Australian Energy Regulator

NSW Electricity Transmission Revenue Reset

TransGrid Application

A response

by

The Energy Markets Reform Forum

July 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.

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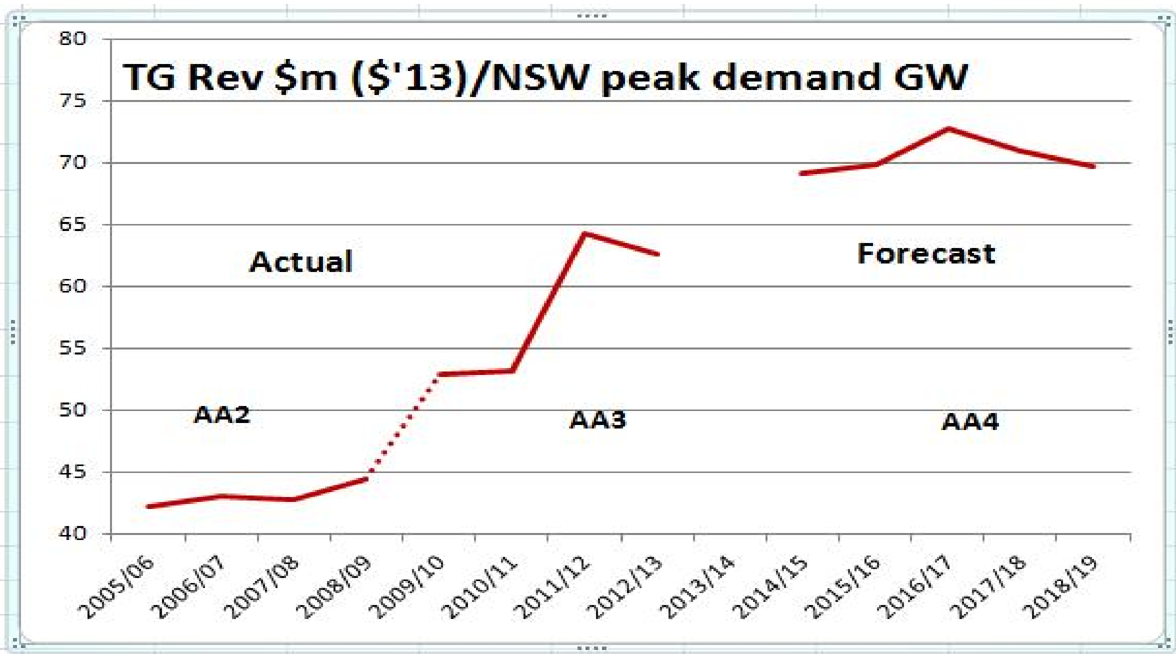
Executive Summary

The Energy Markets Reform Forum (EMRF) welcomes the opportunity for presenting its views on the application from TransGrid (TG) for a reset of the electricity transmission costs in NSW.

The EMRF notes that the proposal from TG results in an increase in allowed revenue from the current levels. The EMRF considers that TG revenue should fall from its current level, not increase. The EMRF notes that as demand is the main driver of a network's cost, when TG revenue is assessed on the expected peak demands for the forecast period (AA4), then its costs per GW are increasing at an considerably, even higher than the similar costs in the current period (AA3), and at a massive premium to the costs assessed on this basis for AA2



Source: TG economic expenditure RIN, AEMO June '14 NEFR, TG application

On this comparative basis, it is clear that the TG proposal for its revenue is significantly overstated.

The EMRF has investigated the reasons why TG revenue shows such an increase when falling demand and consumption would imply a need for less revenue. In its assessment the EMRF noted that:

- TG has grossly overstated its weighted average cost of capital and considers that the AER guideline on setting the rates of return on equity and debt are wrong and do not deliver the returns that TG considers are appropriate. That the claims of TG would deliver it a return on equity greater than many firms facing considerably more risk gain is ignored by TG in its assessment. Further, TG claims a much greater cost of debt than it actually incurs is also disregarded. The EMRF finds these views totally inconsistent with reality and at odds with the TG assertions that it seeks to reduce the imposts on consumers for providing network services.

- The EMRF has reviewed the TG claims for opex and considers that TG has grossly overstated its requirements. It has minimized what the efficiency benefit sharing scheme is supposed to achieve for consumers by limiting the impact of the revealed cost approach to opex. Its claimed step changes are overstated and overpriced.

- TG recognises that its need for network augmentation had to reduce because of the falling demand and consumption of electricity in NSW yet it still seeks to augment parts of the network. The fall in forecast augmentation capex is offset by significant increases in replacement capex for which it seeks considerable increases from the replacement capex considered adequate in the previous two periods (AA2 and AA3).

- The Network Capability Incentive Parameter Action Plan (NCIPAP) proposal by TG is seen as a "grab for money" with most of its projects either being work that TG should have done under its normal opex/capex programs or delivering benefits over 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 anticipated. Further, the ranking of projects is at odds with a scheme that is intended to deliver benefits to consumers in the short term.

- The pricing methodology is likely to result in greater cost reflectivity yet still does not address some basic concerns that a better formulated methodology would achieve.

Overall, the TG 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 network services. The EMRF expected that the TG proposal would result in considerable reductions but what has been provided by TG is more of the same increases that brought network services regulation into dispute since 2011.

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

1. Introduction

1.1 The EMRF

The Energy Markets Reform Forum (EMRF) is a group representing large energy consumers in NSW. The EMRF is an affiliate of the Major Energy Users Inc (MEU), which together comprise some 20 major energy using companies in NSW, NSW, SA, WA, NT, Tasmania and Queensland.

The EMRF welcomes the opportunity to provide comments on the application for a revenue reset for the NSW electricity transmission system by TransGrid (TG).

Analysis of the electricity usage by the members of EMRF shows that in aggregate they consume a significant proportion of the electricity generated in NSW. 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 EMRF (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. 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 EMRF 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, EMRF (and its affiliate MEU) are 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 EMRF 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 EMRF had actively participated in previous Australian Energy Regulator (AER) pricing and revenue reviews of the NSW transmission and distribution networks, it was not contacted by TG to discuss its current application despite MEU representing a significant number of large energy users.

It is noted that TG did eventually have discussions with EMRF about its proposal but this subsequent to the development of the proposal. Given these are challenging times for energy consumers nationally, it is of the utmost importance that TG ensures that it is actively engaging, and adopting the views of its consumers.

The EMRF remains available for consultations with TransGrid.

1.2 The scope of this review

The EMRF 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 in 2006 and 2007 following the promulgation of significantly unbalanced rules by the Australian Energy Market Commission (AEMC) pertaining to the transmission network rules (chapter 6A) which (in conjunction with the distribution rules that followed the transmission rules) have very substantially disadvantaged consumer interests and resulted in much economic and social hardship.

Since then, Chapter 6A has been significantly revised with the AER development of new guidelines to implement the new rules. It is noted that TG has elected to accept some of the new guidelines but reject others.

This is extremely concerning and the new guidelines were developed after wide consultation and with significant consumer input. Consumers have stated that they consider some of the guidelines do not address their concerns yet, despite this, they have accepted the guidelines as they stand. That TG insists on "raking over old ground" in an attempt to get a better outcome for themselves, is disappointing.

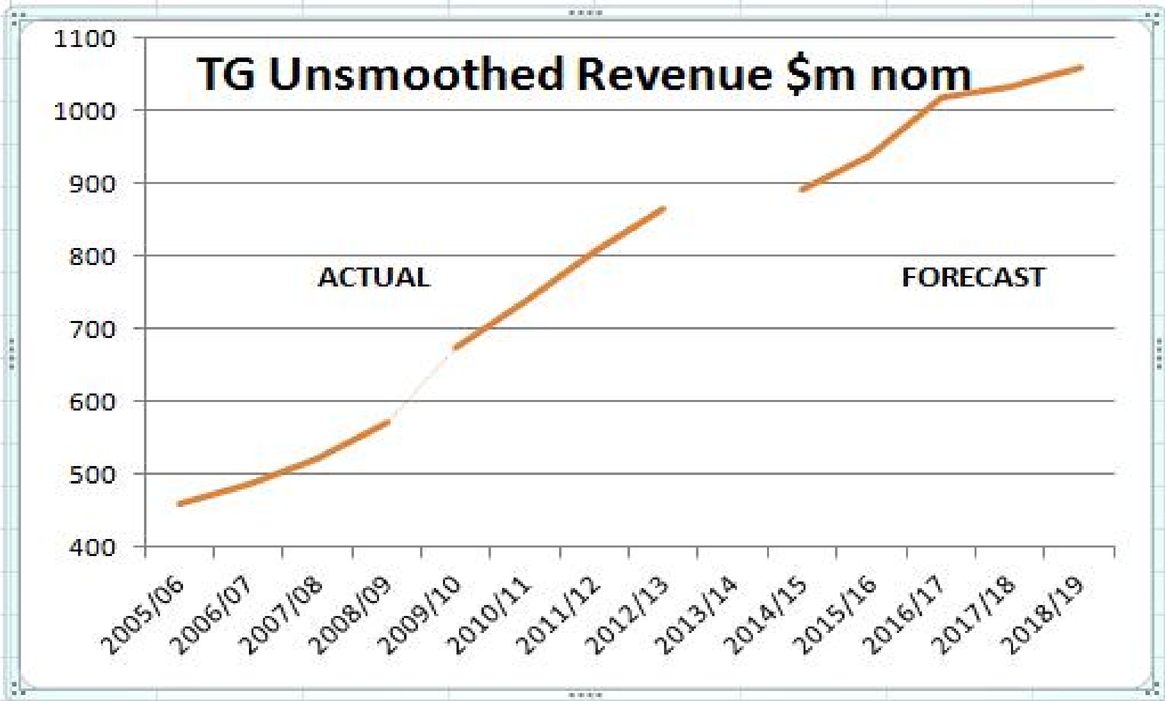
This behavior by TG does not reflect the assertions that TG is aware of the stresses that consumers face and that it is seeking to reduce the costs for the service it provides. Essentially, it appears that TG is attempting to subvert the goals of the recent reforms of network regulation.

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 were used efficiently, the AER has the responsibility to ensure that the funds are acquired in a way that provides 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 so they are incentivised to take actions so that the network can be operated more efficiently and that the assets have maximum utilization. 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.

1.3 A summary view of the TG application

TG has forecast a revenue requirement that reflects the massive increases seen during the current period AA3 and that the revenue forecast for AA4 an even higher revenue requirement than seen even in the final years of AA3



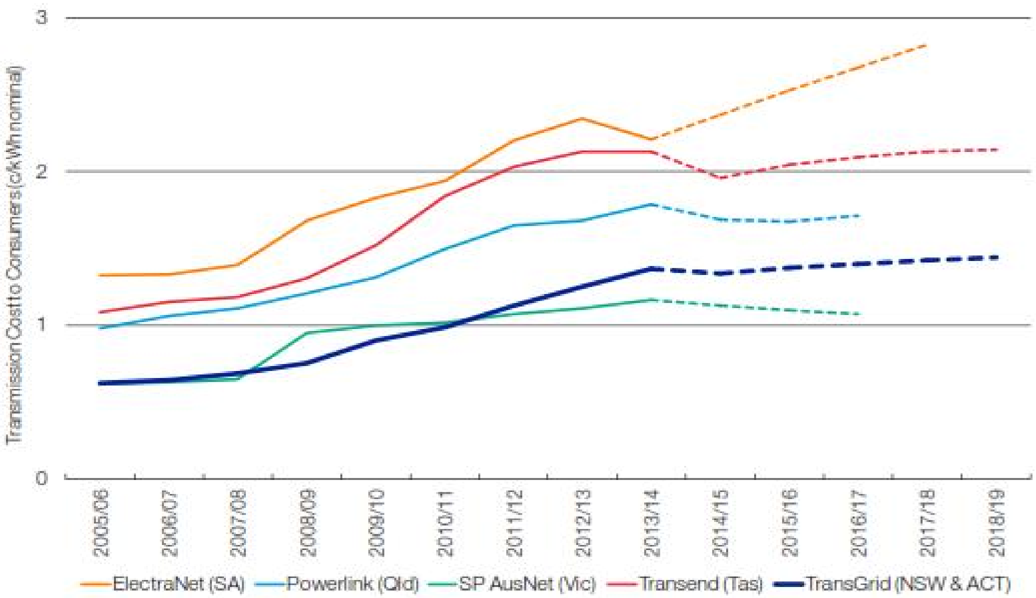
Source: TG application, TG benchmarking RIN

The EMRF considers that the approach to the revenue reset used by TG has "locked in" the excessive cost claims made by TG for AA3 and shows that the assertions made by TG that it has addressed its cost structures to implement savings is so much hollow rhetoric.

To demonstrate that its network costs are efficient, it has stated that its costs will increase at less than CPI for the next five years This assertion is beset with a very large assumption - that of the expected growth (or not) of the consumption of electricity and the expected growth in demand. If consumption continues its current downward trend, then the cost per unit of consumption (MWh) will continue to increase. The massive increase in prices during the current period (AA3) reflects the massive increase in revenue allowed at the last reset and the unanticipated (at the time) collapse of traditional increases in demand and consumption.

TG has provided a view in the following chart of the cost of its services relative to the growth in consumption are efficient by comparing its costs in terms of volumes of electricity used with transmission service providers in other regions. What this does not show is that TG costs should be much lower than most due to its unique features.

Figure 2.2
Transmission Cost to Consumers



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

The two aspects that this figure shows is that TG, previously the lowest cost provider of electricity transmission in the NEM, is now the second least expensive and is heading towards matching prices with Powerlink in Queensland. In comparative terms, whereas TG and SP AusNet in Victoria had much the same pricing, TG pricing is diverging significantly from that available in Victoria

It also highlights that the historic cost of ~$7/MWh in 2007/08 will rise by a staggering 200% in the past 6 years and will rise further under the revenue stream proposed by TG. In comparison, price rises in all other transmission network service providers (TNSPs) have increased at much lower rates in percentage terms.

In 2009, the EMRF pointed out in its response to the TG application for the current period, that TG 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 and demand and consumption fell considerably, providing TG with considerable revenue that it did not require. It is the view of the EMRF that the revenue which was acquired unnecessarily must be considered within this proposal, and taken into consideration when TG is making claim for gross increase in their pricing structure to reflect capex. This windfall of revenue should have been reallocated back to the consumer rather than delivered to TG shareholders.

The AER therefore needs to assess this application on the basis that the cost rise in the last period (AA3) was demonstrably excessive.

Implicit in the TG application is a continuing trend of increasing revenues which when balanced by a declining trend in demand and consumption would appear to be inconsistent and fails to recognise the fact that its cost structure is massively above (in proportional terms) what it was before the current reset period.

In fact, the only area where TG forecasts a reduction in its cost structure for the next period, is in the amount of actual capex forecast compared to actual capex in the current period. Further, TG has under-run significantly both its opex and capex the regulatory allowances during the current period yet its revenue take continued to massively increase. This disparity demonstrates the opportunistic manner in which TG operated within AA3 period, and highlights the intentions within the proposal in AA4 to unnecessarily increase their revenue for AA4 which adds further undue pressure on consumers..

Overall, the EMRF would have expected considerably lower costs for the next period, rather than the continuation of the growth in the current excessively high costs seen at the moment.

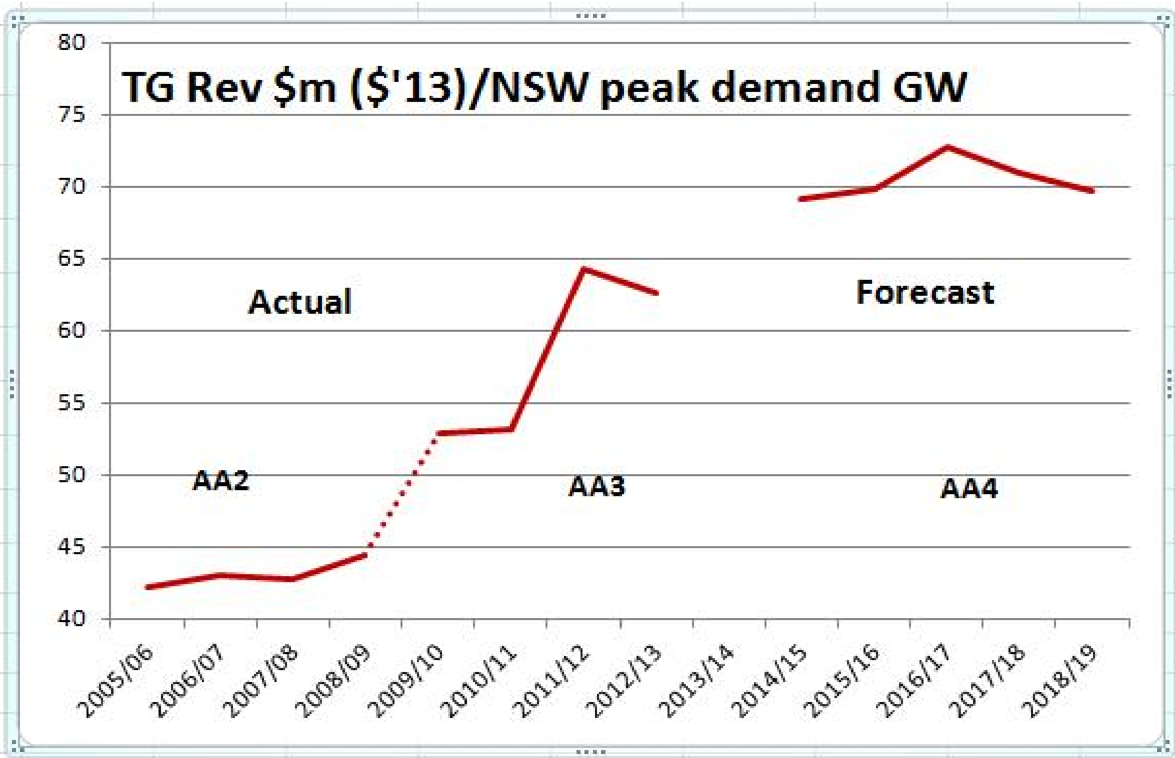
Against this background, we consider that the AER has a clear responsibility to ensure a certain amount of discipline is placed on TG and that all claimed costs can be justified and are economically efficient. The EMRF would expect that given the under-runs in both capex and opex allowances in the current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

1.4 The helicopter view

TG indicates that its revenue will increase in the next period (AA4) above the revenue that it had in previous periods. The EMRF is unable to accept that the proposed maintenance of costs can be justified when assessed against a background and a foreground of falling consumption and demand, continuing a trend where costs are increasing despite falling demand and consumption.

