasts for AA3.

5.1.2 Other controllable opex

The following chart shows the movement of a number of other elements of the TN controllable opex - transmission services, transmission operations, asset management and business support.

The chart shows that generally each element is relatively unchanged from AA1 to the forecast period AA3.

The element with the largest movement is in business support (overhead) which has, as expected, a significant down ward movement to reflect the planned amalgamation of Transend and Aurora



Source: TN application, TN benchmarking RIN

The MEU notes that the elements of transmission services and transmission operations do not show an efficiency improvement as has been seen for maintenance and the MEU questions why. The MEU would expect that the amalgamation of the transmission and distribution would have led to synergies and should show a similar downward trend as is seen with business support. The MEU also notes that the increase in transmission services seen in the early years of AA2 was quickly overcome in the later years of AA2.

The MEU also is intrigued by the massive spike in the cost of asset management in AA1 and although there has been a drift downwards over AA2 and forecast for AA3, it would appear that the synergies of the amalgamation have not been transferred to this element.

The largest movement is in business support and this does seem to reflect the benefits of amalgamation. However, the MEU considers that the reduction included is insufficient. The MEU notes that the cost of business support for the years of AA1 and AA2 averages $8.5m pa yet the forecast cost for this element averages $5.8m pa - a reduction of only 30%. The MEU would have expected that the benefits of amalgamation would have resulted in a much greater cost saving than this. In this regard, MEU members have observed that they would expect considerably more overhead reduction from synergies from such an amalgamation.

Overall, the MEU considers that while some of the benefits of increasing efficiency and from the amalgamation have been built into the forecasts for AA3, there is still considerable room for greater efficiencies to be provided.

In this regard, the MEU notes that firms in the competitive sector have had to reduce their costs considerably in order to remain in business. TN, being a monopoly, has no such pressures on it and is not being "driven" to ensure that its costs are at the efficient frontier. As is common with monopolies there is a resistance to deliver cost reductions that come from "either reduce costs or go out of business" and as a result there is a degree of "comfort" left in the costs forecast.

This is reflected in the proposed costs that consumers are still seeing. In section 1.3 above, the MEU points out that the costs to users in AA3 are, on average, similar to the average costs they faced in AA2. So at a macro level, the efforts of TN in reducing its costs have not resulted in the benefits that TN discusses in its proposal.

When considering the detail of the opex movements over time and the benchmarking work carried out, the MEU considers there is still room for improvement and the opex allowances for AA3 could be further reduced.

5.2 Uncontrollable opex

In addition to controllable opex, TN has also claimed additional opex in the following elements - network support, insurance (premium and self) and debt raising costs.

TN currently has no network support contracts in place and has forecast that none will be needed in AA3. However, the MEU notes that network support contracts are a pass through cost and if needed, opex will be increased regardless to accommodate any new requirements. At the same time, any capex that is included for network augmentation that might be obviated by network support will be retained. So having no allowance for network support is not necessarily a reflection of what might eventuate.

The MEU also notes that, while the opex for insurance premiums has remained essentially static for the past 7-8 years and the forecasts for AA3 continue this trend, the costs for self insurance have risen dramatically from $100,000 pa to a current level of $900,000 pa. The forecast for AA3 is that this cost will fall to $700,000 pa. The MEU recognises that self insurance costs are assessed actuarially but essentially, they are controllable in as much as the TNSP can decide as to what premium it shall charge itself.

The MEU questions whether the step changes from when the self insurance premium was $100,000 pa have warranted the very large increases seen, particularly whether the seven fold increase forecast for AA3 is warranted.

5.2.1 Debt raising costs

In its historic costs for AA2, TN states that it incurred no costs for the raising of debt; this is true because TN is provided with its debt requirements from its owner the Tasmanian government via TasCorp and therefore it incurs no costs for this activity.

Yet for AA3, it considers that it is entitled to an average of $1m pa to raise debt. To support its view, it goes to considerable effort to prove that this is a legitimate cost and employed PricewaterhouseCoopers - PwC - (presumably an expense that consumers carry as part of the allowed regulatory costs) to argue that TN should be allowed a cost that they do not incur.

TN argues that the approach historically used by the AER does not cover all the costs an NSP incurs in the acquisition of debt and should be increased, yet this assertion is not supported by TN actual costs (which are zero) but developed on a theoretical basis. The MEU considers that the AER should require hard evidence that its approach to assessing the cost of debt acquisition really does result in less than the amount required.

The argument provided by TN and its consultant for an increased allowance revolves around the "indirect costs" of debt acquisition (rather than the direct costs) and relate to the provision of liquidity reserves required by rating agencies and their requirements for management of refinancing costs.

TN incurs none of these indirect costs and it is arguable whether a privately owned NSP would incur these either, especially recognising that the risk profile of electricity networks results in lower costs of debt when compared to other firms with the same credit rating as identified by AER consultant Chairmont during the AER Better Regulation program.

Having argued for an increase in debt raising costs, TN then states that, in the interests of keeping its costs as low as possible, it will not seek the premium that PwC considers it is entitled to.

The TN decision not to seek the indirect costs is to its credit but the MEU considers that being paid for the direct costs for debt raising that it also does not incur should not be accepted as such is not efficient - why should consumers reimburse an NSP for a cost they do not incur?

5.3 Conclusions

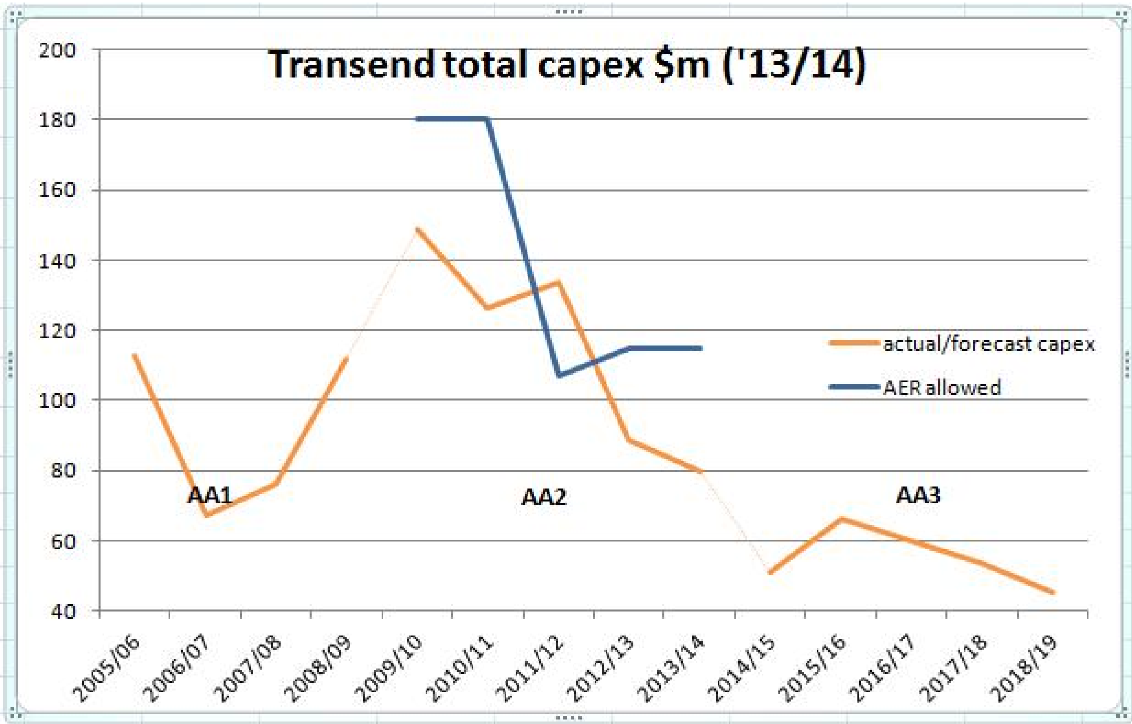
The MEU considers that TN has approached the issue of opex with the aim of reducing their costs, and this is to the credit of TN. Equally the MEU considers that TN is not at the efficient frontier and therefore more cost savings are available but which have not been proposed.

5.4 AER questions

#	AER question	MEU response
1	Are the opex proposals of each business justified? Please identify any specific areas you consider are not justified.	The ME appreciates the effort TN has put into reducing its opex but considers that the levels proposed are not at the efficient frontier and could be reduced further. See comments above
2	What are your views about the cost drivers the businesses have identified?	TN has allowed for costs against each of the elements comprising opex but has not delivered the full value of the reductions that it could and therefore has overstated the amount required for each.
3	Are the benefits to electricity network consumers resulting from revealed efficiencies in opex sufficient to warrant the rewards proposed by the businesses under the EBSS?	The MEU considers that TN played "the game" at the last reset and was awarded considerable increases in opex that were not warranted. As a reuslt, under the EBSS, TN is entitled to a considerable carry forward of a abenefit that it did not earn.Even so, the EBSS approach does drive the opex to be more efficient. This means that the base year should reflect amounts that provide the basis for the next regulatory period, but this supposes that the base year opex is at the efficient frontier. That TN has forecast further opex savings indicates that the base year was not efficient. Of particular note, TN has claimed significant debt raising costs even though it incurs no such costs. The MEU has provided its views in detail in the comments above
4	Are the reasons for the opex proposals of each business clear from their regulatory proposals and/or consumer engagement activities?	See comments above The MEU considers the timing of the consumer engagement would have had a marginal impact (if any) on the reasons for the opex changes due to the timing of the consumer engagement and the development of the application.

6. Capex

TN capex for the Tasmanian transmission system is presented in the following chart showing the actual capex in comparison to the forecast for the next period (AA3). The actual capex for each period is also shown as is the AER allowance for capex.