Equally, we note that TG has provided arguments in support of each element of its claimed cost increases. In a competitive world, senior management of a business must and does take a view that any claimed increase in cost must be controlled in light of the potential implications for the firm's competitive position. In the regulated energy sector, however, legislation has provided the AER with the role of providing this discipline, and so it must ensure that the resultant outcomes are in keeping with what can be expected from the discipline of efficient drivers.

The EMRF recognizes that TG costs are driven by the peak demands that consumers impose on the region. To assess the TG application the EMRF has calculated actual and forecast TG revenue (adjusted for inflation) and divided this by the actual NSW peak demand and the forecast (50% PoE) in the June 2014 National Electricity Forecasting Report (NEFR) for NSW. This is shown in the following chart



Source: TG economic expenditure RIN, AEMO June '14 NEFR, TG application

What the above clearly demonstrates is the impact of the falling demand since 2008/09 and the impact of the low demand and the increased revenue sought by TG for the next period (AA4). Whilst there is some rationale for the increased costs for the current period (AA3) as there was forecast for an increasing demand when TG commenced AA3, there is no excuse for continuing this trend now that the forecasts of demand are much lower than those underpinning the AA3 revenue allowances. The EMRF 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, an increase in selling prices of nearly 50% between AA2 and AA3 could not be sustained by any competitive business against an environment of falling consumption. This fact demonstrates the absolute monopoly which TG has in the NSW energy market, and the ability for TG to adjust its pricing structure to reflect the interests of the organization and its shareholder, and not those of consumers. It is clear that TG sees this revenue reset process as an opportunity to maximise its rewards as a monopoly service provider.

For TG to consider that a further increase should be funded by consumers for another 5 years is unreal and must not be approved.

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.

On page 18 of its application, TG states that its costs are the smallest element of the average household bill. The implication of this comment is that, being only a small element of the overall cost, it should be recognised as not being a contributor to the massive rises in electricity prices seen over the current regulatory period. Such an observation is dissembling as on page 19, TG comments:

> "The transmission sector [in NSW] has not seen the double-digit percentage price increases that some other sectors have over the last five years."

This observation is totally misleading. Some EMRF members have seen transmission prices triple since 2007/08 - an average annual increase of some 20% per annum and have suffered considerably because of these price rises.

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; it is imperative that TG addresses this issue adequately as part of its proposal.

1.6 Consumer engagement and AER questions

The EMRF 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.

TransGrid noted that it has increased its customer and consumer engagement and points to the meetings with a small sample of the users of its services it has had explaining, amongst other things, its expenditure forecasts, revenue impacts and pricing methodology. TransGrid comments that such consultations have resulted in some planned capex being reviewed for deferral.

The EMRF is pleased that this engagement has occurred. However the EMRF has significant concerns that such interaction still consists more of "this is what we have planned" and "the reliability and availability is this and this is what it costs" rather than "how can we provide the service you need which meets your ability to pay". This concern is evidenced by TransGrid's observation (page 39)

> "Almost two thirds of participants indicated that they were willing to pay a slight increase of around $4 per annum, which is within CPI, to maintain the same reliability as now. Almost one third advised that they would prefer to pay the same as now and accept slightly more blackouts, and a small number would prefer to pay slightly less than now and accept more blackouts."

The clear import of this is that consumers will pay TransGrid an additional $4 pa for better reliability yet TransGrid has not provided data as to how much reliability would suffer if TransGrid were to offer lower prices. Therefore, the premise of their question is misleading, and the EMRF is concerned that it is an intentional ploy to justify price increases under the guise of consumer approval.

Additionally, the EMRF recognises that it is primarily the distribution networks that cause the poor reliability to most consumers rather than TG. The EMRF is also concerned that consumers are unaware that TG is increasing its charges by more than the $4 pa just to provide the same level of service.

The EMRF notes that TG proposes to increase its demand management innovation allowance which increases costs to consumers yet there is some uncertainty as to whether this increased cost will deliver benefits to the consumers that fund this additional work. The AER should investigate whether this increased allowance should be permitted as there has been no detailed assessment of the benefits (if any).

In conjunction with the above, TG is also seeking additional funding to address consumer engagement. Whether the increased costs will deliver better outcomes is still to be demonstrated.

Although the EMRF is concerned about the detail and approach by TG, the EMRF recognises that the consumer engagement process will, hopefully, improve over time, to the benefit of both consumers and TransGrid. However, it the EMRF and its affiliates contend that this program should be funded through existing revenue, and not be used as an opportunity by TG to raise their prices unnecessarily.

TG advises (page 5)

> "TransGrid has established a comprehensive consumer engagement program, to give consumers a voice in the development of TransGrid's business plans and ensure that the revenue proposal takes into consideration consumers' perspectives and priorities."

TG adds this was achieved through consumer workshops held with residential consumers, small and large business, industrial and commercial customers and a range of consumer representative groups where discussions focused on a range of topics, including demand management, incentive schemes, pricing methodology and rate of return. Detailed analysis of the consumer workshops shows that these were limited to three in number with no more than 4 hours duration dedicated each to the workshop with a consumer attendance ranging from 9 to 27. Additionally two large user roundtables were held lasting no more than 6 hours with an average of 12 attendees. TG also had a survey carried out with 650 respondents which took some 20 minutes to complete.

What is not made clear is that four of these consumer contacts were made in mid to late November 2013 with another in April 2014, the survey carried out in March 2014 and face to face contacts in late March 2014. From these TG provides support for its programs and many of their claims within their proposal. As these consumer contacts were made so close to the deadline for their reset proposal, the EMRF has concerns about the how much of the input generated within these events were used when completing their proposal.

The above clearly implies that the consumer engagement had much less to do with providing the basis for the TG proposal than providing justification for decisions already made. As such, the EMRF might conclude that the TG consumer engagement program to date has been "window dressing".

This issue is particularly important when assessing the TG claims for increased opex and capex. In each of the sections in the application dealing with opex and capex, TG makes reference to the outcomes from the consumer engagement undertaken and from these seems to identify support for the proposals it makes. The EMRF has considerable concern with this as the timing of the consumer engagement would have precluded many of the decisions being influence by the consumer feedback.

At a high level, TG appears to have "ticked all the boxes" expected for a consumer engagement program, utilizing a range of social research methodologies. However, the execution has flaws as highlighted above. Not unexpectedly, many of the TG assertions that it supposedly generated from this program support the company's interests.

One area where the EMRF did consider TG undertook good consumer engagement was in relation to its pricing methodology. In this case, TG released a consultation paper on transmission pricing to assist consumers understand the detail of how pricing is undertaken and sought feedback from consumers in order to develop its pricing methodology. The EMRF comments on the detail of the pricing methodology are addressed later in this submission.

While accepting that the TG engagement program is better than what TG has done in the past, the EMRF considers that the amount of time needed to explain to the attendees what TG 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 EMRF is that it is well short of the time needed to fully understand what TG does, the costs it charges for the service it provides and whether consumers are getting value for money.

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

	AER question	**EMRF response**
1	What is your view on the accessibility of the TG information provided	TG has provided a separate website (yoursaytransgrid) for consumers to get greater knowledge and provide input to TG activities but the EMRF queries whether access to the TG website would be the initial approach taken by consumers. Having two different website increases confusion.
2	What was your role in the engagement process and what were the objectives of the engagement	Some EMRF members report that they attended some of the TG engagement processes. The EMRF itself was not advised of the early engagement functions. EMRF members report that they attended with the desire to learn more. The EMRF cannot comment on what the TG objectives were.
3	How much time was provided between the engagement activity and the application being finalised.	The EMRF considers that the time frames would have precluded consumer views having much impact on the detailed development of the proposal

4	If you were consulted as part of the consumer engagement undertaken by TG 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 EMRF did not attend the TG engagement functions but members report that the forums were more about TG providing their views than about detailed discussions about the issues.
5	Please provide any comments on how effective you believe the consumer engagement conducted by TG 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).	EMRF members who attended the TG forums report that their comments would have had little impact on the revenue proposal. However EMRF can report that the TG pricing methodology did reflect considerable consumer input

1.7 Regulatory control period

TG has proposed as part of its revenue reset application that its regulatory control period be reduced from 5 years to 4 years. The reason for this change as asserted within the document is that it would assist in leading to bringing all TNSPs to a common revenue review date as contemplated by AEMC when it developed the new rules for network regulation.

The EMRF identifies a number of issues in relation to this proposal

Firstly, the current timings for the NSW network reviews has TG and its four related distribution networks (Ausgrid, Endeavour, Essential and ActewAGL) being reviewed concurrently. This provides an ability for the regulator to assess the interconnection requirements between TG and its main customers. In contrast, the move to a four year regulatory control period would prevent this occurring at the next review.

Secondly, a 4 year regulatory period would not result in more TNSPs being reviewed concurrently, but would increase the separation as the review of Transend would then be the only TNSP being reviewed over the year 2018 and TG and ElectraNet would be reviewed in the same year of 2017. TG proposes that a further foreshortened period would apply the following regulatory period to align with Powerlink and SP AusNet. Both Powerlink and SP AusNet would be reviewed in the year 2016, noting that SP AusNet new regulatory period commences in April and Powerlink in July of 2017.

Thirdly, the EMRF does not consider that the AEMC concept of concurrent TNSP reviews, whilst having some benefits, is feasible from a resourcing viewpoint for the AER and other stakeholders. The EMRF considers that the contemplated benefits of concurrent TNSP reviews can be achieved in other ways. In particular,

- The assistance in cross border planning (interconnectors) does not require concurrent reviews (as the recent approval of the SAVic augmentation shows

- Concurrent reviews is not required for better benchmarking - in fact the EMRF considers non-concurrent reviews will provide a better ability to transfer the benefits of better benchmarking as benchmark data from other TNSPs will be mid regulatory periods and provide a better view of what can be achieved through efficiency gains..

While the new rules do contemplate a move to concurrent reviews, this is not mandatory. The EMRF considers the AER should examine the concept in more depth to assess whether there is a net benefit in bringing all of the TNSP reviews to be concurrent

1.8 Shared assets

The EMRF notes that TG does provide services to others using the assets fully paid for by consumers and therefore consumers should receive a benefit for this additional use.

Unfortunately, TG advises that the reward it gets for providing services to others is less than 1% of the smoothed annual revenue - a benchmark set by the AER on the basis that such a small amount has little bearing on the costs consumers carry. This might well be so, but the benefit TG gets from providing these additional services to its profit line is a much greater proportion of the profits made.

This highlights that TG benefits considerably from using assets paid for by consumers but does not have to share this benefit with consumers. EMRF affiliate Major Energy Users made this point strongly to the AER but its views were not accepted by the AER.

1.9 Interplay between incentive schemes

The EMRF recognises the importance of the incentive schemes for opex, capex and service standards and agrees that now there are a suite of competing incentives covering the three elements a better outcome for consumers should result.

However, the EMRF also points out that the actual setting of the allowances for each of the elements is critical because if the base levels for each element are set at the efficient level then the incentives schemes should drive the most efficient outcomes. Setting the most efficient base levels must be from using those historic performances which have been incentivised. Where there has been no incentive scheme, the AER must apply benchmarking to ensure that the allowance reflects efficient levels.

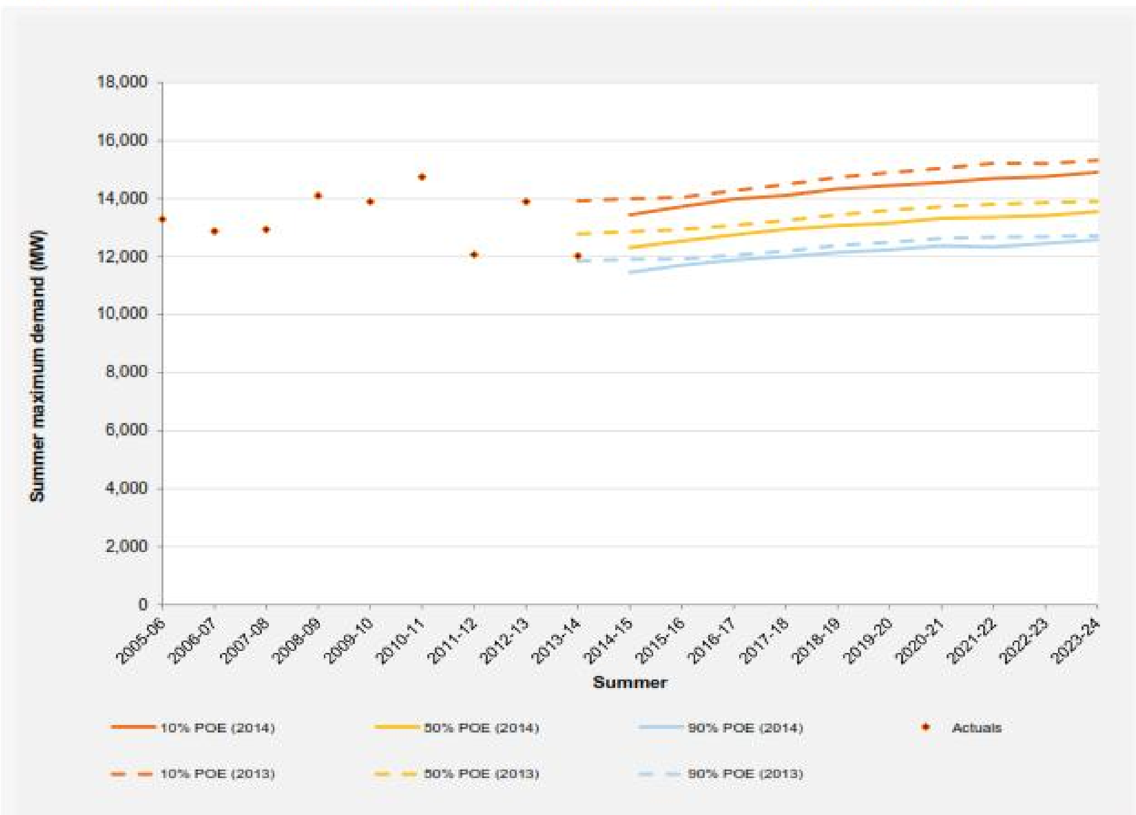
This means that the NSP to benefit it has to work at improvements rather than see bonuses being made available just because it convinced the AER to provide allowances that are more than is efficient.

2. Forecasts of demand, consumption and input cost changes

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

TG is responsible for augmenting the NSW electricity transmission system to meet increases in demand. To provide a view on the needs for augmentation, TG has used the Australian Energy Market Operator (AEMO) 2013 forecast data to provide an overview of the growth in demand expected over the next 5 years. However since that data was released, AEMO has provided the 2014 NEFR which demonstrates that the 2013 data is expected to be overstated. This is shown in the following chart.

Figure 12 — Summer 90%, 50% and 10% POE maximum demand forecasts for New South Wales



The peak demand recorded in NSW was 14.58 GW on 1 February 2011. AEMO forecast is that even on a 10% PoE, this demand will not be exceeded until 2021/20. This provides a prima facie case that there is no need at all for TG to augment its network during the coming period. Equally, the EMRF 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 EMRF is unaware of any such cases.

On a consumption basis, TG experienced a maximum consumption of 78.7 TWh in 2008/09 year, and AEMO (in the 2014 NEFR) is not forecasting this volume to be exceeded in NSW until beyond 2023/24 even under a high growth scenario.

However, what is concerning is that with the reducing consumption and demand that is being experienced, the prices for transmission services will have to increase per unit to allow TG to recover the ever increasing revenue that it is forecasting. The EMRF notes that TG is forecasting a slightly declining average price path (in constant dollar terms). With increasing revenue and falling consumption (2014 NEFR low growth forecast) or flat consumption (2014 NEFR medium growth forecast) the EMRF cannot see how TG can be forecasting a declining average price path. This implies that TG is dissembling in regard to the price impacts on consumers of its revenue ambit claim.

2.2 Escalation forecasts for labour and materials

2.2.1 Wages cost growth

> TG expresses a preference for using BIS Shrapnel (BIS) calculated average weekly earnings (AWE) as the basis for general movements in labour.
>
> TG observes that 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.
>
> Despite its preference for AWE, TG opts for a BIS Shrapnel calculated its own LPI which is not productivity adjusted. In this regard, the EMRF 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. The EMRF supports such an approach.
>
> 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 to seek the elimination of the waste services element of the index. However, the EMRF notes that TG has accepted previous AER decisions and not sought the exclusion of the waste services element.

The EMRF is concerned that the forecasts made by BIS have exhibited considerable variation to actual outcomes when compared to those made by DAE. The fact that there are significant variances between forecasts and actuals (more often in overstating future movements 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, TG has opted for this labour cost element to be escalated using the TG employee agreement. The EMRF considers this is inappropriate. The EMRF 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 EMRF considers that:

- Capex and outsourced labour costs should be adjusted for forecast movements in the DAE construction LPI
- TG direct labour costs should be adjusted for forecast movements in the DAE EGWW labour LPI
- 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, TG has not provided adequate reasons for change from AER practice in its proposal.

2.2.2 Materials cost growth

TG provides a report from SKM providing a forecast of the movements in certain materials, and the movements in the CPI and $A-$US which adjusts the materials prices to reflect local costs. SKM also provides its views on materials price movements with and without a price on carbon.

The EMRF is concerned that the SKM 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 EMRF provides a report of the Bloomberg view that material 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 TG (and SKM) 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 EMRF 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

TG has assessed the movements in property prices and set escalation rates for the land it owns and for its easements. The EMRF has no problems with using this approach for the value of the land that TG 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 by and later the AER allowed in 2008 (and then adjusted by the Competition Tribunal later that year) when assessing the valuation of easements acquired by ElectraNet, the cost of easements are not related to the cost of land but reflect 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 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 or 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 than to the cost of land

The EMRF 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 EMRF 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

The EMRF considers that the AER should rectify is 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.

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 table of the past performance of Deloitte Access Economics (DAE) and BIS Shrapnel (BIS) in forecasting actual labour movements (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 EMRF 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 EMRFconsiders 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 WACC 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.

- 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 for allowing for variation in input costs would not be ground breaking in the least.

3. TransGrid 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 favoring 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[1]:

> "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 EMRF 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) 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 meet the needs of each party. Despite this, the EMRF considers the outcome is better than the previous approach used by the AER, the ACCC and the jurisdictional regulators.

In particular,

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[1] "High power rates: it's a poles and wires story", SMH June 12, 2012

- The network firms considered that the approach to the development of the return on equity resulted in a lower outcome than they considered necessary[2]. Despite the concerns expressed, the network firms were not able to explain why, if they were getting a lower return on equity than was considered appropriate, why there was still a drive from potential acquirers of network assets to want to invest in the assets and even pay a premium to the regulated asset base.

- Consumers have noted that the market parameters (equity beta and market risk premium) have been set by the AER 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 achieve. 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. This desire for acquisition of network assets **at a premium to the value of the assets[3]** 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. What is now apparent is that the networks

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[2] 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 evidence that a long term 10 year CGS has a much higher value (by 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

[3] 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

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 EMRF accepts that the AER rate of return guideline was developed as a package and sought to balance competing elements to provide an equitable outcome. On this basis, the EMRF accepts that the guideline should be implemented in its entirety and imposed on TG. Failing this, then all aspects should be opened for re-assessment.

3.2 The WACC for TG

In its application, TG observes (page 176):

> "While TransGrid acknowledges that the AER undertook public consultation in the development of the Rate of Return Guideline (Guideline), TransGrid considers there are observed shortcomings in the approach that the AER has determined to setting both the cost of debt and the cost of equity for a benchmark efficient business. TransGrid considers that this revenue proposal is compliant with the Rules, but is not in all aspects consistent with the Guideline."

TG then goes on to accept certain parts of the AER guideline on rate of return but to challenge other parts. In doing so, TG develops a higher value for the WACC than would occur under the AER guideline. This clearly shows that TG is seeking to enhance the returns that it provides to its shareholder.

This is concerning as the AER guideline was completed late in 2013 (and with it were published contemporaneous parameters) and it would be expected that the parameters the AER developed with its guideline would still be valid. TG does not accept that this is the case, especially with regard to the return on equity parameters. Analysis of the changes TG proposes highlights the bias in the WACC outcome:

- **Gearing**. TG accepts the AER guideline on gearing which considers that a network would have 60% debt and 40% equity. In fact TG has 65% debt and 35% equity. The acceptance of the AER guideline provides TG with a significant benefit

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

- **Transition on debt cost methodology**. TG proposes that there be no transition to the new methodology. TG provides considerable argument in favour of its preferred option but perhaps the most telling is that TG notes that imposing the transition approach will

> "…impose a windfall loss of approximately $141 million" (TG application page 185)

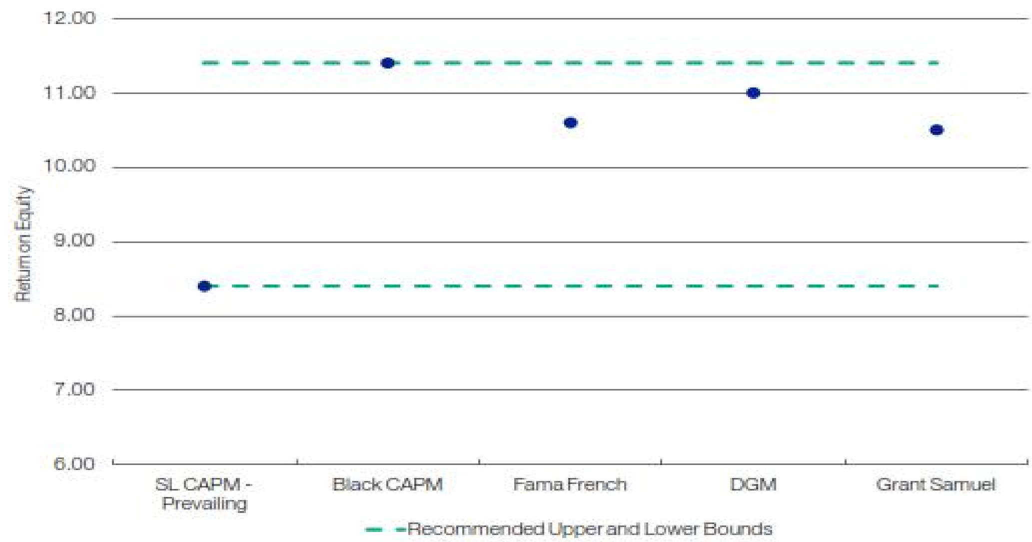
The EMRF affiliate MEU had provided a view to the AER during the Better Regulation process that there was merit in recognising that large energy networks would be able to transition directly to the trailing average approach to setting debt rates, but the AER elected not to follow this approach.

As noted in section 3.1, the EMRF accepts the rate of return guideline as a package. On this basis the EMRF considers the transition to a trailing average approach should be implemented as detailed in the guideline. In particular, the EMRF notes that applying the trailing average approach in full now would result in TG getting a much larger cost of debt than under the guideline. As TG pays considerably less for its debt than even that calculated by the AER guideline, the EMRF considers that consumers will benefit considerably by using the guideline and TG will still more than recover its efficient costs.

3.2.1 Cost of equity modelling.

TG rejects the AER approach to developing the cost of equity observing that the AER approach and current parameters would result in a cost of equity of about 8.4% compared to the average of four other approaches of about 10.8%. TG provided a graphical assessment of the five different approaches

Figure 8.1
Return on Equity Estimates with Upper and Lower Bounds



Source: NERA.

Source: TG application page 189

The arithmetic average of the outcomes of the five different models is 10.4% and TG proposes that the return on equity should be 10.5% - a slight premium to the arithmetic average of all five assessments.

TG rejects the AER foundation model approach for setting the return on equity and discusses at length (both in its proposal and in the accompanying appendix V provided by NERA) three other modeling approaches. What occurs in the TG application is that there is a regurgitation of the arguments put by the networks during the extensive discussions on how to develop a model for setting the cost of equity. That the debate on the use of the other models has been had and conclusions drawn is effectively overlooked. The arguments provided by TG regarding the three additional models do not introduce new information which might lead to a variation in the AER assessment made in the development of its guideline[4].

However, TG (via its appendix V provided by NERA) does provide new information through the Grant Samuel assessment of the valuation of Envestra completed as part of the proposed purchase of Envestra. This seems to imply that a higher return on equity might need to apply than that developed from the AER guideline.

4 The EMRF notes that TG actually remits to its shareholder a return on equity that significantly exceeds the returns considered reasonable by Australian regulators.

What the analysis overlooks as it draws the conclusion that the proposed sale of Envestra implies a return on equity of some 10.5-10.6% based on a cost of debt of 7%. This is intriguing as in the final decision on the Envestra application for revenue in 2010, the AER allowed a return on equity of 10.36% coupled to a cost of debt of 9.37%. These values have underpinned the Envestra cash flow since that time. It is also important to note that the discounted cash flow analysis carried out by Grant Samuel has assisted in the sale value of Envestra to CKI of over a 50% premium to RAB - supporting a view that the returns on equity and debt provided by the AER might well be excessive.

The Grant Samuel report was completed after completion of the AER guidelines (including that on rate of return) were published so it is clear that the assessment by Grant Samuel would have been prepared in the full knowledge of the AER guidelines. This implies that the return on equity would be enhanced above the AER assessment through other aspects of any other profitability that would add to the base allowance of return to shareholders.

3.2.2 Equity beta

The final decision by the AER on the rate of return guideline calculates an equity beta of 0.7 to be used based on evidence available to it at the time. 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 Prof 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 EMRF notes that the MEU 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, there is a clear indication that the benchmark efficient entity would have its equity beta closer to the median value than the average value. A median value identifies the most common value for equity beta for Australian networks recognising the uniqueness of the Australian energy market and its regulatory environment.

The EMRF considers that the work carried out by Prof Henry is more relevant and contemporaneous than the assessments provided by the DBs and CEG and should lead the AER to use a lower equity beta than 0.7..

The EMRF notes that the AER seems to have assessed the claimed TG return on equity calculation as using an equity beta of 0.58 (along with an MRP of 7.26%) in its development of the TG return on equity using the S-L CAPM return on equity. When setting the allowed return on equity for TG, the EMRF considers that the AER should use values consistent with its guideline

3.2.3 Corporate bond rate

TG proposes that the debt be acquired on a corporate bond series rated BBB from the RBA based on the 10 year trailing average without implementing the transition process that underpins the AER guideline. This approach provides the calculation with the full benefit of the GFC where bond rates exceeded 13% compared to the current value of less than 6%.

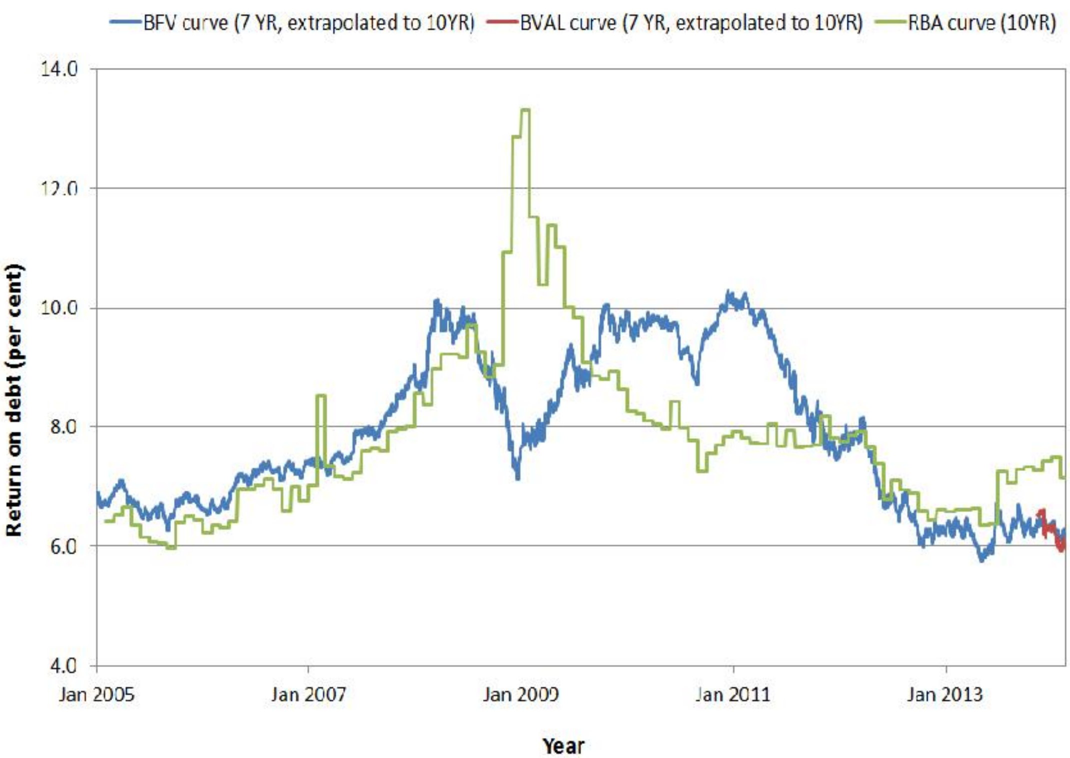
During the GFC (when bond rates soared) TG annual report shows that it paid about 5.5% for its borrowings and its current rate is not much higher. For TG to claim that it entitled to claim an average trailing average cost of debt of 7.72% is clearly a gross overstatement of what TG actually incurred for its cost of debt over that time and it is achieved by TG deciding that it should avoid the transition approach in the AER guideline. In contrast, using the AER guideline, TG would have a cost of debt similar to what it currently pays, even based on it acquiring debt over a number of years which the trailing average approach is supposed to replicate. For TG to assert that using the guideline in lieu of an immediate transition to the trailing average approach and that it would cost TG some $141m is therefore quite disingenuous when in fact the AER guideline would allow TG a return on debt that still exceeds the costs it incurs.

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 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 - 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.

It is not surprising that TG has settled on using the RBA data series combined with an immediate move to the trailing average approach. 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 will provide a clear benefit to TG. It is less clear whether the RBA data series provides a better outcome for TG 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.

Whilst there appears to be a clear differential of up to 100 bp between the RBA and Bloomberg series in the chart above, the EMRF notes that the RBA series has fallen dramatically in the months since the figure was developed and now shows a value below 6% - the EMRF 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. The EMRF considers that both sets of data should be used and averaged as recommended by the Competition Tribunal.

3.2.4 Value of imputation credits

TG has sought for the value of imputation credits (gamma) to remain at the level set by the Competition Tribunal - ie at 0.25. In the Better Regulation program, the AER carried out further investigation and 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. In contrast a utilisation rate of notionally 0.35 was accepted by the Competition Tribunal as an appropriate estimate.

3.2.5 Conclusions

The EMRF 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 EMRF supports using the guideline in its entirety rather than "cherry picking" aspects which favour one stakeholder over another. On this basis the EMRF considers that gamma should be 0.5 as assessed by the AER in its Better Regulation program.

3.3 AER questions on WACC

	AER questions	EMRF response
1	Do you have any comments on the businesses proposed departures from our guideline?	Yes. As noted above, the EMRF 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. 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.
2	Do you consider the approach in our guideline of	As noted above, the EMRF observes that the MEU had supported an immediate transition to the trailing average approach to setting

	transitioning into the new benchmark approach to the return on debt, or TransGrid's proposal for an immediate transition, is appropriate?	debt. However, the rate of return is a complete package and changing one element within the package destroys the inherent balance of the package. On this basis the EMRF supports the AER view that a transition is required to implement the trailing average approach to debt.
3	Do you consider the value in the AER's guideline (0.5) or TransGrid's proposal (0.25) provide a more appropriate approach to estimating the value of imputation credits?	The EMRF supports the AER approach to setting "gamma". As noted above, the EMRF 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 recognises 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 TG 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 EMRF accepts these should continue on the basis of previous AER acceptance.

The EMRF 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 EMRF 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.

In addition to these previously accepted pass throughs, TG seeks to add further pass through events including insurer's credit risk event, cyber-related external attacks and gradual environmental contamination.

The reason for rejecting these additional pass throughs is that in a competitive environment these risks are carried by the firm. Whilst the three events noted as being acceptable to constitute pass throughs the other three have a high degree for a firm to mitigate the impacts of the risk through proper management. It is therefore inappropriate for consumers to take a risk where TG has the ability (and responsibility) to take action to mitigate the risk through good management. The resources are made available to TG through the opex and capex allowances to institute this good management and thereby precluding the need to transfer the risk to consumers.

It is important to recognise that in a competitive environment, the ability to pass through costs to consumers is not possible, and firms have to absorb the costs (either through insurance or directly) of any exogenous impact. 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. TransGrid Depreciation

4.1 Early retirement of assets

TG 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 increased asset replacement program indicated by TG in its capex proposal. Equally, with the reduced loading on many of TG 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 TG 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 TG had ensured the assets lasted for the expected time.