Source: TN proposal and TN proposal appendix 22,

This highlights that the proposed capex for period AA3 seems quite modest when seen in context with the capex incurred in period AA2, and even AA!. It is important to note that capex for AA3 does not need the augmentation capex that was seen in AA1 and AA2.

The MEU recognises that, in AA1, TN used 25% more capex that had been allowed (although most of the over spend occurred in the last two years of AA1). This over spend provided evidence to the AER that more capex was needed in AA2 as well as augmentation capex needed for the TN networks to manage more than a forecast 15% increase in demand that was forecast to occur over the ensuing 5 years.

The chart also highlights that TN did not use the capex allowed in AA2 by ~$120m (nearly 20%) and by doing so accrued a cash benefit exceeding $25m.[15]

[15] This figure has been assessed based on the aggregate capital under-run each year of the period and the regulated WACC

Detailed reasons for the capex under run have not been provided but TN has reported that much of the under-run was due to the falling demand and the resulting less need for network augmentation. It appears that the significant step increase in capex for AA2 compared to the capex used in AA1 was not warranted.

TN advises that its capex for AA3 will be lower than in AA2. AA2 average annual capex was ~$115m pa (which was a 25% increase from AA1) whereas average capex for AA3 is about $55m or 50% less than used in AA2. The bulk of the reduction is due to a very much lower augmentation capex budget for AA3. At the same time, TN provided more replacement capex in AA2 than it forecast in 2009 as being required.

Whilst TN is forecasting a lower capex budget for AA3 than it actually incurred in AA2 (or even in AA1), it must be highlighted that TN significantly under-ran its budget allowance in AA2. In AA3 TN will be exposed to a capex incentive scheme which will provide a further benefit to TN for under-running its allowance. This means that TN is incentivised to overstate its capex needs for AA3 so that it can "earn" a capex incentive bonus.

The benefit of the EBSS for the future opex allowance is that the revealed costs of opex can be used as the basis for the future opex allowance. The MEU accepts that a capex budget for augmentation might be a little more difficult to apply using a revealed cost outcome although, as the MEU notes in section 6.3 on replacement capex, the revealed cost approach has much more applicability for replacement capex and this is the basis on which the MEU has assessed the proposed TN replacement capex budget.

The MEU is particularly concerned that the claims for capex by an NSP can be influenced by the introduction of the capex efficiency sharing scheme (CESS). Any incentive regime drives an NSP to seek a greater allowance than it really needs. If the AER allows for AA3 (as it did for AA2) significantly more capex than is required, the CESS will deliver considerably more benefits to TN than it achieved in AA2. The introduction of the CESS requires the AER to be much more rigorous in setting the allowances for capex than in previous reviews. Under the EBSS, opex is set at the level seen as efficient from the previous period. In contrast, TN has used zero base approaches to setting the capex for AA3. The MEU considers that the implementation of the CESS requires the similar use of historical performance to set the future allowances for capex rather than allowing bottom up assessments to be used as the basis. The use of a CESS requires greater use of "top down" controls.

The MEU notes that TN is also incentivsed to increase capex as there is a difference between the WACC that the AER will allow under the rate of return guidelines and what TN actually incurs. The bulk of this difference lies with the cost of debt where TN is likely to receive a cost of debt allowance below the cost it actually incurs. This provides an incentive for TN to use more capex than it actually requires to deliver the service.

With capex incentive scheme and the WACC incentive, the MEU considers that the AER needs to assess the capex claims in considerable detail with a view to minimizing the amount of capex allowed.

6.1 Consumer engagement

TN has provided views provided to it by consumers on the capex proposal and various specific elements of it. These consultations were from a number of relatively time limited consultation processes. While the MEU considers that these approaches to consumers are better than the consultation TN had for previous reviews, there has to be considerable doubt as to whether the conclusions TN has reached from this contact really provides strong support for the proposed actions from consumers.

The MEU is very concerned that the time provided for such consultations is well short of what consumers need to fully understand the intricacies of the concepts propounded by TN and the consumers' abilities to make informed decisions on such complex issues.

Further, the MEU notes that the timings of the consultations are such that the MEU considers that TN would have already had to make decisions on build up of its application and that the consumer consultations were more to obtain support for decisions made rather than to influence the decisions.

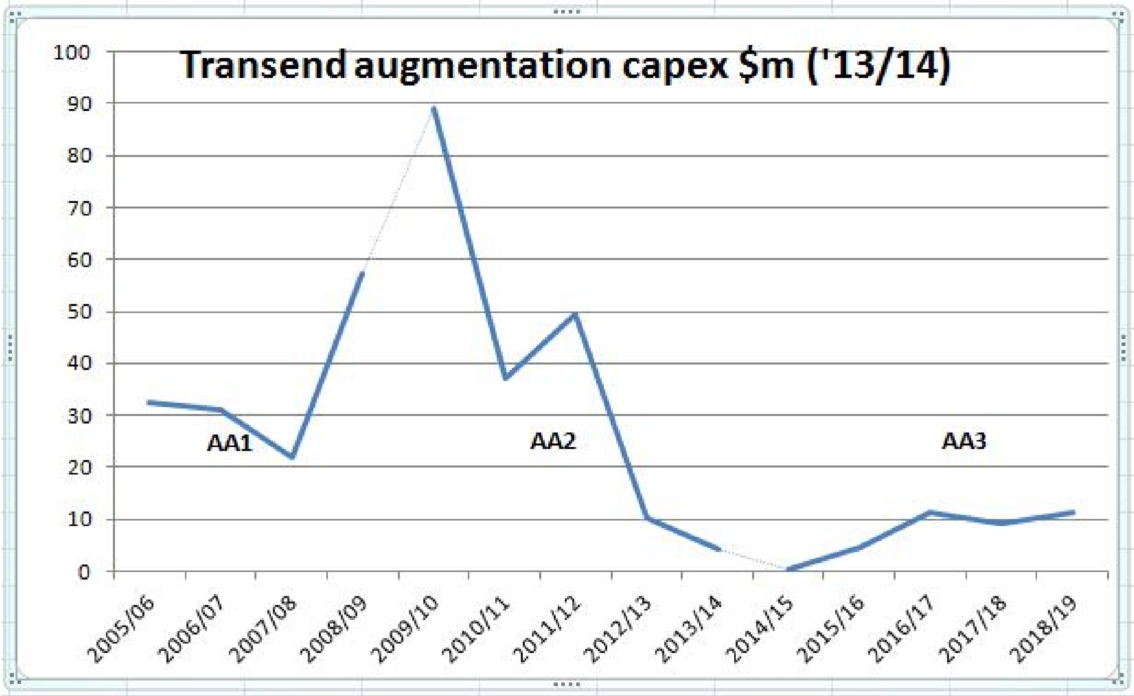
One of the key decisions that has been made from the consumer engagement is that consumers do not want to see a reduction in reliability, even if this is provided at a lower cost. On this basis TN has determined a capex program such that its current approach to reliability will not be impacted.

What concerns the MEU is that consumer engagement processes are so time and resource limited that making an informed decision on the cost/reliability trade off is unlikely. The MEU notes that the information provided by TN implies that any reduction in cost will have a reliability impact. In fact, the MEU is well aware that there could be a considerable reduction in capex before any discernable reduction in reliability occurs. Further, in the event of a reduction in reliability, it is not made clear what the outcome for consumers would actually be.

With this in mind, the MEU cannot accept the assertion by TN that they are constrained in their assessment of capex needs by the observation from consumers that a lesser level of reliability will result.

6.2 Augmentation capex

Analysis of the TN augmentation capex in AA1, AA2 and its forecast for AA3 is revealing. Augmentation capex is shown in the following chart.



Source: TN application appendix 22

Examining the proposed augmentation capex for AA3 compared to that of AA1 and AA2 shows that, after spending considerably on augmentation in AA1 and during AA2 due to the expectation of continued growth in demand, TN has identified that demand in Tasmania (medium growth expectation) is forecast to remain below the peak experienced in 2008 over the next period (AA3). In contrast, under all of the AEMO scenarios, AEMO does not expect peak demand to exceed the 2008 peak at any time in the 10 year forecast[16]. TN goes to some length to explain why it considers its forecast is preferred to the AEMO forecast. Despite this difference, TN accepts that there is little requirement for augmentation during AA3 to accommodate growth in demand.

However, TN includes two projects (Wandana-Palmerston 220 kV security augmentation and Newtown-Queenstown security augmentation) in its forecast capex for later in the period AA3. TN states that both of these projects will have to undergo a RIT-T evaluation - a process that has not yet commenced. The MEU view is that neither of these projects is now "firm" as being required or showing a net benefit.