In the reverse of this situation, TG 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 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 EMRF members and members of EMRF 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 longer than the average used to financially depreciate the assets in the building block approach. The application from TG supports this view in that TG has advised that some substations have continued to operate satisfactorily well beyond their assumed economic life[5]. 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 EMRF 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 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, relying more on time based approach supported by physical asset management approaches, such as condition monitoring. The EMRF 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 for a financial tool to address the commercial need for asset replacement.

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[5] For example TG provides the observations (page 71) that the Queanbeyan and Wallerawang substations were about 60 years old when they were replaced in 2010and 2014 respectively although elements had been replaced as needed over time. This compares life used for depreciation of 40 years used in table 10.1

The AER should require TG 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.

4.3 New and revised asset classes

TG has proposed the introduction of a new asset class based on a life extension program for towers. The EMRF does not have a problem in principle with introducing a new asset class for the life extension works carried out for the transmission line extensions. The EMRF accepts that the capital investment in the extension works is unlikely to have an engineering life as long as if the assets were replaced. However, this brings into question how the residual life of the primary assets is to be treated and TG provides no clarity on this.

The EMRF can see there are two options available:

1. The primary asset is depreciated as it is currently so that it would be fully depreciated at the end of the 50 years of operation. The life extension works would be separately depreciated over their 25 years.

2. The residual value of the primary assets would be added to the value of the life extension works and the total depreciated over the 25 years of life extension.

It is implied that TG has used option 1 but this is not made explicit. The approach actually implemented needs to be stated.

A second question also arises which could impact on the approach taken to depreciate the assets involved. In principle, the primary assets are depreciated over 50 years. This implies that they are used and useful for at least this period. The expectation of the life extension program is that this will extend the life of the assets by 25 years to 75 years. This indicates that the timing of the life extension program is critical and should be introduced at the time when the primary assets have reached their depreciated life. If the life extension program is introduced earlier than at the end of the primary asset life, there needs to be an assessment as to what point in the life of the primary assets should the life extension program commence. However, TG does not provide details as to when in the life of the primary assets the life extension program is being initiated.

TG also proposes to accelerate the depreciation of Secondary Systems from the previous 35 years to 15 years and Communications from 35 years to 10 years. Other than to refer to changing technology, TG provides no reason for such a massive change. The EMRF considers that such a large change in expected life in just 5 years is not warranted and unless greater explanation is provided to substantiate such a large change, the depreciation schedule should remain unchanged.

The AER has advised that it intends to use forecast depreciation as the basis of the roll forward model for the RAB. The EMRF 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. TransGrid Opex

In the Issues Paper the AER provided for the NSW distribution businesses, it makes the statement (page 49):

> "…additional investment may create need for more opex spending. This is because, in principle, a large asset base requires more maintenance than a small asset base."

The EMRF does not agree with this as the implicit view that a larger RAB automatically results in more opex is flawed, but it is an assumption that networks are keen to perpetuate. The only aspect where opex will automatically increase is where additional assets are added to the network through extension of the network.

The RAB can also increase for other reasons which do not cause an increase in opex in proportion to the RAB. These are:

- Replacement of existing assets with new assets of the same size. Replacement of a depreciated asset with new will increase the RAB. When this occurs the opex should fall as the cost of maintaining the replaced asset will no longer be needed and a new asset should require minimal maintenance.
- Replacement of an existing asset with a new but larger asset. This will augment the capacity of the network and will increase the RAB. However opex should either reduce or remain much the same as the replacing asset will be newer than the replaced asset requiring less opex). Further the increase in opex for a larger capacity asset does not increase in proportion to the asset value.

The EMRF considers that the assumption of increasing opex with the RAB is part of the reason for why there has been such a massive increase in network costs being passed onto consumers

The EMRF makes a general observation about the reasons TG seeks an increase in the opex allowance for period AA4. Many of the aspects of the TG application in relation to opex which TG uses to justify an increase in the opex are not based on changed conditions applying only to period AA4 and therefore are not step changes as such.

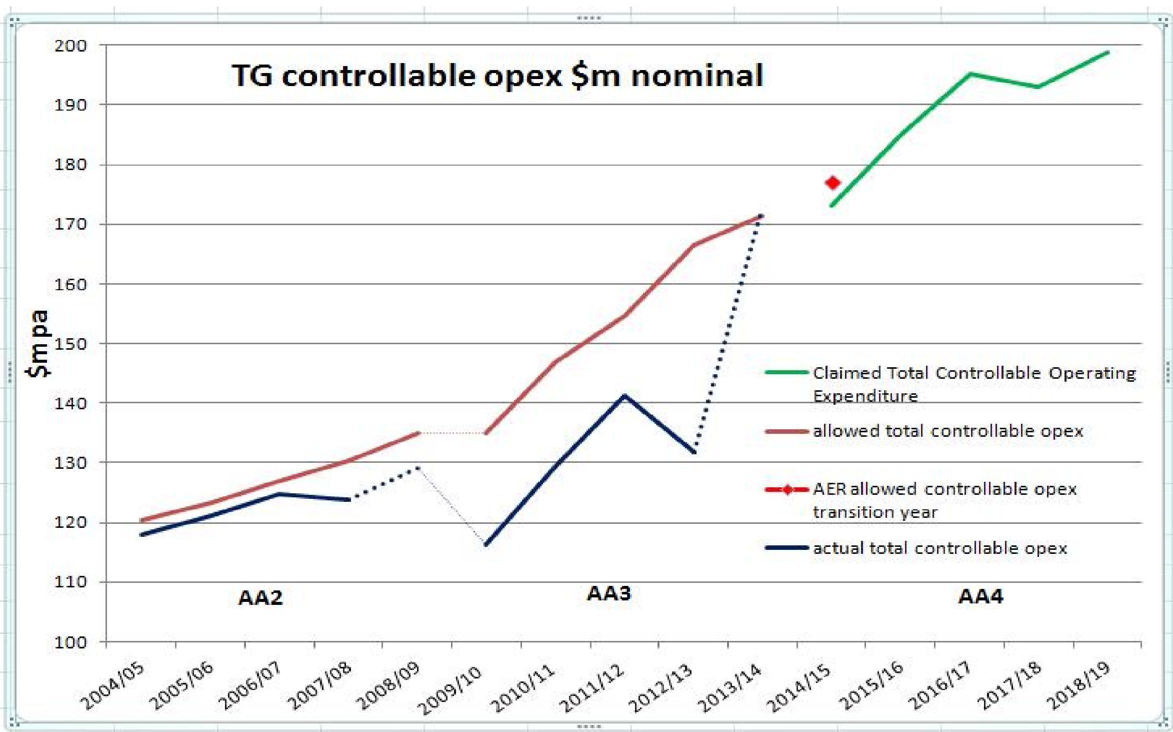
Specifically in section 6.3 (page 117) TG comments:

> "The first year's increase is primarily driven by enhanced consumer and community engagement, regulatory obligations arising from new guidelines issued by the AER and a more proactive approach to demand management innovation."

The EMRF considers that consumer engagement is an essential part of business and not a reason to increase costs to consumers; regulatory obligations have not increased but merely require the network to share information that is should already have available if it were operating efficiently.

TG than goes on to state that in subsequent years opex increases at 1.3% due to the effects of labour cost inflation and the need for major operating projects[6]. In fact the increase in the subsequent 4 years for controllable opex averages some 3.5% pa after a step increase in controllable opex of over 30% from the last full year of data - the base year 2012/13.

A view of the trend in controllable opex costs over time highlights that TG has consistently sought a massive increase in opex at each regulatory reset and then failed to use the opex granted.



Source: TG applications, AER decisions

[6] On page 166, TG asked whether consumers would accept an increase in operating costs roughly in line with inflation which is expected to be about 2.5% pa

The base year opex is identified as the opex in the last completed full year - in this case 2012/13. At a high level and using TG stated reasons for the increase in opex, the cost to consumers of implementing the TG consumer engagement program, complying with AER guidelines and demand management innovation costs of the order of $40m pa or a 30% step increase in costs. This is patently an overstatement of reality!

The efficiency benefit sharing scheme is intended to reward TG for operating at less than the allowed opex and on this basis the actual opex provides a sensible basis for setting opex into the future. Deeper investigation reveals that TG has not used the base-step-trend approach to forecasting future opex as is the basis of the guideline on forecasting allowances. However, TG has used a mish-mash of base year costs, maintenance rates from the 2012/13 year applied to new quantities and a zero base approach. This is a far cry from the intent of the AER guideline for setting forecast opex.

What the chart also shows is the "game" played by TG at the last two resets. The forecast costs for the final year of the regulatory period for AA2 is consistent with the AER allowance for the first year of the current period AA3. In fact, the actual opex for the first year of AA3 was significantly lower than that incurred in the base year of AA2, especially noting that the comparison is in $nominal and therefore include inflation. This same pattern is repeated between AA3 and AA4, where year 5 of AA3 is forecast to be a considerable increase from the base year and so influence the allowance for the first year of AA4.

The following table shows the direct comparisons of the base year actual costs compared to the average of the forecasts for each main category of controllable costs. Also shown is the percentage increase of the forecast over the base year costs.

$m pa nom	base year	average of forecast	% increase
Maintenance	60.7	77.62	28%
Major Operating Projects	2.8	9.52	240%
Maintenance Support and Asset Management	11.6	12.36	7%
System Operations	7.8	10.16	30%
Grid Planning	9.3	11.02	18%
Rates and Taxes	5	6.12	22%
Property	3.3	1.94	-41%
Health, Safety and Environment	1.8	4.06	126%
Information Technology	13	15.16	17%
Business Administration	11.9	13.16	11%
Corporate and Regulatory Management	4.5	27.9	520%
Total controllable opex	**131.7**	**189.02**	**44%**

Source: TG application

As the amounts shown are in $ nominal, to allow for inflation, an increase of about 10% would reflect maintenance of the of the base year costs. The table shows at a high level where the real increases in opex are being sought by TG. The EMRF addresses where those increases are considered to be excessive in section 5.2 below.

The EMRF also notes that the AER needs to address the ever increasing revenue reset costs as it is quite apparent that NSPs are spending excessively on consultant reports to justify increasing the revenue that they are allowed. It is concerning that consumers are providing more funds than ever to the NSPs so that NSPs can not only pay for these consultants but also cause consumers to pay increasing costs for the services provided that result from these consultant reports and views.

Overall, the EMRF considers that TG has sought a massive increase in opex that is not warranted.

5.1 Benchmarking and consumer engagement observations

TG provides a number of benchmarking observations to demonstrate that its opex is efficient. TG observes on page 144 that:

> "The benchmarks in … section [6.6] demonstrate the efficiency of TransGrid's operating expenditure and substantiate the use of actual costs in 2012/13 as the starting point for an efficient base year."

The EMRF has no better information that would counter this observation and expects that the Efficiency Benefit Sharing Scheme (EBSS) would have driven this outcome. The EMRF does not disagree that using the base year opex is probably a reasonable approach for setting the opex for the next period - what the EMRF does disagree with is the quantum added to the base year for the forecast period AA4.

TG does not attempt to show how its forecast opex costs are efficient. In fact, based on an average annual increase in opex of some 30% for the forecast period the EMRF would assume that the forecast opex is not efficient taking into consideration that there is falling growth in demand and consumption, so measures of load density and opex/energy transmitted would show a distinct reduction in opex efficiency even with a static opex allowance and increases in opex merely compound this trend.

TG provides a series of benchmark comparisons to the other four NEM TNSPs which show that TG opex is generally better than most of the others. The comparison that particularly galls the EMRF is the opex measured against RAB. This measure is so heavily influenced by the amount of capex used and the way the RAB was calculated in the early years that it has little meaning. In the case of TG where it has been accused of "gold plating" and over building, the measure of opex to RAB is of little merit. Indeed, it is the view of the EMRF that this measure is out of step with the current operating environment that it is rendered invalid for the purposes of this proposal.

TG has specifically reported on four specific questions that it raised with consumers in its engagement program, viz:

1. Maintaining a $3m pa increased spend on planning
2. Additional spending of $2m pa on demand side innovation
3. Additional spending of $2m pa on consumer engagement
4. Increase spending on opex in line with inflation

TG reports that all four proposals received considerable support. What is concerning is the manner in which these questions were posed as each was put in a way that the answer would be supportive. What was not expressed in the questions was what would be the actual outcome if the expenditure was not made.

The question on increasing spending in line with inflation particularly was misleading. When the question was posed, total opex was that in the base year and this was $143m. The expectation of those asked about increases in opex would be that the increases would be from this level - not the levels now sought by TG.

In other questions posed by TG in relation to the cost/reliability equation was that there might be a small reduction in reliability. This is misleading as TG is required to maintain at least N-1 reliability for its services and eliminating the costs sought by TG would more than likely result in no reduction in reliability, especially as TG is subject to a STPIS which incentivises increases in reliability.

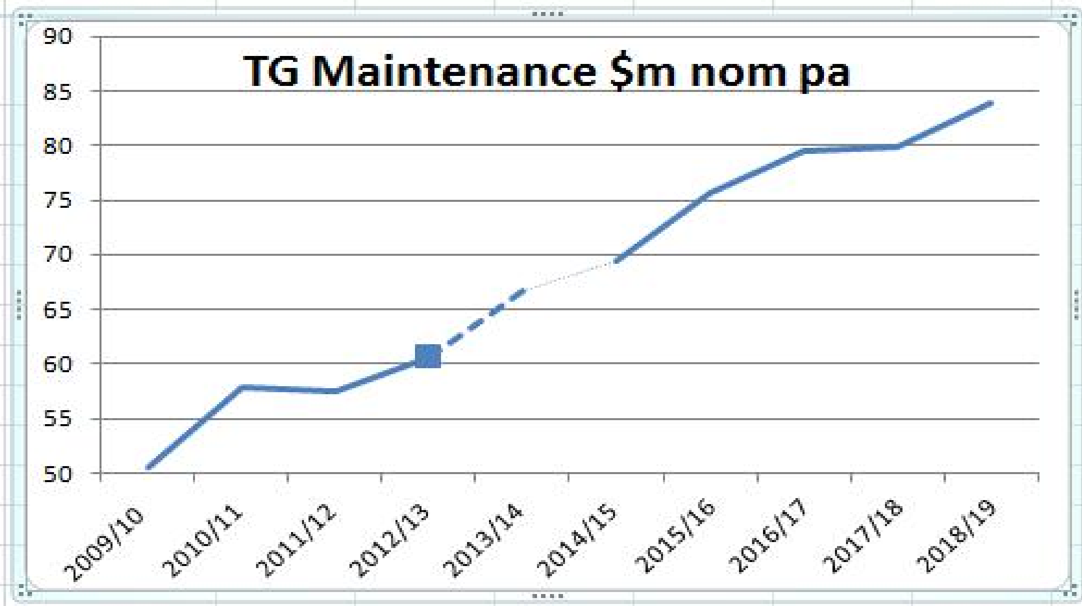
The EMRF does not consider that the apparent consumer support for the four categories of expenditure is valid due to the way the questions were posed. Indeed, due to the inherent bias and manner in which these questions were structured to elicit a desired response from their consumers, it is the view of the EMRF that they should not be used to justify any manner of price increase.

5.2 Detailed assessment of opex

For the charts used in this section, the base year opex is marked and the dotted line shows where TG has forecast opex for the following year.

5.2.1 Maintenance opex

TG seeks to increase its maintenance opex considerably form that incurred in the base year. The following chart shows the trend in maintenance opex.



Source: TG application

TG notes that its preventative maintenance program is adjusted for growth in the network and uses a formula based on forecast capex that, TG asserts, changes the size of the network. The EMRF has a concern with this approach as maintenance costs are more related to the number of assets than the cost of the assets. For example a substation which is increased in capacity by replacing a 50 MW transformer bay with a 70 MW transformer bay will have a similar maintenance cost even though the capacity has increased by 40%. Also assets that are replaced will increase the RAB as the new assets cost more than the depreciated assets replaced. Newer assets should require less opex than the assets that were replaced. So an increase in RAB can reduce opex rather than increase it as asserted by TG, especially when the major element of capex is for replacement as TG has forecast for AA4.

It does not seem that the approach used by TG reflects these realities.

TG comments that its condition based and corrective maintenance is effectively based on its network growth. This again does not reflect that corrective maintenance should reduce with the age of the network. The enhanced asset replacement program should lead to a reduced age of the network yet this has not been reflected in the costs of maintenance.

TG comments that it has used a base-step-trend approach to opex except where it considers a zero based approach will provide a more reasonable forecast than historical costs. It is this view that the new AER guideline on expenditure is supposed to address because consumers and the AER have seen large but unnecessary increases in opex being claimed based on zero based approaches to setting forecast opex.

The EMRF considers that the base-step-trend should be applied to all aspects of opex whereas TG appears to have used little of this approach in relation to its maintenance program cost. TG observes that the corrective maintenance allowance cannot be assed from historic work levels and must be assessed from the bottom up using rates and estimates of time commitment.

The EMRF disagrees. The implication of the TG comment is that the size of the corrective maintenance team would change dramatically over time, reflecting the amount of work identified to be carried out. In reality, a maintenance team (whether direct employees or contracted) needs to be kept stable as possible as this is more efficient than constantly changing team numbers and the TG comment that the corrective maintenance is set as a ratio to preventative maintenance supports the EMRF view. Corrective maintenance is scheduled from condition monitoring and allows the work to be scheduled - this is different to breakdown maintenance which cannot be readily scheduled.