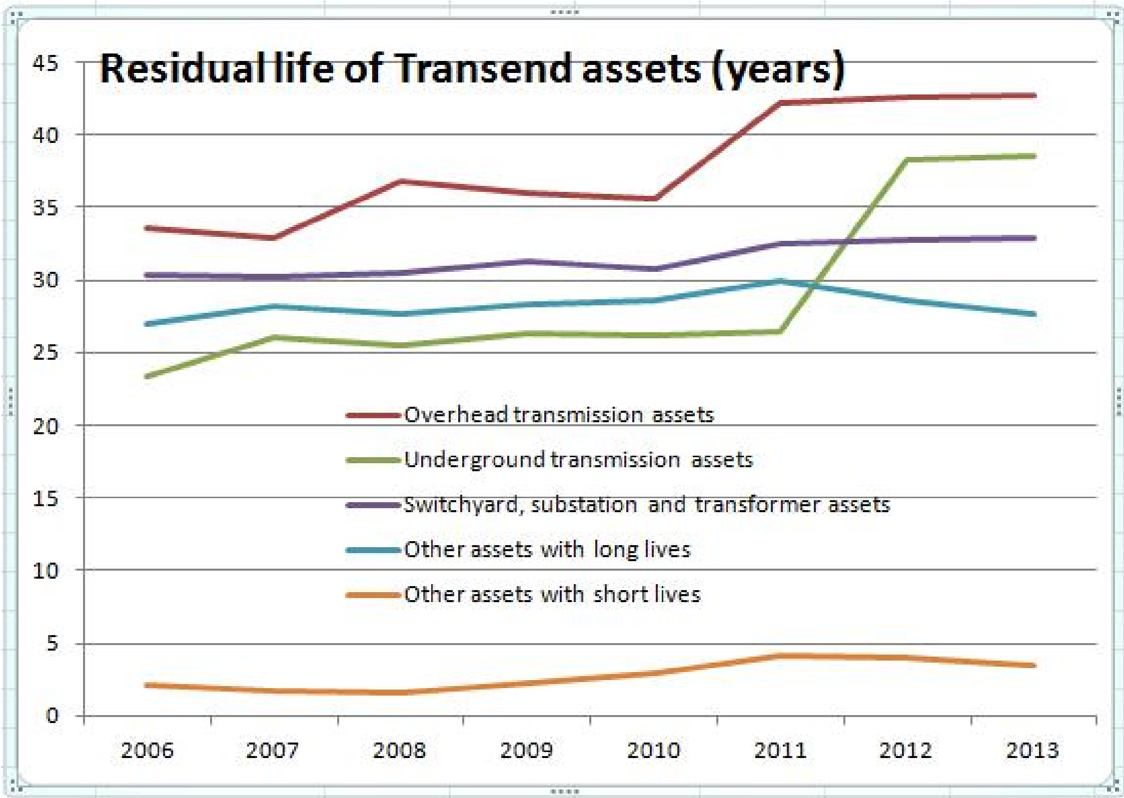
Noting that there is some difference of view between TN and AEMO forecasts and that neither project has been proven to be necessary or delivering a net benefit, the MEU considers that both projects should be included as contingent projects and not be included in the capex budget for AA3.

[16] See section 2.1 for more on this issue

The MEU notes that TN has forecast there will be no new connections required to the network but forecasts upgrading of existing connections for the distribution network to address fault levels, reliability concerns and increasing transformer capacity. The MEU is not in a position to question the legitimacy of these projects but does query why they are needed if there is no new increase in demand and that reliability is at an acceptable level. The fact that there was significant investment in connection assets during AA2 when there was effectively a falling demand subsequent to the 2008 peak demand implies that the AA2 period investment in connection assets has "preloaded" the network with greater capacity than is needed for forecast period AA3.

6.3 Renewal/enhancement (replacement) capex

The MEU has reviewed the residual life of the assets already in place in the TN network. The TN benchmarking RIN data table 4.4.2 can be shown graphically as follows.



Source: TN benchmarking RIN table 4.4.2

The importance of identifying the residual lives of the TN assets is to highlight the impact of previous capex on the average age of the network. Generally, replacement capex (when coupled to augmentation capex) should result in an average age of about 50% of its expected life being maintained through the regulatory period. When the average age is lower (ie has a residual life more than 50% of the expected life) then less replacement capex is required. In converse, where the average age exceeds the notional 50% of expected life, there is an expectation that more replacement capex might be required although the same outcome might occur if there is significant augmentation capex included in the network.

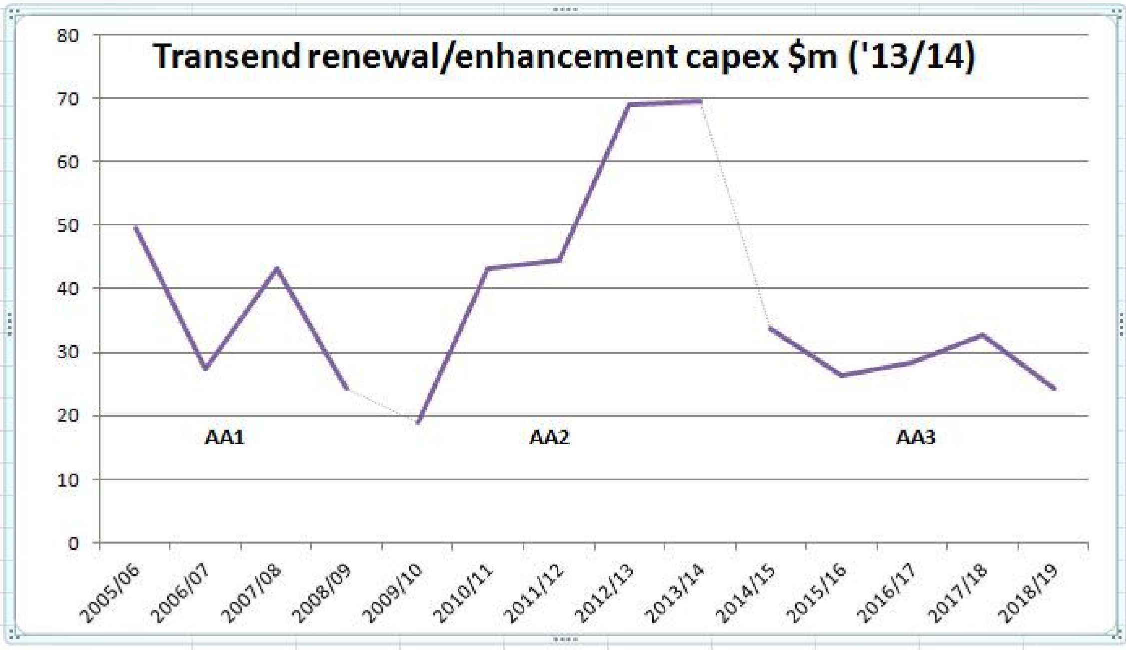
The assessment of the residual life of the TN network elements clearly shows that the residual lives significantly exceed 50% of the expected lives. For example, overhead transmission lines have an expected life of about 60 years (see TN benchmarking RIN table 4.4.1). By 2013, the residual life of this asset class is about 42 years or an age of about 30% of expected life. Without any investment in the next period (AA3), the average age of this asset class would be nearly 40% of expected life, still well below the 50% target.

Following the same approach, switchyard assets would have an average age of only 30% of expected life by the end of AA3.

This simple analysis implies that there is little need for any replacement capex in the next period (AA3) and that the expenditure to date has effectively "preloaded" the network with new assets to reduce the average age of the network considerably.

In previous years, replacement capex has been the second largest capex element of the TN expenditure, usually well behind augmentation capex, although during AA2 (and at times in AA1), replacement capex exceeded augmentation capex in the later years. In this application, TN has elevated replacement capex to the largest cost element in its capital cost budget.

The following chart shows the long term trend in replacement capex and this shows that replacement capex rose ~$36m pa in AA1 to about $50m pa ($'13/14) in AA2; at the same time augmentation capex was high too. TN is forecasting a reduction in replacement capex in AA3 to about $30m pa, slightly less than that incurred in AA1.



Source: TN application, Appendix 22

The MEU has insufficient detail on which to provide a detailed analysis of each projects proposed but recognizes that such projects are developed on a "bottom up" approach based on assessment of need. As a general observation, the MEU considers that renewal/replacement projects can be assessed on a revealed cost approach rather than on a bottom up basis. This is because replacement of assets is a continuing process whereas projects that are load driven (ie augmentation projects) are essentially driven by specific needs at any one time. The MEU therefore considers that the capex allowance for projected renewal projects can be guided by historic performance, especially as now capex is subject to an incentive scheme.

On this basis it would seem that the replacement capex forecast for AA3 would be consistent with past replacement capex proposals. But such an approach does not reflect the reality that the network is now considerably younger than is efficient, as the MEU noted in the early part of this section.

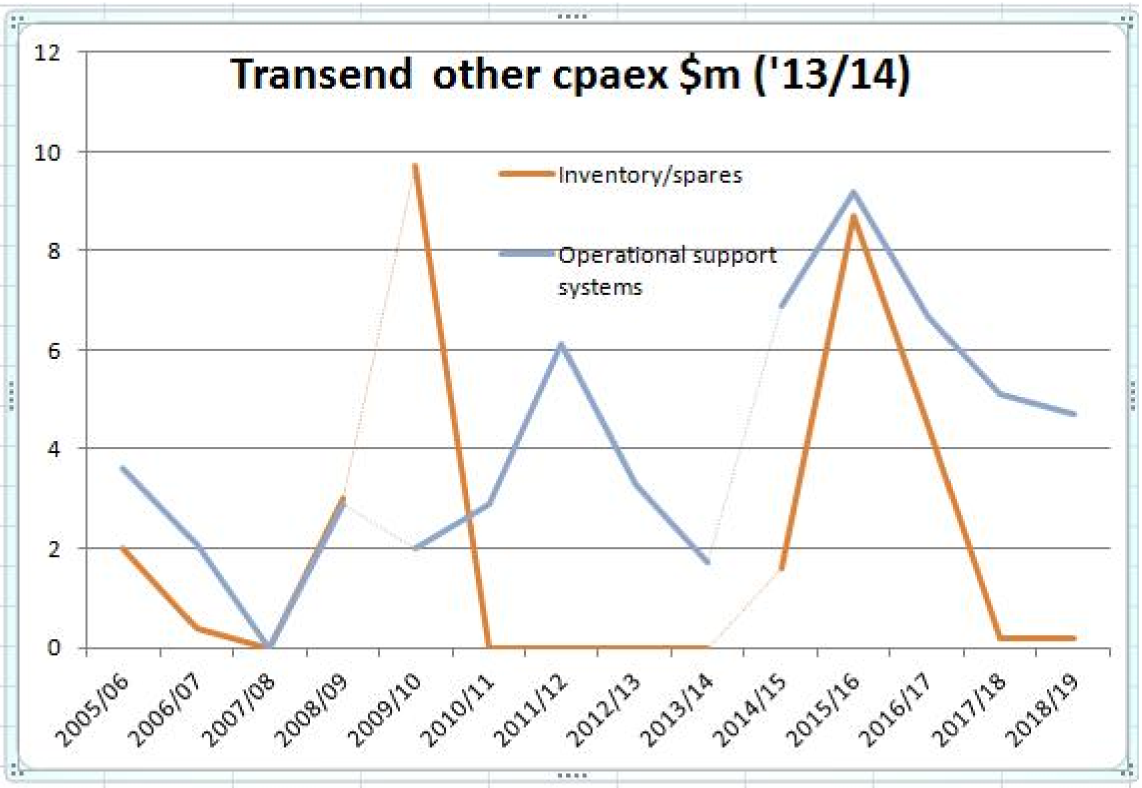
The reason for the network being younger than the average age of 50% of expected age is that TN has significantly invested in both augmentation capex and replacement capex in periods AA1 and AA2 compared to the real needs of the network.

As the network is considerably younger than 50% of average age, there is little reason for the investment of replacement capex at a similar rate as occurred in AA1, particularly as there was an apparent overspend in AA2. It would appear that the investment in AA1 and AA2 has "preloaded" the need for replacement capex and TN should spend much less on replacements in AA3 than it is forecasting.

6.4 Other capex

The MEU has reviewed the other capex elements at a high level and consider that generally, subject to deeper AER analysis, the capex claims are reasonably consistent with past capex in those categories. However, some do show an upward trend above the long term allowances such as in the case of inventory/spares and operational support systems. These deserve a closer look by the AER.

The following chart shows the long term trends in these costs.



Source: TN application appendix 22

TN does not especially comment on inventory/spares or on operational support systems. The MEU considers that both categories can be benchmarked against historical performance.

In the case of inventory/spares, the AA1 usage was low and shows a major spike in AA2. The MEU queries why another spike in AA3 (which results in this category being 60% above the AA2 usage) is required in AA3.

The average cost of operational support shows an increasing annual average trend over the periods of AA1 and AA2 where, in AA2, the capex increased from AA1 levels by some 50% to $3.2m pa. What is concerning is that capex for this element is forecast to increase by another 100% in AA3 to an annual average of $6.5m pa. However there is no explanation as to why this is necessary.

6.5 The relationship between capex and opex

There is a relationship between capex and opex. With the increase in capex for refurbishment and replacement, there must be a proportionate reduction in opex, as this is what justifies the replacement of old assets with new assets. Notwithstanding this inverse relationship, TN does not seem to reduce its opex to reflect the very large increase in residual age of the network.

Where there is growth in a network there is an expectation that there would be additional opex attributable for new capex for the extension of the network, but where capex is about replacing old assets with new, or replacing old with something new but larger, there is no justification for added opex and, indeed, an argument for less opex due to the newness of the replaced equipment.

The AER must recognise the inter-relation between capex and opex as far as the TN application is concerned and ensure that the opex reflects the introduction of new assets for old, that has occurred through AA2.

In this regard the MEU points out that there is an economic driver for TNSPs to replace assets rather than continue with incurring opex. It is the building block approach which provides this driver, as opex is recovered at cost whereas assets achieve a return which provides the profits for the regulated business.

The AER must ensure that the capex used does result in opex being proportionately reduced.

6.6 Conclusions

The MEU considers that, even though capex for AA3 is forecast to be significantly less than that in AA2 (and even that in AA1), TN has still made an ambit claim for capex and that detailed evaluation indicates that the capex claimed is still overstated in most areas.

In particular, the MEU considers that TN has significantly overstated its needs for replacement capex, but has also claimed more than necessary in other elements of the capex build up

6.7 AER questions

#	AER question	MEU response
1	Are the reasons for the capex proposals of each business well supported by their revenue	No. See comments above. Whilst the need for some of the capex is explained, TN does not provide details for significant amounts of

	proposals and/or consumer engagement activities?	capex. Even where it provides some support for the planned capex, the details do not support the extent of the capex claimed. Further, while TN does provide an explanation as to what the capex is to do, it does not provide an explanation as to why the capex is efficient.
2	What are your views about the cost drivers the businesses we have identified?	See comments above
3	Do you consider the transmission businesses have accurately reflected customer preferences for reliability outcomes and their proposed capex to maintain existing levels of performance?	No. The MEU considers that the timing and duration of the consultation could not have provided the in depth analysis that consumers would have to have applied in order to make constructive comment.

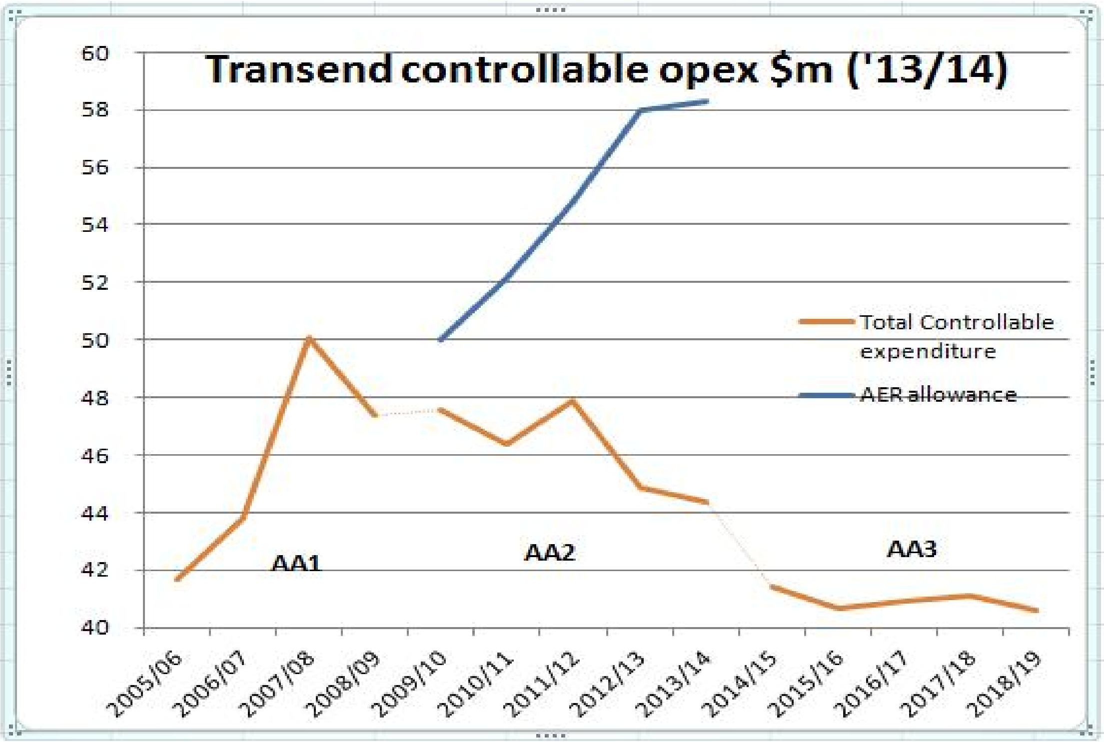
7. Efficiency gain

The MEU is totally supportive of an opex incentive scheme to encourage regulated businesses to reduce their costs. The benefit of this is that TN can reduce the costs of providing the service, and by sharing the savings with TN, consumers will be better off in the long term.

There are two caveats to this in-principle support;

1. The savings should be the outcome of actions by TN and not just because TN was able to convince the regulator at the last reset to give a greater allowance than was necessary, and
2. The savings achieved will continue to be shared well beyond the next reset.

TN advises that there was an under run in actual opex compared to opex allowances granted for the current period and this generates a payment to under the Efficiency Benefit Sharing Scheme (EBSS). The under-run in opex was seen in many years for the last two periods (AA1 and AA2). The following chart is the same as that developed for section 5 above.



Source: TN applications, AER decisions

TN identifies that they did not over-run the allowable opex in period AA2 but did did so in the last two years of AA1. After peaking in opex in the second last year of AA1, TN convinced the AER that considerably more opex was needed for period AA2. Despite a significant increase in opex allowance for AA2, TN has consistently reduced its opex needs consistently ever since. The consistent and excessive under-running of opex in AA2 provides a view that the opex savings being made are not so much an outturn of continuous improvement (which is the intention of the EBSS) but an indication that TN has been able to convince the regulator of the need for higher allowances for opex, allowing TN to earn both the immediate benefit of opex under run and an additional benefit into the next period

The fact that the actual opex never approached the allowed level in AA2 gives rise to a very real concern that the bulk of the opex under run since 2009 has been the result of regulator "gaming" of initial forecasts rather than TN causing real savings from their own actions. At the very least, it indicates a gap in resource planning such that planned opex could not be delivered within the specified time periods.

The MEU does not support providing TN a benefit which is unjustifiable and contributes to an incentive to overstate opex claims.

With this real concern in mind, (as demonstrated empirically above) it is suggested that the AER seeks detailed advice from TN substantiating that savings really have been achieved **by direct operational actions** of TN. TN must be required to provide details of specific actions they have taken, and the resultant cost savings that resulted from each particular action before any sharing of this opex underrun is permitted.

As this underrun is so consistent, the MEU is sceptical as to its validity as an "earned" underrun as distinct to a "gamed" under run. With this in mind, the MEU considers there is no justification for any carry over into the next period.

8. Service standards

TN considers that its service standards performance has been good and will use the new (version 4) STPIS as the basis for its future performance incentive arrangements.

TN advises that the targets are based on the average of the past five years. The MEU has not checked that the targets actually reflect the historic performance, particularly as the STPIS provides a number of exclusions to be included in the calculations.

The MEU notes that TN has set the caps and collars based on 1.5SD of the target. The MEU considers that 1.5SD is an appropriate range to set the caps and collars.