TG observes that easement maintenance has been developed on a zero base approach because in the base year, TG had troubles with one of its contractors which resulted in some easement clearance not being carried out for some 8 months; TG then states that this work not done will be carried out in 2014/5 and 2015/16. The EMRF has difficulties in accepting the TG assertions other than the base year costs might be lower than might have been the case. If work scheduled for the base year was not done, then the work is unlikely to be rescheduled as late as TG assert as growth in the easement would have increased risks. The EMRF would expect that the uncompleted work would be rescheduled quickly to tie in with other easement maintenance and not have increased the forward workload significantly. If this essential work could be delayed by as much as TG asserts, then it would not have been essential to be carried out in 2012/13 and could have been deferred anyway.

Another aspect of the easement maintenance that needs to be recognised is that the work undertaken during the current period (AA3) was carried out under the much wetter weather conditions that applied[7]. The forecast for the next period (AA4) is that there is a greater likelihood of drier weather than a

[7] The AER has already had applications from other NSPs seeking additional allowances for easement management due to wetter conditions causing increased vegetation growth and these applications observed that the wetter conditions were more than forecast.

continuation of the wet weather experienced since 2010. This observation implies that the current actual costs include for a greater amount of vegetation clearance than is historically required and therefore using the base year costs could lead to an over allowance for this work.

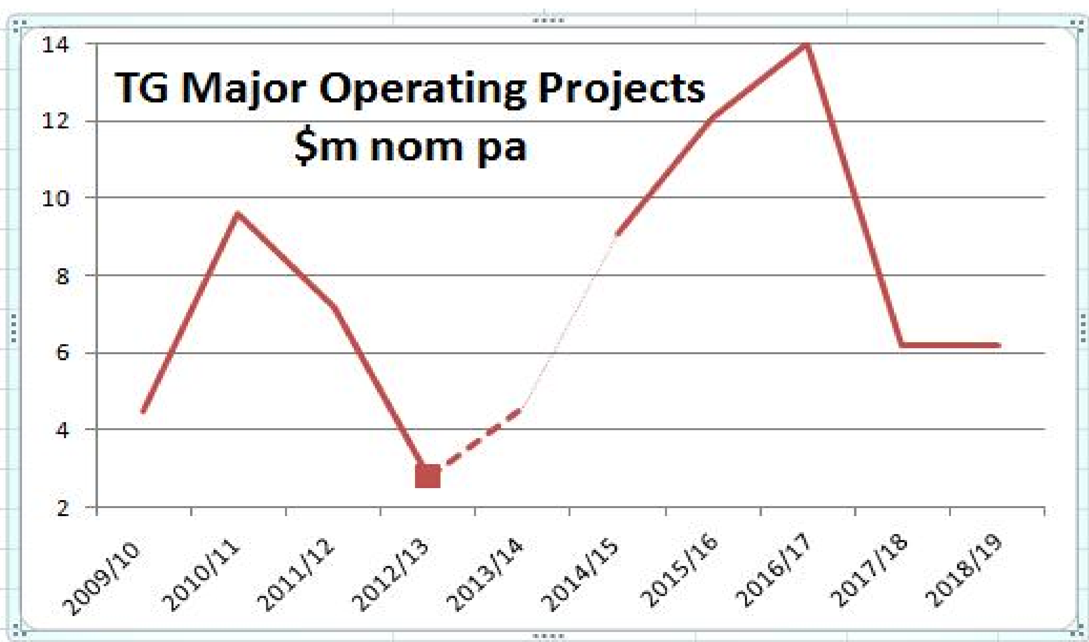
Overall the EMRF considers that the base year actual cost (perhaps adjusted for the $2m of work not carried out on easement maintenance should be used as the basis for setting the further allowance.

5.2.2 Major operating projects

The EMRF can understand why TG has certain elements of maintenance work carried out as discrete projects. However, the size of these projects is small and are consistent features of opex. The EMRF does not consider that these projects should be assessed on a zero base approach and can be readily assessed on a base-step-trend-basis.

This view is reinforced when TG details the "material major operating projects in table 6.5. The value of these projects is $18.6m which equates to about $3.7m pa.

The following chart shows the amounts TG claims for these projects compared to the historic costs



Source: TG application

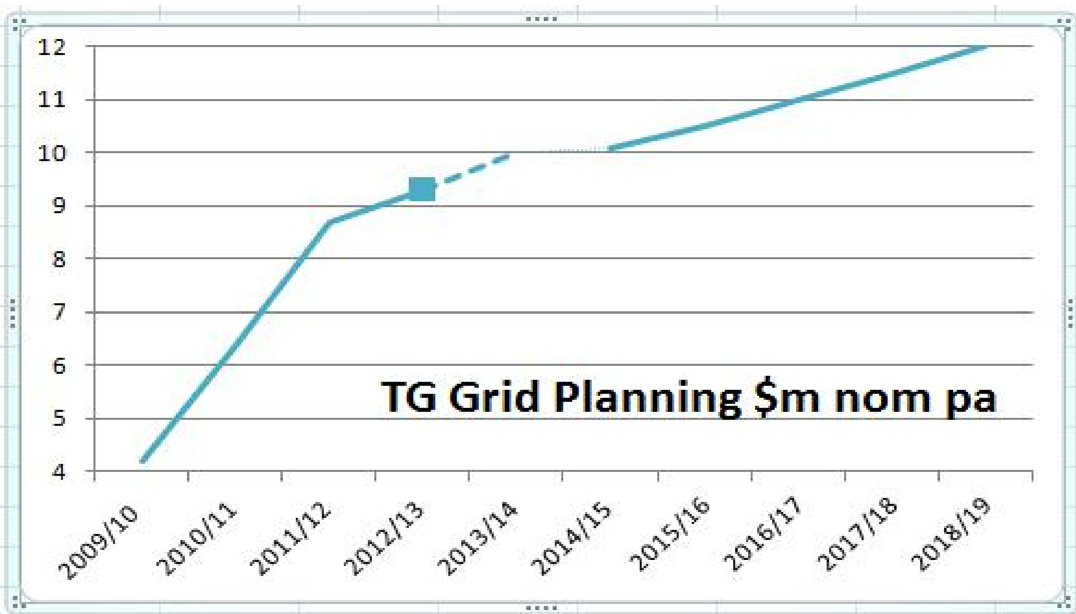
The average annual cost for this element of opex in the current period is $5.7m pa. TG seeks to nearly double this for AA4 to $$9.5m pa. TG has identified the five "material" projects to be undertaken and these total $3.7m pa. The EMRF queries where the other $6m pa will be spent as presumably the actual expenditure in AA3 included similar "material" projects.

The EMRF accepts that the base year did not include the effect of all the projects undertaken in AA3 (as the average for the period was higher than in the base year.

On this basis the EMRF considers that the claim for AA4 is too high by $4m pa

5.2.3 Grid planning

TG advises that it has increased its grid planning costs by some $3m pa and sought consumer support for this cost increase to be maintained. The following chart shows the trends in the cost element over time.



Source: TG application

TG shows that it increased its grid planning program from a base of $4m in 2009/10 to nearly $9m in 2011/12, an increase of $2.5m per year for two years.

TG asserts (on page 162) that this increase cost is "to better manage a large capital portfolio and improve responsiveness". The EMRF accepts that such practices are good practice but questions why TG is only introducing this program now when TG has been in operation for many years and has consistently stated that it is operating at best practice levels. TG should not be seeking additional funds for a program that has not shown a demonstrable benefit to consumers.

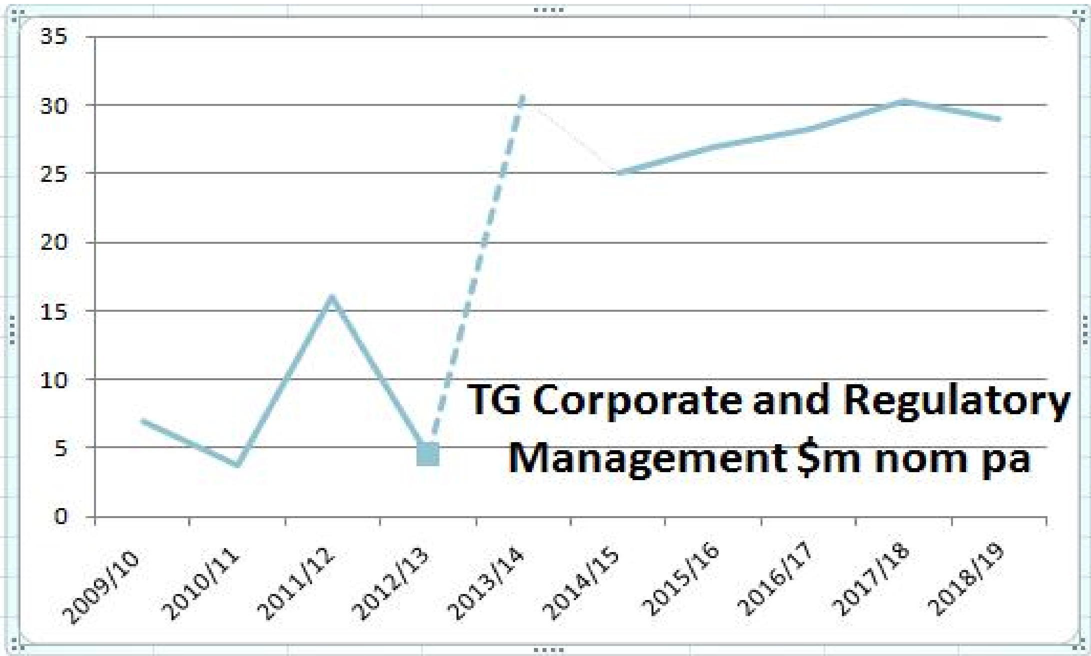
The EMRF would expect the see reduced costs in other areas or improved reliability as a result of such a program yet this does not seem to be the case. Firms in a competitive environment would introduce such practices in order to reduce the cost of its products. In contrast, TG has continually increased the cost of its products despite the addition of the new function.

The EMRF also questions whether this increased cost is a doubling up of other costs. For example, TG advises that this program "improves responsiveness" - but to whom? Is it to consumers? If so, then there would not be the need for additional funding for consumer engagement. The improved responsiveness does not appear to have significantly impacted loss of network availability, so the question is for what has the improved responsiveness been provided.

The EMRF does not consider that the increased costs are warranted or efficient based on the information provided by TG.

5.2.4 Corporate and regulatory management

In the base year the actual cost related to this element was \$5m and averaged about \$8m pa in AA3 excluding the forecast cost of \$30.6m to be incurred in 2013/14. The average cost for AA4 is expected to be about \$28m pa. The movements in the cost element are shown on the following chart



Source: TG application

The EMRF accepts that regulatory costs in 2013/14 would have increased as TG had to prepare a transition year proposal as well as a detailed regulatory proposal. TG also had to prepare a number of new reports for the AER as a result of the new guidelines. However, $30m for this work seems excessive, especially when comparing the corporate costs sought by Transend which is just as exposed to these costs as TG is. Transend shows their corporate costs **falling** not increasing when exposed to these additional requirements.

If TG is really incurring a regulatory cost increase of such a magnitude, then the EMRF queries whether the costs are reasonable, especially as consumers are expected to reimburse TG of these costs. The EMRF expects that the AER will carry out a review of the costs incurred for a regulatory review to ensure that TG is not overspending on this aspect of their activities. The EMRF notes that the extensive number of reports and consultant views regarding the arguments supporting an increase in WACC are excessive especially considering that there was a 12 month review period developing the AER guideline. The ENRF considers that TG should not be allowed to recover costs for carrying out work that is not in the long term interests of consumers.

The average of corporate and regulatory costs for AA3 was about $8m for the first four years of AA3 and if the exorbitant $30m for 2013/14 is included, then the average is $12m pa. Despite this, TG is seeking and average annual cost of $28m pa for this element of costs - more than doubling and already overstated cost incurred in AA3.

The EMRF considers that $12m pa overstates the efficient costs involved in this activity and considers that an amount below $10m pa would reflect efficiency.

5.2.5 Other elements

A review of the other elements of opex show that system operations shows a step increase of some $2m pa and health, safety and environment (HSE) a similar step increase above the base year.

The EMRF has trouble accepting these increases especially considering that there is a step increase in vegetation clearance included in maintenance for observed changes in safety requirements for this activity. The increase in system operations does not seem to be explained.

5.2.6 Declared step increases

TG provides a table (6.7) outlining the step changes it considers apply to period AA4

Table 6.7
New Obligations and Social Responsibilities ($m 2013/14)

Step Change and Driver	2014/15	2015/16	2016/17	2017/18	2018/19
Rental fees for communication towers on crown lands (IPART review of rental arrangements and fee schedules)	0.1	0.1	0.1	0.2	0.2
Ongoing requirements arising from the AER's new regulatory guidelines (New regulatory obligations)	0.6	0.6	0.6	0.6	0.6
Transfer of AEMO system operator functions (New regulatory obligations)	0.9	0.9	0.9	0.9	0.9
Easement maintenance (Catch up after response to safety obligations and cost escalation)	2.9	2.2	0.6	0.7	0.3
Consumer engagement program (New regulatory obligations and to meet changing consumer expectations)	2.3	2.2	2.1	2.2	2.2
Increase in demand management innovation allowance (Proactive approach to encouraging demand management)	1.1	2.3	3.3	3.6	2.6
Revenue reset (Regulatory obligation)	-0.1	0.5	0.9	0.1	-0.1

Source: TransGrid.

Of the claimed step changes, the EMRF agrees that some need to be accepted, such as those imposed by external agencies which are not in the base year costs (rental fees imposed by IPART, and imposition of the new regulatory guidelines by AER) and the AER must confirm the accuracy of the forecast costs.

The EMRF is not convinced that the transfer of AEMO functions is a legitimate increase in costs as TG comments that its contract with AEMO for AEMO to carry out this work has now completed. If AEMO used to carry out the functions for TG under contract, then the contract costs would be included in the base year and the claimed step change is not legitimate as it is still a task TG carries out either by contract or directly.

The EMRF notes that TG costs in the base year for vegetation clearance excluded some 8 months of work by its contractor and that this meant that some $2m of work was not completed. The table produced by TG above cites that some $6.7m is to "catch up" with the work not completed. This implies that the catch up for $2m of work not completed will cost consumers

$6.7m. This is totally unacceptable and as the EMRF comments above, the catch up work was either not required or would have been done in 2014/15 if it were urgent and needed to be done.

TG notes that there are increased HSE costs due to changes in the laws regarding vegetation clearance work. If so, then TG should cite the changes in the regulations, when they were enacted and justify the costs that are involved form any change. Unfortunately TG combines regulation changes with catch up work preventing any clarity on the costs involved.

There is a step change for consumer engagement but the EMRF queries the amounts claimed for the task and the value for consumers that this funding will achieve. In principle, the EMRF considers that TG should be able to readily accommodate the requirements of the consumer engagement guideline within the existing opex allowance. After all, this is what a firm operating in a competitive environment would be required to do.

The EMRF is concerned that TG sees that an increase in demand management innovation is required and the EMRF also queries what the benefits to consumers will be from this program. Unless there is a clear benefit to consumers from this cost, then it should not be allowed. Whether a benefit is likely can be assessed from the benefits to consumers achieved to date.

The claim for increased revenue reset activities does not reflect a step change as these costs are already in the base year. The EMRF notes that the AER needs to address the ever increasing revenue reset costs as it is quite apparent that TG is spending excessively on consultant reports to justify increasing the revenue that TG is allowed. It is concerning that consumers are providing more funds than ever to TG so that TG can not only pay for these consultants but also pay increasing costs for the services provided that result from these consultant reports and views.

5.2.7 Debt raising costs

In its historic costs for AA3, TG states that it incurred no costs for the raising of debt; this is true because TG is provided with its debt requirements from its owner the NSW government via NSW Treasury Corporation and therefore it incurs no costs for this activity.

Yet for AA4, it considers that it is entitled to an average of $8m pa to raise debt. To support its view, it goes to considerable effort to prove that this is a legitimate cost and employed a number of consultants (presumably an expense that consumers carry as part of the allowed regulatory costs) to argue that TG should be allowed a cost that they do not incur.

TG argues that the allowance historically allowed NSPs to acquire debt is too low and should be increased, yet this is not supported by TG actual costs (which are zero) but developed on a theoretical basis. The EMRF considers that the AER should require hard evidence that its approach to assessing the cost of debt acquisition really does result in a lower allowance historically provided.

The argument provided by TG and its consultants 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. TG 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.

5.3 Conclusions

The EMRF considers that TG has considerably overstated its opex needs for the next regulatory period by many tens of millions of dollars each year. TG has not used the revealed cost approach to the extent driven by the EBSS yet has benefited considerably through the EBSS by driving its opex costs down. The fact that TG has not accepted the revealed opex for all categories defeats the purpose of the EBSS.

Consumers are prepared to pay benefits under the EBSS but only when the revealed costs are used to the maximum extent to set the future cost allowances. TG has not used the revealed cost approach in many of the categories of costs and by doing so has effectively reduced the power of the incentive provided.