Table 13.2 Proposed STPIS values

Parameter/sub-parameter	Weighting (% MAR)	Collar	Target	Cap
Average circuit outage rate	**±0.50**			
Lines outage rate – fault	±0.20	53	31	10
Transformers outage rate – fault	±0.20	17	12	6
Reactive plant outage rate – fault	±0.10	15	3	0
Lines outage rate – forced outage	0.00	18	10	2
Transformers outage rate – forced outage	0.00	5	3	1
Reactive plant outage rate – forced outage	0.00	33	14	0
Loss of supply event frequency	**±0.30**			
> 0.1 system minute	±0.15	12	10	8
> 1.0 system minute	±0.15	6	3	0
Average outage duration	**±0.20**	**165**	**112**	**58**
Proper operation of equipment	**0.00**			
Failure of protection system	0.00	15	9	4
Material failure of supervisory control and data acquisition (SCADA) system	0.00	68	37	6
Incorrect operational isolation of primary or secondary equipment	0.00	6	4	2

However, the STPIS performance reflects that the outturn service performance is heavily influenced by the amount of opex and capex involved. In this application, TN has already invested considerably in replacement capex in the current period (AA2) and proposes to maintain its replacement capex in the next period (AA3). These increased expenditures should lead to better service performance and thereby generate a bonus under the scheme. Whilst the AER Better Regulation program recognises that there is a degree of harmonization between the three incentive schemes (STPIS, EBSS and CESS) all are dependent on the use of the revealed cost approach to set efficient allowances. As TN has had increased allowances for opex and replacement capex above the historical levels in AA2, the MEU is concerned that the service standards derived for AA3 might not be consistent with the other schemes.

In particular, the historic service performance was based on a period where replacement capex was very high in the last two years of the current period AA2 yet the targets are based on performance before this replacement capex was brought into service compared to the amount of capex sought for the period over which the STPIS will be applied. This amount of increased replacement capex must result in improved service performance.

In addition to the replacement capex, TN will also achieve better service performance from the NCIPAP process, further indicating that the service targets will be more than achieved.

The MEU considers that there must be a balancing of the impact of the increased replacement capex and the NCIPAP on the service performance targets. It would be a bizarre outcome for consumers to pay for increased capex and opex so that TN could "earn" a STPIS bonus. Certainly an outcome such as this would not be efficient or in the long term interests of consumers.

9. NCIPAP

TN has provided a table A1.2 in appendix 21 of its proposal showing that its proposed Network Capability Incentive Parameter Action Plan (NCIPAP) will increase its revenue over the forecast five year period by an average of 1.7%.

Table A1.2 Total Network Capability Incentive Parameter Action Plan expenditure ($'000 2013–14)

	Expenditure					
	2014–15	2015–16	2016–17	2017–18	2018–19	Total ($'000)
Total Expenditure	**3,614**	**3,226**	**3,271**	**3,535**	**1,741**	**15,387**
Capex	3,389	2,994	3,024	3,274	1,474	14,155
Opex	225	232	247	261	267	1,232

The above total expenditure equates to approximately 1.7 per cent of Transend's proposed revenue.

As the MEU understands the NCIPAP, an allowance of 1.5% of revenue (rather than the 1.7% proposed by TN) is permitted to be included as the NCIPAP. The proposed NCIPAP includes 21 small projects that could be undertaken and which are to deliver a clear definable benefit for consumers. For completing these projects, the network receives a reward of up to 2% of allowed revenue. As the process currently stands, there is no definable benefit that must be achieved nor must the expected benefit be measured on completion to ensure that the benefit has actually been achieved.

What the MEU finds difficult to accept, is that many of these projects should have been addressed by the networks under their normal capex and opex programs and it raises the simple question as to why they have not addressed these obvious needs in the past and have only now looked at them because there will be a reward.

For such small discretionary projects, the most common approach used by firms in the competitive sector is to assess projects such as these is on a simple pay back method – that the benefits of a project had to be recovered by savings made in 1-2 years (or perhaps 3 years at the most). The NCIPAP operation does not guarantee to deliver this sort of benefit (in fact there is no definition of the benefit that must be achieved). Further, in a competitive environment, if the project does not proceed there is no cost incurred. Under the NCIPAP, if the project does not proceed, there is a payment although this might be offset against the penalty, but again there is no certainty that the value of the penalty will exceed the value of not carrying out the project providing the network with a reward for doing nothing.

While the MEU supports encouraging networks to identify and complete projects that add value to consumers, the major flaw in the NCIPAP is that there is no certainty that real benefits will be delivered although there can be certainty that projects (whatever the benefit they deliver) can be delivered. This means that consumers will be paying for projects that have no certainty of delivering any benefit, let alone a commercial benefit.

The NCIPAP process is totally dependent on the network gaining agreement from AEMO that the projects identified will deliver a benefit to consumers. Transend has nominated 21 projects for the NCIPAP yet the table A1.1 states that AEMO does not endorse projects 1 and 2 listed in the table. AEMO is stated to have endorsed the other 19 projects listed, presumably being seen as providing value for money; there is no substantive indication of why the two projects not endorsed have "failed" the AEMO test.

Included in some of the projects are costs for both capex and for opex. It is not clear whether the opex cost is a "once off" cost or whether the cost is an annual cost. Equally, it is not clear whether a capex cost is to be added to the RAB or if it is made as a single payment. The MEU has assumed that the costs are "once off" payments and do not get added into the RAB (for capex) or into the annual opex allowance at the next reset. The NCIPAP process needs to be clearer as to how costs are to be recovered.

TN provides some details of its 21 projects and what is provided is focused on what the project is. Of concern is that the development of the benefits is not explained at all and if the benefits will be delivered regardless or if they only provide a benefit under certain circumstances. The MEU cannot accept that the stated benefits are real unless there is some explanation as to their development and if they are affected by some uncertainty of specific conditions being required for the benefits to be realised.

The MEU is concerned that the anticipated benefits claimed for the projects can be overstated and, as there is no requirement to demonstrate at a later time that the benefits calculated were actually achieved, consumers have no certainty that their payment for these additional works has been beneficial. What they do know is that they will have paid for a project and the TNSP will have earned a bonus for carrying out the work.

These observations reinforce the concern of the MEU that the NCIPAP approach, by not requiring confirmation that the expected benefit has been achieved, provides a biased assessment of the benefits of the projects.

On the assumption that the benefits are real and have a firm basis for their return to consumers, the MEU makes the following comments.

- Projects #1 to #12 all have a simple payback of just over 2 years, although the payback for project #3 seems to have a simple payback of between 6 months and 7 years depending on the line involved. These projects would appear to be acceptable for inclusion in the NCIPAP.
- Projects #13 to #21 are not acceptable as they have a simple payback of 4 years or even greater; project #21 has a payback of 41 years and

would probably not even pass the usual capex acceptability under a RIT-T.

On this simple analysis the MEU considers that the AER should not allow projects #13 to #21 to be included in the NCIPAP. The fact that AEMO has endorsed these projects raises the concern that AEMO endorsement means little with regard to the financial benefits of the project evaluation. It would seem that AEMO endorsement merely means that the project might result in an improvement of the network operations regardless of the cost. The AER needs to develop an understanding of what AEMO endorsement really entails.

On closer examination of the projects that appear to deliver an acceptable simple payback to warrant their inclusion in an incentive scheme, the MEU is concerned that a number of the projects are merely to reset the short term ratings of specific equipment and power lines and so allow increased power transfer capability. This seems to imply that TN has previously provided advice to AEMO (as the controller of the power flows) that was overly conservative. This then raises two questions:

- Why this has been done and why consumers should pay a reward to TN for doing what it should and could have done in the past recognising that TN is an expert in relation to its network?
- How has the benefit been calculated? For much of the time power flows are well below equipment ratings. So what is the basis for the calculation of the benefits and are the assumptions reasonable?

The MEU notes that projects #1 and #2 are not endorsed by AEMO although TN comments that project #2 should have been in its note 1 to the table A1.1. On reading the descriptions of the two projects the MEU agrees with AEMO that they are part of normal operations and do not warrant NCIPAP involvement.

In particular, project #1 is merely the continuation of existing operations and should be part of the normal opex, so why is it included as a NCIPAP project? The benefits would appear to be strong, yet the existing costs should be in the current opex allowance. What is more important, if this project has such a high benefit to cost why was it not included previously under the normal regulatory review process.

It would appear that TN is using the NCIPAP process to gain a reward for doing what it should have already implemented.

What is also obvious is that a number of projects should/could have been carried out under the market impact component (MIC) incentive but presumably the rewards under the MIC were assessed as not warranting the investment to achieve these outcomes. This then reinforces the concern of the MEU that the NCIPAP approach, by not requiring confirmation that the expected benefit has been achieved, provides a biased assessment of the benefits of the projects.

There are a number of aspects of the NCIPAP program that are not clear and the AER needs to ensure that consumers are made aware of how those projects that are allowed are to be addressed over time.

At the most fundamental level, the AER has to implement a "hard payback threshold" for the NCIPAP process. To be consistent with approaches used in the competitive sector, the MEU considers that no project with a simple payback longer than 2 years should be allowed in the NCIPAP.

Overall, the MEU is very concerned that the NCIPAP program is being used to generate a much better outcome for TN than was the original intent of the program.

10. Pricing methodology

In a submission made recently to the AEMC on the prosed rule changes to distribution pricing the MEU provided the following longitudinal assessment of transmission pricing

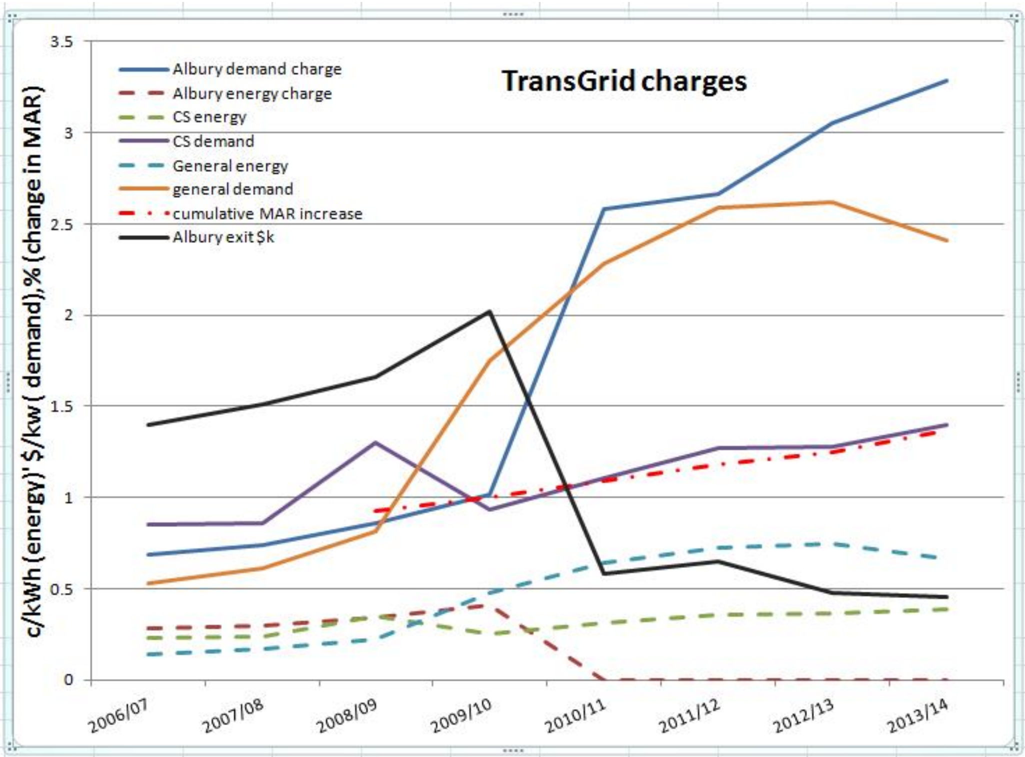
"2.1 Transmission pricing observations and analysis

Two transmission network tariffs were analyzed - TransGrid in NSW and Transend in Tasmania - and analyzing the network costs over time, demonstrates some interesting aspects of the prices developed.

2.1.1 TransGrid pricing

The MEU has tracked the TransGrid network prices over the past eight years. For the purposes of this exercise, the Albury substation prices were recorded and the following chart shows the price movements over time for each element required under the rules.

At a high level, the chart reveals that there have been massive movements in the prices for the individual elements over time. At the same time, consumers' expectations that prices would follow the changes in revenue allowed by the AER was not fulfilled even though this was the basis on which consumers would have forecast their future electricity cost budgets.



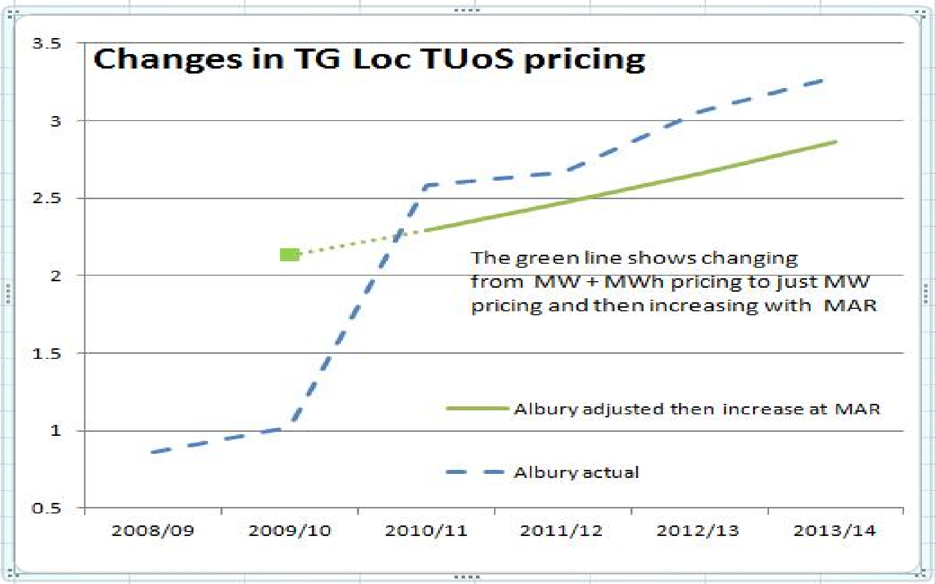
Source: TransGrid price lists

As can be seen for TransGrid prices, there are quite significant movements year on year that do not follow the pattern of the trends implied by the AER decisions on TransGrid allowed revenues. There are three particular features that should be noted:

- Whilst there is an expectation that the year on year changes in prices for Common Services and General (non-locational TUoS) when charged on an energy basis would closely correlate with the changes in prices for these services levied on a demand basis, this is not the case. Analysis of the year on year differences between the prices set on an energy basis and on a demand basis shows that the differences between the two exceeded 5% points. With such a large variation, this means that cost recovery is being biased with high load factor users being charged more than low load factor users. This is contrary to the drive in the Power of Choice report where overall increases in load factor are the focus of many of the actions proposed.

- The exit prices also do not follow the trends expected with a massive downward change in 2010/11 in stark contrast to the upward revenue adjustment made in 2009/10. Subsequent to 2010/11, exit prices trend slightly downward against the general upward movement of the revenue allowance

- In 2009/10 the AER advised TransGrid that it could no longer charge locational TUoS on a mix of demand and energy, and that it had to be charged only on a demand basis from 2010/11 onwards. The pricing outcome for that decision resulted in a higher pricing than would be expected from the elimination of the energy price as the following chart shows.



Source: TransGrid price lists, AER decisions, MEU calculations

This chart shows that the actual the price rate for locational TUoS exceeded the expected price rate by over 15% on average when the change was made.

Discussions with TransGrid also highlight another feature that affects the approach taken. As the coordinating transmission network in NSW, TransGrid not only has to accommodate in its own transmission pricing, but also recover the transmission costs incurred by Ausgrid and Directlink.

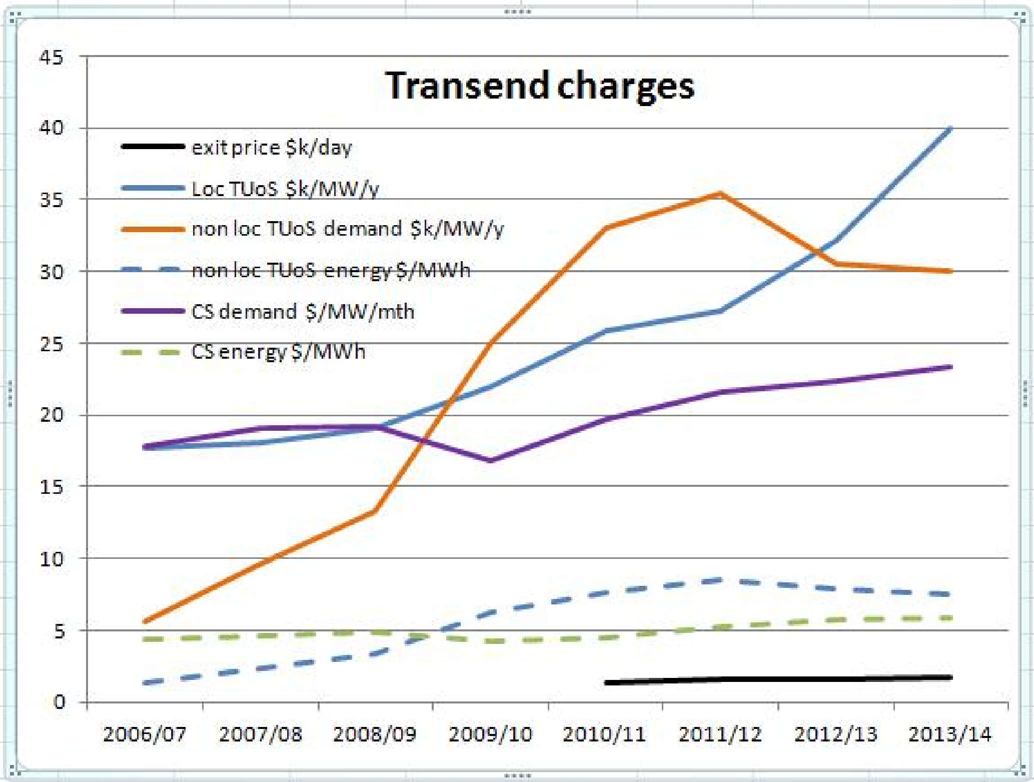
Directlink only provides a service to users on the north coast of NSW and the Ausgrid transmission elements are embedded in the Ausgrid distribution network thereby supporting Ausgrid distribution users. Despite this, TransGrid aggregates the transmission costs of both Ausgrid and Directlink into its overall transmission costs, and then allocates the combined costs to all consumers in NSW. This means that those consumers in the south of the state pay for the Ausgrid and Directlink transmission - assets that they do not use.

To identify further other aspects of the approach used by TransGrid to set its transmission pricing, attached as appendix 1 is the response to the TransGrid pricing review prepared by MEU affiliate Energy Markets Reform Forum (EMRF). This more fully examines the inconsistencies seen by consumers in the TransGrid approach to pricing. Although the report is specific to TransGrid, the MEU considers that a number of the issues identified could well be extrapolated to other transmission networks.

2.1.2 Transend pricing

The MEU has tracked the Transend network prices over the past eight years. For the purposes of this exercise, the New Norfolk substation prices were recorded and the following chart shows the price movements for each element required under the rules.