The EMRF is particularly concerned at the massive increases in the maintenance, major operating projects and corporate and regulatory claims, although some f the increases in other elements also do not reflect the benefits that the revealed cost approach provides for setting allowances

Overall, the EMRF considers that TG is still "playing the game" that it did in the 2008/09 revenue reset process to argue for increased allowances that cannot be justified. Whilst the benchmarking carried out by TG based on the base year costs seems to imply that TG is reasonably efficient. The lack of any benchmarking of the future allowances does not support the contentions that TG is operating at the efficient frontier.

5.4 AER questions

#	AER question	EMRF response
1	Are the opex proposals of each business justified? Please identify any specific areas you consider are not justified.	No. See comments above
2	What are your views about the cost drivers the businesses have identified?	TG has allowed for costs against each of the elements comprising opex but has overstated the amount required for each. In particular, the need for additional opex to account for growth has been overstated. TG has identified some step changes it considers increases the opex allowance, but has not explained why each of the step changes warrants increased opex. The EMRF has provided considerable assessment for each of the cost drivers and claims for increased opex in its detailed commentary above
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?	No. TG has only applied the revealed cost approach to a few elements of the opex and has used other approaches (eg zero base assessment and base year rates times increased quantities for other opex elements. Of particular note, TG has claimed significant debt raising costs even though it incurs no such costs. The EMRF 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?	No. See comments above In particular TG has used a flawed and limited consumer engagement process to provide support for a number of its less than warranted opex increases. The EMRF does not consider that the consumer engagement process used so far by TG provides any legitimate support for any of its opex claims. Further, the EMRF considers the timing of the

		consumer engagement would have had a marginal impact (if any) on the reasons for the opex increases due to the timing of the consumer engagement and the development of the application.

6. TransGrid Capex

The EMRF has assessed the capex programs proposed by TG in terms of its historical actual and allowed capex. The EMRF is well aware that it has neither the resources nor the data to examine each of the capex claims in terms of a "bottom up" assessment and relies on a "top down" assessment by comparing past performance with forecast needs.

The EMRF has been advised by its members (which all have very capital intensive operations) on how their managements review internal claims for capex. The EMRF members advise that capex programs proposed are ranked in terms of the benefit to the firm as the firm's ability to access capex is limited by a number of constraints that are greater than those experienced by the three DBs which are all government owned and access funds from government treasury corporations.

In this regard, the EMRF considers that the AER could well implement a similar scheme for assessing a reasonable capex limit to that used by firms subject to capital raising constraints. As a general observation, firms are limited in their ability to source capital for "business as usual" needs[8] from retained earnings and additional debt that does not change their gearing[9]. Using this approach as a guide, the AER could set a limit on capex that is considered to be reasonable and require networks to justify in quite considerable detail why they consider they have a need for more capex than this. In this way the AER could apply the top down controls used by firms subject to competition and are currently lackingin reguatory assessments.

TG capex for the NSW transmission system is presented in the following chart showing the actual capex in comparison to the forecast for the next period. The average actual capex for each period is also shown as is the ACCC/AER allowances for capex.

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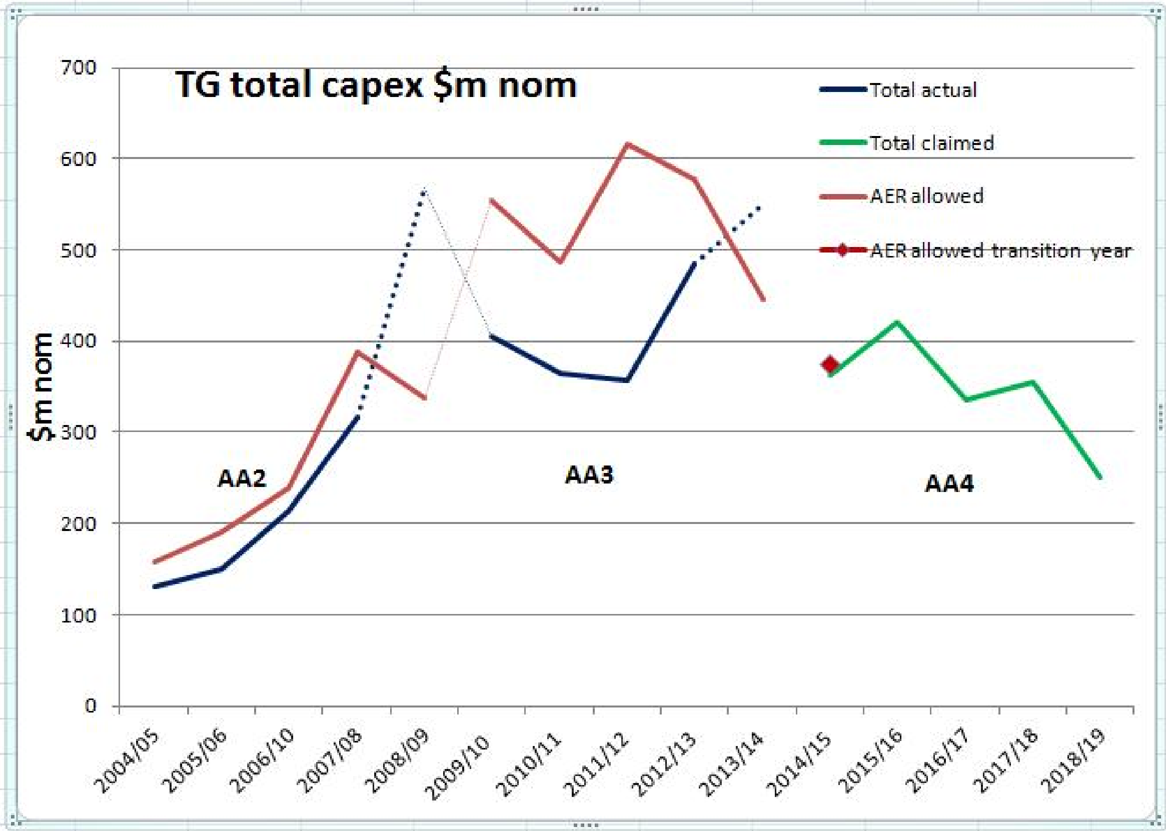
[8] The EMRF notes that for large acquisitions a firm may well go to the market to fund part of an acquisition but generally a firm does not seek additional equity for its business as usual capital needs

[9] The EMRF has noted that most electricity network firms have accessed more debt in recent years for capex such that their gearing (debt to equity) has significantly increased over time indicating that the the networks are not using the same constraints that firms in competition use



Source: Derived by EMRF from TG applications and AER decisions

This highlights that the proposed capex for period AA4 is quite excessive when seen in context with the capex incurred in periods AA2 and AA3 when it is recognised that the need for augmentation capex in AA4 is minimal. It also highlights that TG in periods AA2 and AA3 used considerably less capex than was allowed. It also shows that TG tended to expend capital later in each period than in the earlier years, minimizing the impact of capex overspends and by underspending early in each period, maximize the benefit of the overall underspend in each period.

What the chart also shows is that TG has under-run it's allowed capex considerably since 2002 by some $455m in net terms (even after allowing for the forecast overspends in AA2 and AA3), providing TG with a considerable financial benefit. In fact, the benefit that TG accrued from this under-run in capex during AA3 has been calculated by EMRF to be worth some $140m over the five year period. The detailed reasons for the capex under run have not been provided but TG has reported at other times that much of the under-run was due to the falling demand and a reducing need for network augmentation. It appears that the significant step increase in capex for AA3 compared to the capex used in AA2 was not really warranted.

TG advises that its capex for AA4 will be lower than in AA3. AA3 average annual capex was ~$440m pa whereas average capex for AA4 is about 20% less. The bulk of the reduction is due to a very much lower augmentation capex budget for AA4. At the same time, TG is seeking a massively increased replacement capex budget and a large increase in its security and compliance capex budget.

Whilst TG is forecasting a lower capex budget for AA4 than it actually incurred in AA3, it must be highlighted that TG has consistently under-run its budget allowances in AA2 and AA3. In AA4 TG will be exposed to a capex incentive scheme which will provide a further benefit to TG for under-running its allowance. This means that TG is incentivised to overstate its capex needs 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 are used as the basis for the future opex allowance. The EMRF accepts that the capex budget for augmentation might be a little more difficult to apply using a revealed cost outcome although, as the EMRF notes in the section on replacement capex, the revealed cost approach has much more applicability for replacement capex and this is the basis on which the EMRF has assessed the proposed TG replacement capex budget.

The EMRF 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 AA4 (as it did for AA3) significantly more capex than is required, the CESS will deliver considerably more benefits to TG than it achieved in AA3. 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, TG has used zero base approaches to setting the capex for AA4. The EMRF considers that the implementation of the CESS requires the similar use of historical performance to set the future allowances rather than allowing bottom up assessments to be used as the basis. This approach requires greater use of "top down" controls.

The EMRF notes that TG is also incentivsed to increase capex as there is a major difference between the WACC that the AER will allow under the rate of return guidelines and what TG actually incurs. The bulk of this difference lies with the cost of debt where TG is claiming a cost of debt at 200 bp (or more) above the cost it actually incurs. This provides an incentive for TG to use more capex than it actually requires to deliver the service.

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

6.2 Consumer engagement

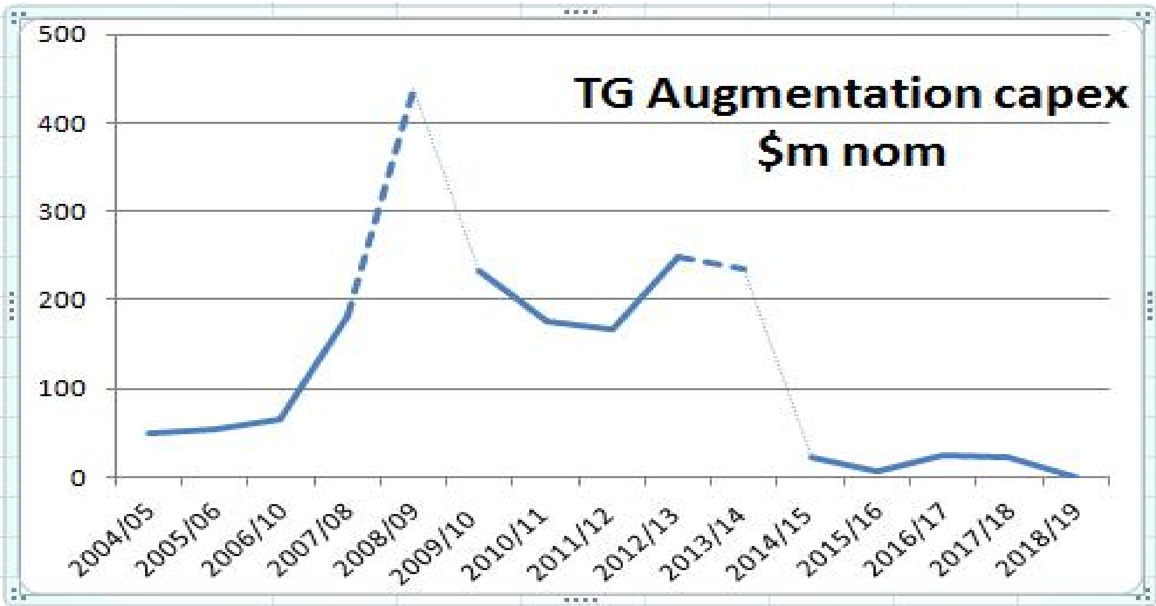
TG has provided views provided to it by consumers on the capex proposal and various specific elements of it (eg acquisition of land for future use). These consultations were from a number of relatively time limited roundtables and workshops. While the EMRF considers that these approaches to consumers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

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

Further, the EMRF notes that the timings of the consultations are such that the EMRF considers that TG 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.

6.3 Augmentation capex

Analysis of the TG augmentation capex in AA3 and its forecast for AA4 is revealing.



Source: TG applications

Examining the proposed augmentation capex for AA4 compared to that of AA3 shows that after spending considerably on augmentation in the latter stages of AA2 and during AA3 due to the expectation of continued growth in demand, TG has accepted that demand in NSW is forecast to remain below the peak experienced in 2010/11 until the early 2020s under all of the AEMO scenarios. On this basis, there would be the expectation that no augmentation capex would be needed during AA4.

In fact, TG has forecast a need of some $77m in AA4 for augmentation capex and has provided details for augmentation for two reinforcement projects (Gunnedah/Narrabri/Moree and Beryl area) totaling $17m. The EMRF does not have sufficient knowledge of the intricacies of the changes in demand at these sites to make informed comment but does expect that the AER will institute a careful analysis to ensure there is a need, despite there being no expected growth in state wide demand. Further, TG has advised of a requirement of the ACT government that it requires an additional feeder to the region at a cost of $31.4m.

These three projects only justify 60% of the augmentation capex sought. Justification of the other 40% of the augmentation capex should be assessed by the AER considering that there is no growth forecast in NSW demand for AA4

The EMRF is also concerned about the augmentation project for the ACT. The EMRF accepts that the ACT government has the right to request augmentation of its supply but the EMRF questions whether all consumers in NSW should be required to pay for the augmentation. As ACT is a separate user entity then the EMRF considers that this project should be considered to be a new connection and therefore the costs of the augmentation should be borne by the user requesting the additional connection. Whilst the augmentation project capex does constitute capex under the allowed budget, TG should be registering the costs as a customer contribution as applies for other users seeking a connection. Alternatively, TG could exclude this project from the capex budget and require ACT to pay for the augmentation as a negotiated connection. Either way, NSW consumers should not be required to pay for all or even part of the additional connection as they derive no benefit from it.

6.2 Replacement capex

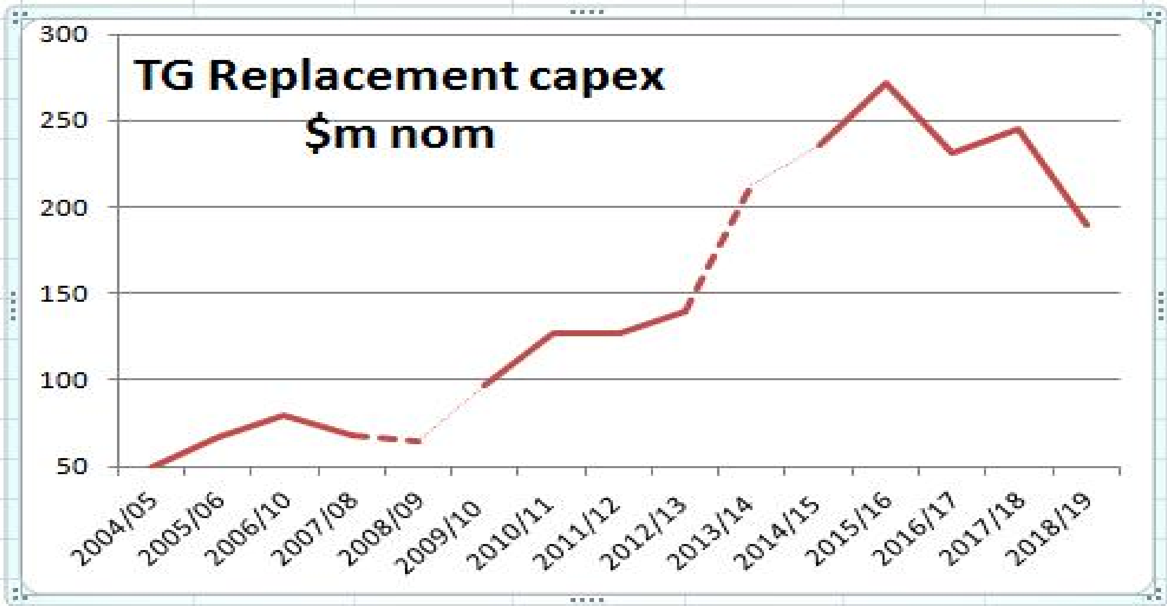
The EMRF is aware that there is an incentive on a network to replace an asset that is fully depreciated as fully depreciated assets do not provide any revenue under the building block approach to setting revenues.

So, even when an asset is still used and useful, there is an incentive to replace it when fully depreciated. This issue is particularly important when consumption is falling. A lightly loaded asset is likely to have a longer useful life than an asset that is heavily loaded and therefore still be used and useful after its theoretical economic life is passed.

The EMRF strongly recommends that the AER address this issue in its assessment of the allowance for replacement capex.

In previous years, replacement capex was the second largest capex element, well behind augmentation capex. In this application, TG 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 has risen from about $80m pa ($'13/14) in AA2 to $130m pa ($'13/14) in AA3 excluding the very high forecast for the final year of AA3. TG is forecasting a further increase in AA4 to $235 pa.



Source: TG applications

The EMRF has insufficient detail on which to provide a detailed analysis of each project proposed but recognizes that such projects are developed on a "bottom up" approach based on assessment of need. As a general observation, the EMRF considers that renewal/replacement projects can be assessed on a revealed cost approach rather than on a bottom up basis. This is because renewal 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 EMRF 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.