At a high level, the chart reveals that there has been significant volatility in the prices for each of the individual elements over time. At the same time, consumers' expectations that prices would follow the changes in revenue allowed by the AER was not fulfilled even though this was the basis on which consumers would have forecast their future electricity cost budgets.



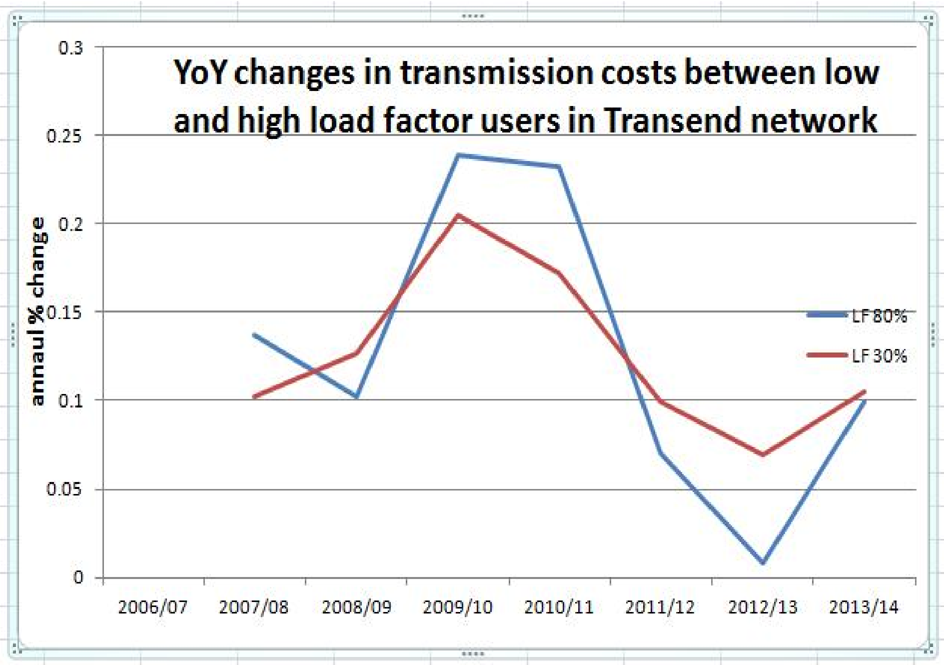
Source: Transend price lists

There are three features of the Transend pricing that should be noted.

- Whilst with the TransGrid pricing there is a loose correlation between locational TUoS and general (non-locational TUoS) with the variances explained by allocation of settlements residues, with Transend there is little correlation at all. As locational TUoS and non-locational TUoS are "two halves making a whole" there is an expectation there will be some correlation, yet this does not occur in the Transend pricing.

- Whilst there is an expectation that the year on year changes in prices for Common Services and General (non-locational TUoS) when priced on an energy basis would closely correlate with the changes in prices for these services levied on a demand basis, this does not occur. Analysis of the year on year differences between the charges made on an energy basis and a demand basis shows that the differences between the two were as high as 10% points. With such a large variation, this means that cost recovery is being biased between high and low load factor users.

  This is shown in the following chart where the year on year changes in transmission costs for a high load factor user (80% load factor) transmission costs are compared with costs for a low load factor user (30% load factor)[17] despite both having the same demand.



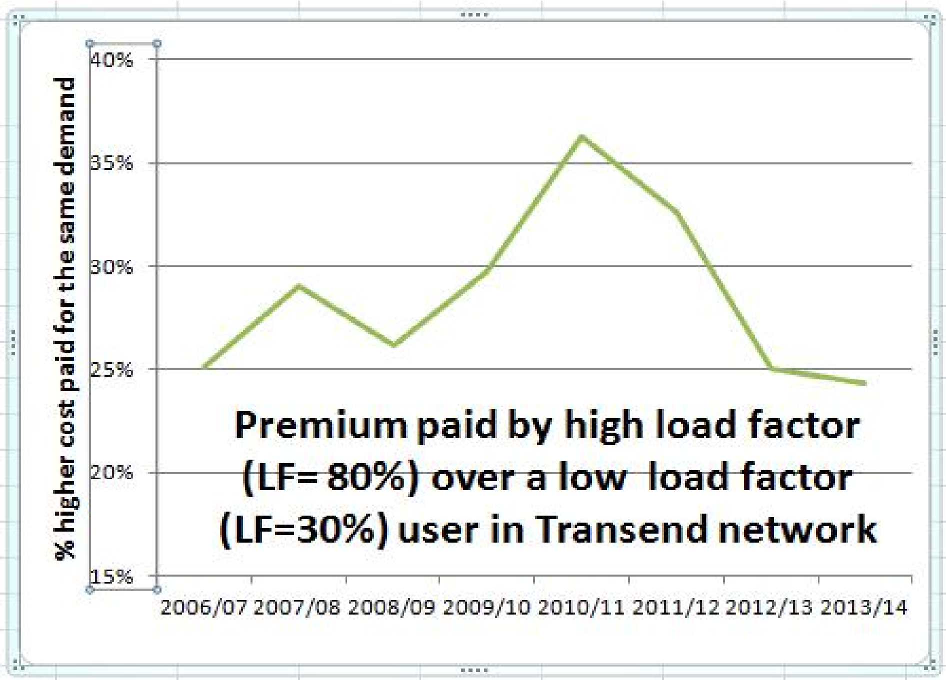
Source: Transend price lists, MEU calculations

  This supports a view that cost reflectivity is not being applied because the swings for high load factor users are more volatile than that for low load factor users as the high load factor user would have a much more predictable load and therefore exhibit more predictability in revenue.

  A similar outcome is seen in the case of TransGrid but is less pronounced

[17] The high load factor is typical of any one of the five largest users in Tasmania and the low load factor is the typical load factor on a state wide basis when the high load factor users are excluded.

- The issue of the load factor goes further. Using the same exit point (New Norfolk) and costing transmission for two users with the same the same demand but different load factors (80% and 30%), the high load factor user pays a considerable premium for transmission services and this premium is shown in the following chart.



Source: Transend price lists, MEU calculations

The chart shows that the pricing clearly discriminates against the high load factor user because of the ability to pay for general (non-locational TUOS) and common service (whichever is the lower), despite both users having the same demand. As transmission assets are sized to meet the peak demand at any exit point, the transmission cost should be much the same for the same sized demand. This clearly does not occur under the Transend approach to pricing.

What is also concerning is that the premium varies considerably year on year with a general premium being some 25% but reaching above 35% at times. This volatility is not expected and should be more stable if pricing reflected the costs incurred in the service provision.

A similar outcome is seen in the case of TransGrid where the premium paid by the 80% high load factor user rises from ~18% in 2006/07 to ~26% in 2013/14 over that of the 30% low load factor user.

2.1.3 Summary of transmission pricing observations

Whilst there is an expectation that there will be some year on year changes above and below the AER allowed X factors to accommodate unders/overs in the previous year, as well as movements in general (non-locational TUoS) prices due the annual variability of settlements residues, there is an expectation that overall trends in prices set on both demand and energy bases will generally follow the AER determinations and be consistent between the two. This is not borne out in either of the TransGrid and Transend pricing.

In addition to variation in trends between energy and demand pricing, there is an expectation that prices for the same service should approximate the general trend for changes in the allowed revenue. This allows greater certainty for consumers in year on year changes for the costs of transmission.

The structure and the freedom granted to transmission networks to develop their prices, even under the strictures of the Rules, still results in considerable variation from the general trends implied by the X factor established by the AER at the revenue reset. This freedom is further exacerbated by the ability of the networks to allow low load factor users to pay their transmission charges on an energy basis which does not recover the costs that are incurred to meet the occasional high demands implicit in low load factor usage.

There are clearly locational signals embedded in the transmission pricing, yet most users do not "see" these signals. This is quite apparent for those users deep in the distribution networks where consumers of the same class have the same prices regardless of their location. But this same lack of locational signal has also been seen by MEU members embedded in distribution closer to the transmission network, such as those connected at subtransmission levels and to zone substations. They do not readily "see" the location signals provided by the transmission network although those users which have specific distribution charges might have these locational signals incorporated into their unique distribution charges but if this is the case, it is neither apparent nor transparent.

The incorporation of the transmission costs into distribution is also a fraught issue as it appears that most distribution networks pay for the common service and general (non-locational TUoS) charges on an energy basis, regardless of the demand that they have at each transmission exit point. This observation is important where transmission common service and general prices are more heavily weighted to recovery of costs on a demand basis.

The review of the transmission tariffs highlights there is some variation between the networks in the approach they take to tariff development.

> Transmission prices, although more closely prescribed by the Rules, still exhibit significant differences, such as:
>
> - AEMO assesses demand based on the 10 peak days in the year to set its prices whereas most TNSPs assess demand over an entire year
> - Some TNSPs use cost reflective network pricing (CRNP) approaches and others use modified CRNP approaches to establish their prices.
> - There are even differences between charging approaches where AEMO seeks to charge for its services based on historic usage applying well into the past, other TNSPs apply the highest demand incurred in the previous 12 months and TransGrid monthly charges are based on the highest demand incurred in the month.
>
> The MEU considers that more care is needed to address the issue of improving cost reflectivity of transmission network pricing and the observations and comments resulting from direct interaction MEU members have had and reported to the MEU, will provide useful in the further investigations by the AEMC in relation to the rule change proposal."

Based on its longitudinal assessment, the MEU is extremely concerned that TN pricing does not reflect the costs for the service provided. The AER has an obligation to ensure there are no anomalies in network pricing through the pricing methodology approval process but the outcomes do not support that this requirement has been achieved.

The MEU notes that TN is essentially retaining its current pricing methodology. Unfortunately the MEU notes that the changes proposed by TransGrid (TG) in its proposed pricing methodology have not been taken up by TN. The MEU considers that TN should change its methodology to be similar to that proposed by TG as the TG approach will deliver a more cost reflective outcome and will address some of the anomalies the MEU has identified occur with the current TN approach.