In its application for replacement capex in AA3, TG forecast that it would require about $110m pa (($'13/14) for replacement capex. In fact it used about $130m pa for the first four years of AA3. In the application for AA2, TG forecast that replacement capex would be $50m pa ($'13/14) and TG used about $80m pa ($'13/14). That TG overspent its replacement capex budgets in AA2 and AA3 is understandable as TG had commenced a condition monitoring regime as part of its asset management program in AA1 and this was expected to provide a much better indication of what might be required in the following decade which covered periods AA2 and AA3. By the end of a decade it was expected that TG would have "caught up" with all of the outstanding replacements needed to maintain the network. This means that the actual replacement capex for AA3 would provide a good indication of replacement capex in the future.

The trend of capex movements in AA3 shows that the replacement capex in the base year is consistent with the replacement capex in the previous two years, supporting a view that the base year replacement capex could be used to forecast replacement capex needs in the future. On this basis, an indication of efficient replacement capex for AA4 would be of the order of $150-160 m pa rather than the $235m pa sought by TG.

TG provides more detail in tables 5.2, 5.3, 5.4 and 5.5 of the proposed replacement capex[10] for each of the five replacement classes - substation renewal, secondary system renewal, transmission line life extension, underground cable remediation and communications upgrades and replacements. Only allowing for specifically identified projects to be carried out up to 2019 (the end of AA4) and for underground cable remediation, the total of works proposed is $700m or $140m pa. The value of works proposed in the tables post 2019 adds a further $45m pa. Overall TG seeks $235m pa for replacement capex for AA4.

This information can be tabulated as shown below

Replacement capex $m ('13/14) per annum	**claimed**	**actual**
TG AA2	$50m	$80m
TG AA3	$110m	$130m
TG AA4 projects tables 5.2-5.5 up to 2019 plus U/G cable	$140m	
TG AA4 projects tables 5.2-5.5 post 2019	$45m	
Other TG replacement capex not detailed for AA4	$50m	
Total TG replacement capex for AA4	$235m	

Source: TG applications, AER FDs

This implies that the replacement capex needed by TG for AA4 is likely to be about $140-$150 rather than the $235m pa sought by TG.

TG does provide a view that its capex program would result in the average age of the network assets remaining at about 27-28 years. This is shown in figures 5.5 and 5.6 and this would support a view that the overall capex is appropriate.

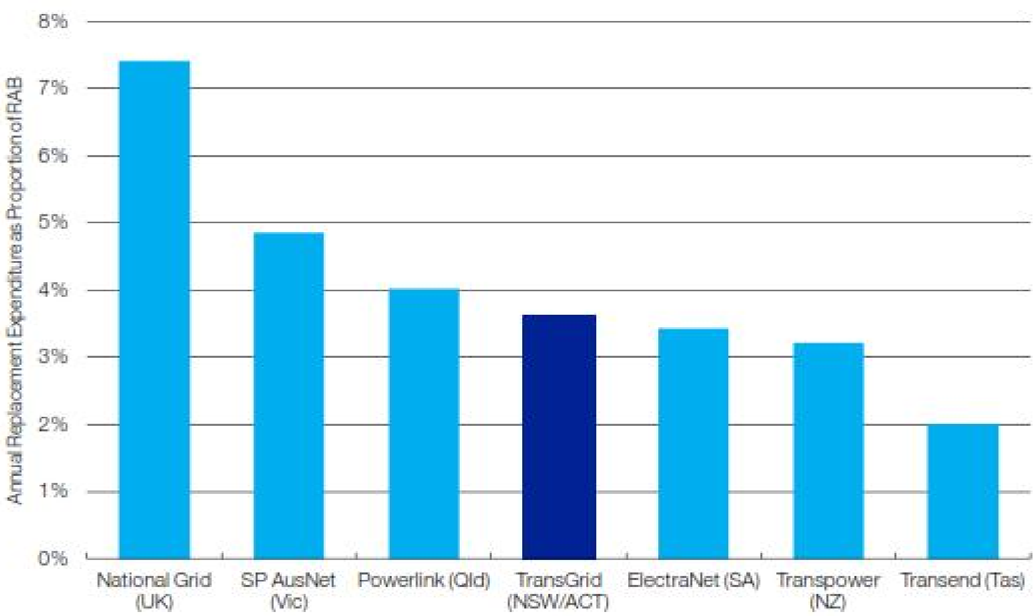
The EMRF does not agree with this entirely as the amount of electricity carried by TG assets has fallen considerably in recent years by 13% since it peaked 2008/09 and the June 2014 AEMO NEFR indicates that the volume of transfer is unlikely to increase markedly in the short term. The EMRF comments that the stress on the

[10] The EMRF does not have sufficient information to be able to assess whether these projects are all necessary and has accepted them at face value. The AER should require investigation to identify if the projects are all warranted.

assets is much reduced by this much reduced energy flow and this will result in assets having a longer life than those where the assets are more heavily stressed. So whilst a reduced capex in AA4 might result in a slightly increased average age, the expectation is the assets would have a longer life than would be otherwise expected and therefore not impose unnecessary costs on consumers by increasing capex merely to hold the average age at the current level.

TG provides a figure 5.3 which benchmarks replacement capex as a proportion of RAB between the NEM TNSPs, New Zealand's Transpower and UK's National Grid.

Figure 5.3
Replacement Expenditure as Proportion of Regulatory Asset Base



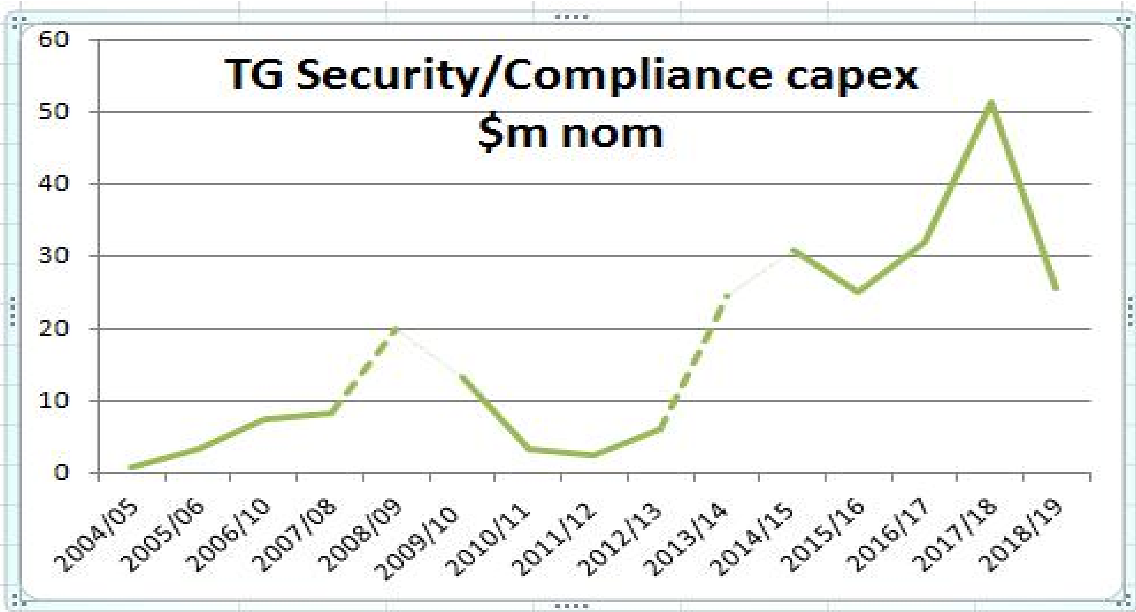
Source: TransGrid. Comparison is based on average annual forecast replacement capital expenditure in the most recent revenue determination or proposal, as a proportion of opening regulatory asset base.

What is important about this benchmarking study is that TG is in the mid point or other comparable TNSPs for its replacement capex in AA3. An increase in replacement capex as proposed by TG would dramatically change the status of TG in this benchmarking comparison.

6.3 Security/compliance capex

TG observes that it now has the tools available for it to more readily and more accurately measure transmission line clearances than in previous times. As a result, TG comments that some power lines do not meet design clearances and therefore need to be rectified.

TG provides information on the historic cost of security and compliance capex along with the forecast capex. This is shown in the following chart.



Source: TG applications

This shows that TG has historically needed about $9m pa to meet security and compliance needs but in AA4 is seeking about $33m pa - an increase of nearly four times. The EMRF considers this is excessive.

TG comments that the increase is driven because they now know that line clearance in some areas are less than as designed. Equally, the EMRF notes that these less than designed clearances have not resulted in harm and may well reflect acceptable practice or even that the design clearances are excessively conservative. That there has not been a major impact on TG performance or safety issues in the past due to the less than designed clearances indicates that the current levels are acceptable (even if they do not comply with design clearances[11]) and the only reason that the clearances is now an issue is because of the ability to measure to see that there is a problem.

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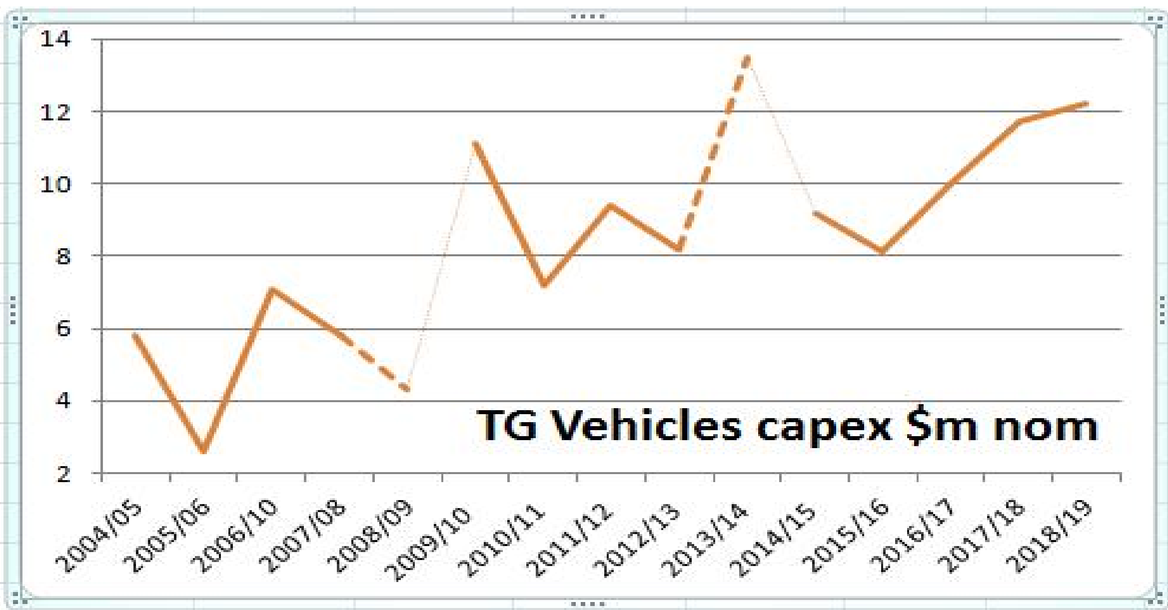
[11] TG makes no observation as to the extent that the clearances do not meet design criteria and for how long these clearances have not complied. The EMRF notes that clearances might not comply by a small margin and have been non compliant for many years. This would result in a low probability future failure. With this in mind, TG needs to provide considerably more support for its contention that rectification work must be carried out.

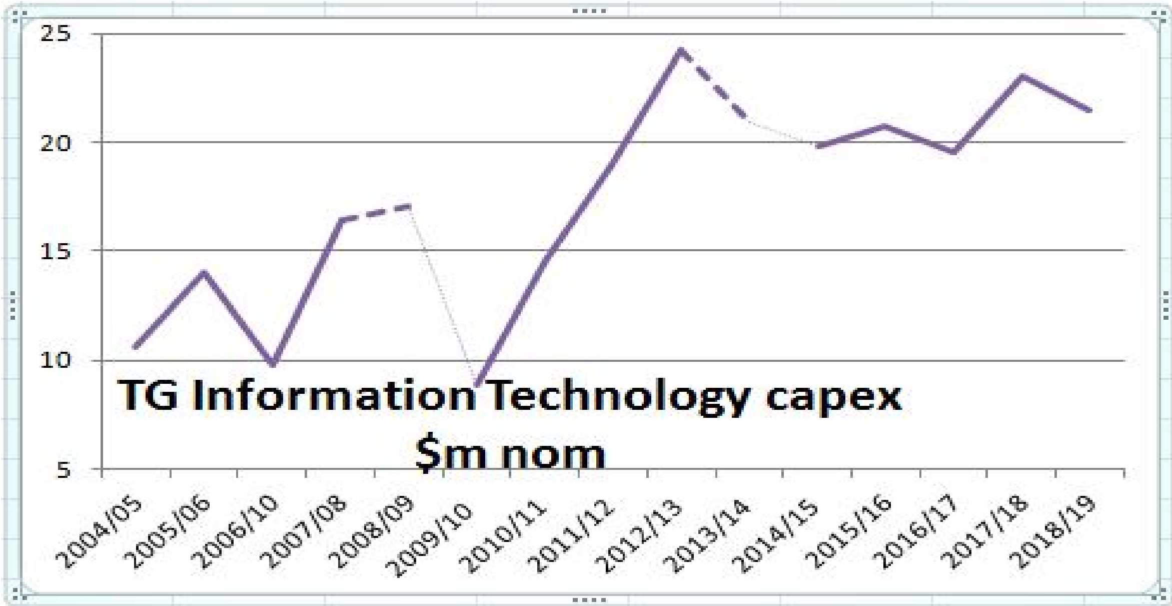
The EMRF considers that there will be some parts of the network where the clearances might constitute an unacceptable risk and should be rectified first in the areas where such a risk might have considerable impact on overall safety. The EMRF considers that the program could continue at the same level as in the past with a focus on those areas of greatest risk rather than carrying out a massive capex program to rectify every area where clearances are less than designed.

6.4 Other capex

The EMRF has reviewed the other capex elements at a high level and consider that generally, subject to deeper AER analysis, that the capex claims are reasonably consistent with past capex in those categories although some do show an upward trend above the long term allowances such as in the case of the vehicle acquisition and IT. These deserve a closer look by the AER



Source: TG applications



Source: TG applications

TG especially comments on the acquisition of land for future use and provides views from consumers who attended the workshops and roundtables. The EMRF considers that sensible land acquisition now for future use has considerable value. Equally, the EMRF also considers that acquisition should only occur if there is a high likelihood of the future need of the land.

The EMRF points to the falling demand and reducing consumption of electricity from the grid. This implies that the need for future augmentation will be modest over the next decade. This then raises the question as to how long out should current consumers pay for an asset that is not going to be used for many years by future consumers. The National Electricity Objective (NEO) is written in terms of the long term interest of consumers but provides no guidance on what constitutes "long term". The EMRF considers that in terms of acquiring land, a decade of no use of the asset is at the high end of reasonable. On this basis, the EMRF considers that if the land does not have a high likelihood being used within a decade, then it should not be acquired by TG.

The EMRF also notes that one element of land acquisition relates to the augmentation of the ACT supply lines. As noted above, the EMRF does not consider NSW consumers should fund a connection that is to be used by a specific end user. If the land is required to deliver power to the ACT, then that land should be acquired by the ACT government, not by NSW electricity consumers.

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, TG proposes to increase its opex from current levels as well as increase its replacement capex.

Where there is growth in a network there is an expectation that there would be additional opex attributable for new capex, 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 TG application is concerned and ensure that the opex reflects the introduction of new assets for old.

In this regard the EMRF 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 EMRF considers that, even though capex for AA4 is forecast to be less than that in AA3, TG has still made an ambit claim for capex and that detailed evaluation indicates that the capex claimed is severely overstated in most areas.

In particular, the EMRF considers that TG 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	EMRF response
1	Are the reasons for the capex proposals of each business well supported by their revenue proposals and/or consumer	No. See comments above. Whilst the need for some of the capex is explained, TG does not provide details for a significant amount of capex.

	engagement activities?	Even where it provides some support for the planned capex, the details do not support the extent of the capex claimed. Further, while TG 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 EMRF 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.