The MEU considers that the new TG pricing methodology is a major step forward in ensuring transmission costs are shared equitably between all users of the services provided. Therefore the MEU supports the new TG pricing methodology and has noted some changes below that should be made to the TG proposed methodology in order to make the methodology more workable and cost reflective:

1. Setting of peak demands on the peak usage days. TG considers that the peak demand used at any time on the 20 peak days should be the basis of setting the peak demand. The MEU considers that this does not send the appropriate signal to users to limit their usage when the network is most stressed. The MEU notes that AEMO in Victoria sets the peak

usage in the period between 11 am and 7 pm on the 10 system peak days and this provides a clear signal for consumers to limit their usage at peak network usage times. To set the peak demand at any time of the day does not encourage the load shifting which results in higher overall load factors and better capacity utilisation. The proposal by TG will not achieve the goal of deferring augmentation as it assumes that users will limit their usage for considerable periods of time for little benefit to the network and maximum disruption to the user.

2. TG intends to apply the methodology from historical data from the most recent financial year. The MEU considers that a more accurate and contemporary outcome will result from using the most recent 12 month period as AEMO is proposing to do in Victoria.
3. Excess demand charge. The MEU considers that the excess demand charge must reflect the cost the excess demand imposes on the network. If that excess demand can be accommodated because there is excess capacity in the network at that location, the excess demand charge should be zero.
4. TG is the coordinating TNSP in NSW. This means that TG recovers payments for the transmission assets provided by other networks - currently this covers payments to Directlink, Ausgrid and ActewAGL. The MEU considers that only those consumers that benefit from the transmission assets provided by these transmission asset owners should be charged for the use of these assets - under the pricing methodology the costs of these peripheral transmission services is paid by all NSW consumers regardless as to whether they use the assets or not. For example, the ActewAGL transmission assets only benefit ActewAGL customers in the ACT - it is inequitable that consumers in (say) northern NSW should be required to cross subsidise ActewAGL customers in this fashion.
5. There is no clarity on what costs are to be allocated to what service. For example, some services currently included on common services (CS) should be allocated to transmission use of service (TUoS) charges. TG currently has all maintenance costs included in CS yet the cost of maintenance is related to the provision of network assets and should be part of TUoS. The MEU considers that all network related costs should be included in TUoS. TG has commented that as maintenance costs vary by location over time, they cannot allocate these costs accurately. The MEU disagrees. Currently depreciation of network assets is "smeared" across all network assets to avoid price shocks when an asset is replaced. In a similar way, network maintenance can be "smeared" over network costs to reflect the true costs of TUoS. Common services should be exactly that - only be those services which a common to all users such as network planning and operation, and overheads.

Whilst the MEU has provided these views on the pricing methodology proposed, the MEU considers there are still more changes that should be applied in order to get a more equitable outcome.

The MEU considers that TN should be required to revise its pricing methodology to reflect the new TransGrid approach but modified to incorporate the changes noted above and that TN be required to carry out more consultation with its customers to improve its pricing methodology, taking into account the MEU's suggested changes above.

10.1 AER questions

Whilst only one question (#3) is directly applicable to the TN proposal, the MEU has included its responses to the questions relating to the TransGrid proposed pricing methodology. The MEU has done this as it considers that TN pricing methodology needs to be changed to one similar to the TransGrid pricing proposal.

#	AER question	MEU response
1	TransGrid has proposed an alternative pricing structure for locational prices. That is, rather than putting forward a structure expressly permitted in the pricing methodology guidelines, it has proposed its own alternative (20-day peak method). The pricing methodology guidelines allow for alternative pricing structures where they give effect to the NER, improve on the permitted pricing structures, and contribute to the national electricity objective. Do stakeholders consider the '20-day peak method' which TransGrid has proposed meets those requirements?	The MEU considers that the proposal is a "step in the right direction" and follows the lead provided by AEMO in transmission pricing in Victoria. However, as noted above, the TG proposal does not result in the most efficient method to get consumers to use the network in the most efficient manner - such as load shifting to times of lower demand or to limit their demand when the network is most stressed by avoiding the known peak times when networks are most used[18]. The MEU considers that the peak usage should be measured between 11 am and 7 pm on peak system days as applies in Victoria.
2	Do you support the specific proposals by TransGrid to promote greater stability in annual transmission charges?	A qualified "yes" provided other changes are made to ensure there is greater cost reflectivity and incentives for consumers to modify their usage pattern to minimise the stress on the network. See comments above

[18] such as in the afternoons of high temperature days

3	TasNetworks has proposed the introduction of standby provisions in its pricing methodology. Do stakeholders have any comments regarding those arrangements and the process by which TasNetworks has stated it will agree to them?	The MEU considers that the standby provisions provide a benefit for those consumers that have their own generation (as the standby provision allows the time for maintenance of the generation plant) and for those consumers where they have the ability to load shed at will. What is absent form the arrangements is the process by which TN will advise consumers as to when the network is loaded to a level such that the provision of stanndby services will not be allowed. The MEU considers that TN must provide guidance as to when it considers that the standby will not be avialble and how this will be communicated to the customer. The MEU notes that TN intends to apply an excess demand charge. The MEU considers that this has to be addressed as part of the standby provisions. The intent of the standby provision is to allow non-firm access to greater supply capacity at times when the network is not loaded to its rated capacity. The excess demand charge should not apply when the customer's demand does not impose a load on the network that does not exceed the network capacity or causes another customer to shed load. Effectively, the excess demand charge should not apply when there is spare capacity in the net for the additional load imposed.

Appendix 1

Five-year drop for commodities' prices

Australian Financial Review: : PUBLISHED: 16 Jul 2014 18:15:24 | UPDATED: 17 Jul 2014 03:07:08PRINT EDITION: 16 Jul 2014

Commodities from iron ore to copper and Brent crude will drop over the next five years as global supplies climb, according to Goldman Sachs Group, which highlighted oil's recent losses as a sign of increased output.

There will be substantial declines in some metals, energy and bulk commodities, analysts including chief currency strategist Robin Brooks wrote in a report. The period of continued year-on-year price rises for most commodities is over, they said in the report, which was dated yesterday.

Banks from Citigroup to Deutsche Bank have called an end to the commodities super-cycle, when China's surging demand combined with supply constraints led to a doubling of prices in the 12 years through 2010.
Raw materials rallied this year from three annual losses as a lack of rain in Brazil lifted coffee and a ban of ore exports from Indonesia spurred a rally in nickel. The drop in energy prices since last month showed the impact of higher global output, Goldman said in its report.

"A prolonged period of elevated commodity prices has catalysed a supply response," the analysts wrote. "We do not expect a collapse in global commodity prices. But we do anticipate substantial declines."

Copper was forecast to drop to $US6600 a metric tonne over five years, while iron ore was seen at $US80 a tonne and Brent may be $US100 a barrel, according to Goldman. The steel-making raw material was at $US98 a dry tonne in China, Tuesday, and copper traded at $US7122 on the London Metal Exchange on Wednesday. Brent was US34¢ higher at $US106.36 on the ICE Futures Europe.

'Looser supply'

The Bloomberg Commodity Index of 22 raw materials climbed 3.2 per cent this year. That compares with a 1 per cent drop in the Bloomberg Dollar Spot Index and 5.1 per cent advance in the MSCI All-Country World Index of equities.

"Against a looser supply backdrop, commodity prices should be much less sensitive to fluctuations in global growth than they were," Goldman said in the report, entitled *Emerging Market Forex and the End of the Commodity Market Super-Cycle*.

Goldman said in a January report the cycle that spurred higher commodities prices is reversing as increased US shale oil output keeps energy prices low, and that would eventually drive raw materials into a bear market. The new cycle is the opposite of the super-cycle, it said then.

“We remain bearish on iron ore, and expect a surplus market to drive the longer-term price down,” the Goldman analysts wrote in Tuesday’s report. “We see limited upside for agricultural commodities over the longer run.”

Ore output

Rio Tinto Group, the world’s second-largest mining company, said today that iron ore production in the three months to June increased 11 per cent, while Fortescue Metals Group said its shipments were 57 per cent higher on year. Iron ore entered a bear market in March on prospects for a glut as supplies surged.

Brent crude rallied to as much as $US115.71 a barrel last month as military gains in Iraq by an al-Qaeda breakaway group stoked concern that oil supplies may be disrupted. Prices posted a third weekly loss in the period to July 11, with Iraqi shipments unaffected and Libya moving to boost exports.

“Less than a month has passed since geopolitical risks in Iraq pushed up oil prices on concerns over a potential oil supply shock, and the market seems to have absorbed the related risks reasonably well,” Goldman analysts wrote. “The expansion in oil supply over the past few years -- primarily from the expansion of US shale production – has minimised the consequences from past disruptions in Libya and Iraq.”

Record volumes

US production of crude, along with liquids separated from natural gas, surpassed all other countries this year with daily output exceeding 11 million barrels in the first quarter, Bank of America Corp said in a report July 4. Output has climbed as hydraulic fracturing and horizontal drilling help producers pull record volumes of crude out of shale formations.
Deutsche Bank said last month commodity prices will remain subdued for years as many of the factors and fears that drove the super-cycle have dissipated. Citigroup said in April 2013 that death bells would ring for the commodity super-cycle.

“Our long-term commodity forecasts suggest that fundamentals for commodity currencies will deteriorate,” the Goldman analysts wrote. “Relative shifts in terms of trade between commodity importers and exporters will be a key input to currency determination over the coming years.”

Bloomberg

See
http://www.afr.com/p/markets/five_year_drop_for_commodities_prices_uK3AfUNPMB08PMXD2arAoJ