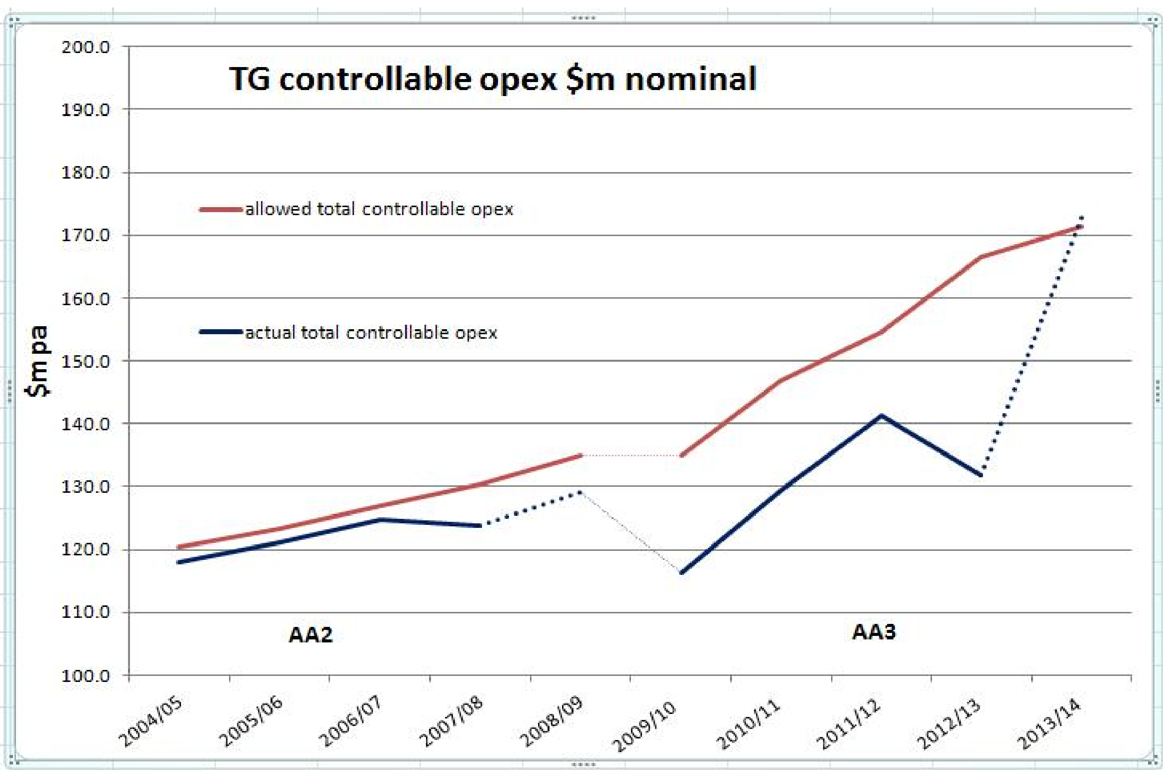
7. TransGrid Efficiency gain

The EMRF is totally supportive of an opex incentive scheme to encourage regulated businesses to reduce their costs. The benefit of this is that TG can reduce the costs of providing the service, and by sharing the savings with TG, consumers will be better off in the long term. However, in this proposal TG has not applied the principles underpinning the incentive scheme, choosing to limit the amount of the opex that is set using the revealed cost approach.

There are two caveats to this in-principle support

1. The savings should be the outcome of actions by TG and not just because TG was able to convince the regulator at the last reset to give a comfortable allowance, and
2. The savings achieved will continue to be shared for a period into the future.

TG 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 the last four years of the last two periods (AA2 and AA3). The following chart is the same as that developed for section 5 above.



Source: TG applications, AER decisions

TG identifies that they have never over-run the allowable opex in either period AA2 or AA3 but has improved their performance over time. This consistent under-running of opex 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 TG has been able to convince the regulator of the need for higher allowances for opex, allowing TG to earn both the immediate benefit of opex under run but an additional benefit into the next period

The fact that the actual opex has seldom approached the allowed level gives rise to a very real concern that the bulk of the opex under run since 2004 has been the result of regulator “gaming” rather than TG causing real savings from their own actions.

The EMRF does not support providing TG 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 TG substantiating that savings really have been achieved by direct operational actions of TG. TG 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 EMRF is sceptical as to its validity as an “earned” underrun as distinct to a “gamed” under run. With this in mind, the EMRF considers there is no justification for any carry over into the next period.

8. Service standards

TG 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.

TG consultant Parsons Brinckerhoff (PB) was engaged to generate the previous performance of TG under the new STPIS criteria and produced the following table.

Table 1.1 Reliability Data 2009-2013

Parameter	2013	2012	2011	2010	2009
Lines outage rate – fault	18.36%	16.65%	16.06%	15.71%	22.51%
Transformers outage rate – fault	18.14%	16.38%	9.67%	16.76%	13.66%
Reactive plant outage rate – fault	9.90%	15.71%	18.27%	12.77%	21.05%
Lines outage rate - forced outage	21.34%	8.07%	6.21%	17.80%	21.47%
Transformers outage rate - forced outage	23.64%	20.33%	20.47%	21.97%	14.84%
Reactive plant outage rate - forced outage	24.38%	13.47%	17.51%	29.29%	17.29%
No. of events >0.05 system minutes	4	3	3	3	3
No. of events >0.25 system minutes	0	1	0	1	1
Average outage duration	180.32	94.23	137.11	225.83	84.96

The EMRF has no ability to assess whether this outcome is correct and considers the AER has a responsibility to ensure that the outcomes are correct. Further, the STPIS has a number of exclusions relating to allowed outages and the performance measures calculated by PB should be assessed against the allowed exclusions.

From this data, PB proposed (and TG accepted) that the targets should be the arithmetic average of the historical performance (as in the version 4 scheme) and that the caps and collars be set using 2 x standard deviation (2SD).

Table 3.3 Parameter values

Parameter	Collar	Target	Cap	Weighting
lines outage rate - fault	22.46%	17.86%	13.26%	0.20
transformer outage rate - fault	20.26%	14.92%	9.58%	0.20
reactive plant outage rate - fault	23.32%	15.54%	7.76%	0.10
lines outage rate - forced outage	30.48%	14.98%	0%	0.00
transformer outage rate - forced outage	25.51%	20.25%	14.99%	0.00
reactive plant outage rate - forced outage	33.57%	20.39%	7.21%	0.00
loss of supply event frequency (Events > 0.05 system minutes)	5	3	1	0.15
loss of supply event frequency (Events > 0.25 system minutes)	3	1	0	0.15
average outage duration	284.25	144.49	4.73	0.20

Using this, all but two of the past performance outcomes would lie within the bounds of the cap/collar ranges. The EMRF questions whether a 2 x SD is appropriate for setting caps and collars and that perhaps a smaller multiple of SD, such as 1.5xSD might be more appropriate to set the caps and collars.

However, the STPIS recognises that the outturn service performance will be heavily influenced by the amount of opex and capex involved. In this application, TG proposes to massively increase its replacement capex and increase its opex. Both of 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 if the revealed cost approach to set efficient allowances. As TG has claimed increases in opex and replacement capex above the historical levels, the EMRF is concerned that the service standards derived for AA4 are consistent with the other schemes.

In particular, the historic service performance was based on about half the amount of replacement capex used in the five year period from which the targets have been developed compared to the amount 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, TG will also achieve better service performance for the NCIPAP process, further indicating that the service targets will be more than achieved. TransGrid comments in section 5.5.3, page 90:

> "The forecast capital expenditure in this proposal does not include expenditure to improve performance under the Service Target Performance Incentive Scheme or for projects included in the NCIPAP."

yet increasing replacement capex must have an impact on service standards.

The EMRF 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 TG could "earn" a STPIS bonus. Certainly an outcome such as this would not be efficient or in the long term interests of consumers.

9. TransGrid NCIPAP

TransGrid has provided a table (appendix AG, table 3.1) summarising the cost of 28 projects that it considers should be included in its proposed Network Capability Incentive Parameter Action Plan (NCIPAP). The total cost of these projects is $36.3m which is to be added to the allowed revenue for the regulatory period. Excluding the research project on storage which has no definable financial benefit, the average payback for the other 27 projects is about 6.2 years based on the benefits calculated by TransGrid[12].

As a general observation it would appear that, because the projects nominated by TG have not been carried out as part of the normal capex approach in the past, a six year average payback is not considered to be prudent.

As the MEU understands the NCIPAP, an allowance of 1.5% of revenue is a cap to include a number of small projects that could be undertaken which would 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 by any project 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 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.

The most common approach used by firms in the competitive sector is to assess small discretionary projects such as these on a simple pay back method – that the benefits of a project had to be recovered by savings made in 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 although TransGrid has assessed the paybacks for the projects nominated). 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

[12] There are three projects valued at $7.8m which TG estimates have a payback of more than 13 years and one with a payback as long as 18 years. The EMRF finds it impossible to see how these projects could be assessed as worthy.

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) have been 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. TransGrid has nominated 28 projects for the NCIPAP yet TransGrid only asserts that it has collaborated with AEMO with AEMO staff involved in discussions to identify operating conditions. Whilst AEMO has presumably endorsed all of the projects, this is not clear.

The MEU has a number of concerns with the project approach used by TransGrid

- A more detailed review of each project proposed shows that many perhaps should have been addressed within the existing regulation and not waited to the NCIPAP. It would appear that TransGrid is using the NCIPAP process to gain a reward for doing what it should have already implemented.

- Each of the projects has been assigned a ranking yet the ranking bears no relation to the benefit to consumers in terms of payback. For example, the fastest payback assessed is 1 month for installing capacitor banks at Beryl, yet this project is assigned a ranking of 14. In contrast, the project (Dynamic Line Ratings & Transmission Line Uprating 4 & 5 Yass – Marulan, 9 Yass – Canberra, 61 Yass – Bannaby & 39 Bannaby –Sydney West 330kV Lines) with a payback of 15 years is ranked 13, ahead of 5 projects with a payback of less than 2 years

  TG advises that it and AEMO have ranked projects so that improvement in network capability under normal contingency events is ranked higher than projects which provide a benefit under multiple contingencies; projects which increase network capability but have multiple benefits are ranked in proportion to the amount of benefit deriving from improved network capability. Other projects are ranked below these regardless of the benefit to consumers.

  The EMRF does not agree with this approach. If the network capability improvement is required then it should be included in the normal capex program and not in the NCIPAP. The NCIPAP is intended to deliver benefits to consumers and not be prioritized as TG and AEMO have.

- A detailed review of the projects indicates that only 12 would deliver a payback in two years or less and these would cost consumers $8.5m. This is shown in the following table

Category	Project	Estimated Cost	TransGrid assigned Rank	TransGrid assessed payback
Dynamic Line Ratings & Transmission Line Uprating	969 Tamworth 330 – Gunnedah 132kV Line	$300,000	14	0.1
Capacitor Banks	Beryl Capacitor Bank	$1,900,000	16	0.5
Current Transformer Secondary Ratios	Queensland – New South Wales Interconnector	$55,000	1	0.5
Terminal Equipment	81&82 Liddell Newcastle & Tomago lines	$600,000	15	0.5
Terminal Equipment	67 & 68 Murray – Dederang Switchbays	$360,000	2	0.75
Protection & Metering Upgrades	993 Line Protection & Metering Upgrade	$90,000	3	1
Dynamic Line Ratings & Transmission Line Uprating	Snowy Lines	$2,211,000	17	1.25
Dynamic Line Ratings & Transmission Line Uprating	83 Liddell – Muswellbrook, 84 Liddell – Tamworth 330, 85 & 86 Tamworth 330 – Armidale & 88 Muswellbrook – Tamworth 330 330kV Lines	$1,100,000	4	1.5
Protection & Metering Upgrades	99P Line Protection & Metering Upgrade	$50,000	5	1.5
Travelling Wave Fault	North Western 132kV System	$877,000	18	2
Control schemes	Extension of Directlink Tripping Scheme	$600,000	7	2
Dynamic Line Ratings & Transmission Line Uprating	65 and 66 lines Murray Tumut	$400,000	6	2
Total cost		**$8,543,000**		**1.2**

The MEU considers these projects only should be included in the NCIPAP once the benefits have been confirmed.

- Of the 28 projects, 11 (ranked 1, 2, 4, 6, 7, 9, 10, 11, 12, 13 and 15) deliver their benefit in terms of market impact. TransGrid has a market impact incentive scheme already in place yet none of these projects delivered sufficient benefit to consumers to provide TransGrid with the incentive to undertake the projects without the introduction of the NCIPAP. This is an issue that the AER needs to investigate

- The 6 travelling wave fault location projects (ranked 17, 18, 19, 20, 24 and 25) have the bulk of the benefit based on fire detection benefits valued at $291.3m coupled with a 10% likelihood which seems very high. Yet no explanation is provided as to what the $291.3m value is, where it is derived from, how the likelihood was assessed and how "firm" the benefit derived is. In the absence of this "benefit" the projects are not viable.

- 2 projects (ranked 14 and 16) derive their benefit from deferral of capex. The MEU would have assumed that such projects would have been implemented under the normal course of capex works.

- 2 projects (ranked 3 and 5) derive their benefit from avoiding the potential for load shedding or loss of supply. Such projects would normally be in the capex claim under reliability, yet obviously have not been addressed earlier.

The MEU is concerned that the anticipated benefits claimed for the projects have been 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 the capital involved will be added to the RAB and consumers will pay for the capital for many years to come.

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.

TransGrid provides a clear indication that the NCIPAP capex and opex will not be integrated into the allowed revenue as stated in Appendix AG section 2.5:

> "The cost of the projects proposed in this plan will not be included in capital or operating expenditure in TransGrid's revenue proposal."

On this basis, the assumption made by the EMRF is that the capex (and opex) used for the NCIPAP will not be included in the RAB, although the EMRF is of the view that NCIPAP projects do get rolled into the RAB at the next revenue reset review. The EMRF considers the AER must ensure that this does not occur.

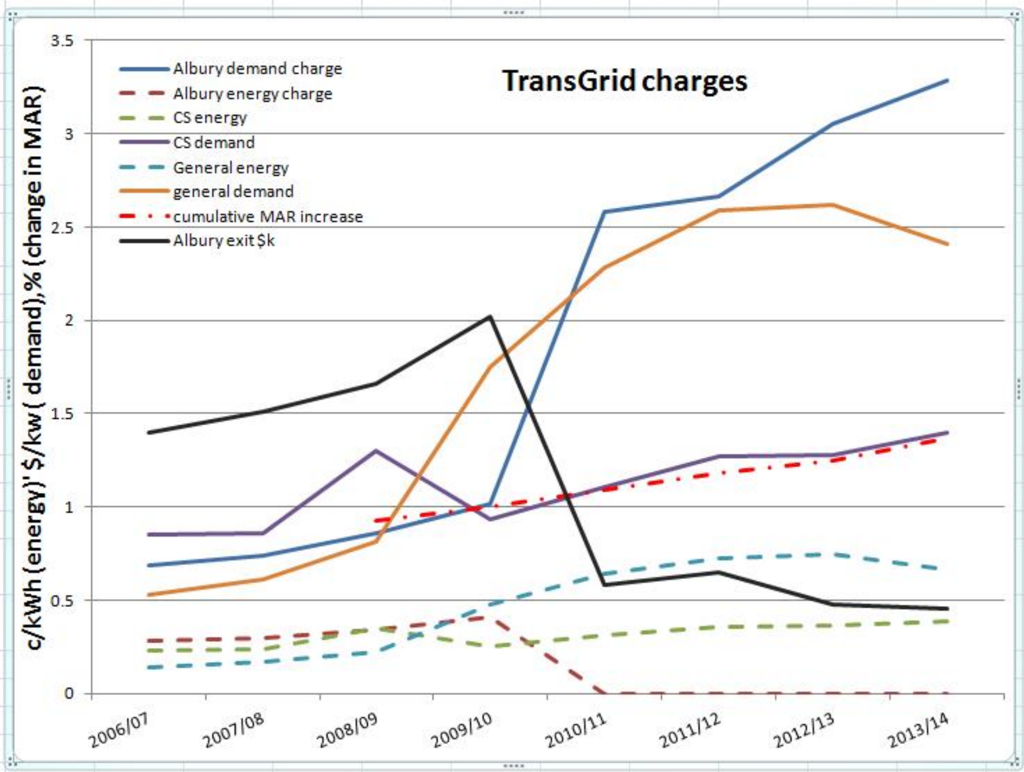
There are a number of aspects of the NCIPAP program that are not clear and the AER needs to ensure that consumers are made aware of how those projects that are allowed are to be addressed over time.

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

10. TransGrid Pricing methodology

The EMRF is extremely interested in the outcomes of the TransGrid pricing methodology. In a submission made recently to the AEMC on the proposed rule changes on distribution pricing, the MEU provided the following longitudinal assessment of TransGrid and Trasend 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.



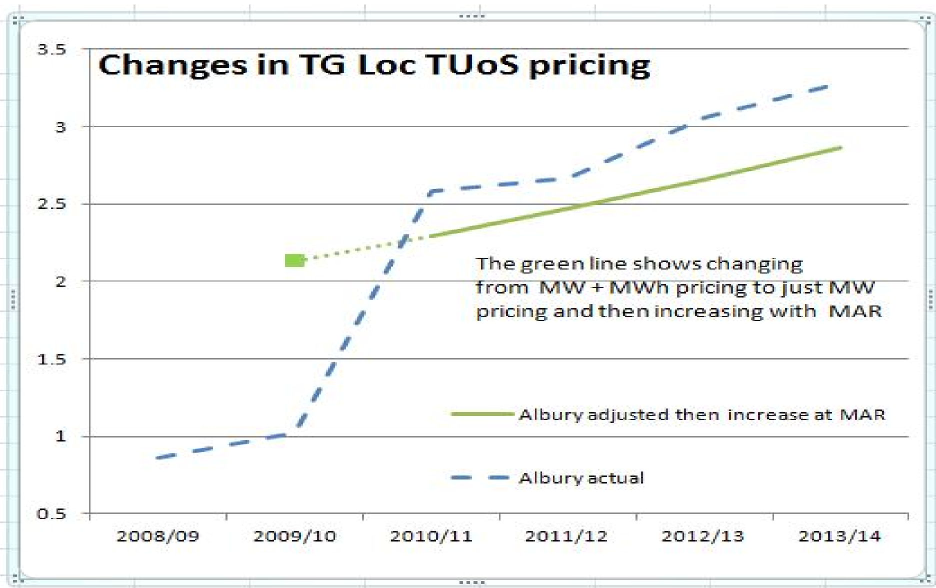
Source: TransGrid price lists

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.

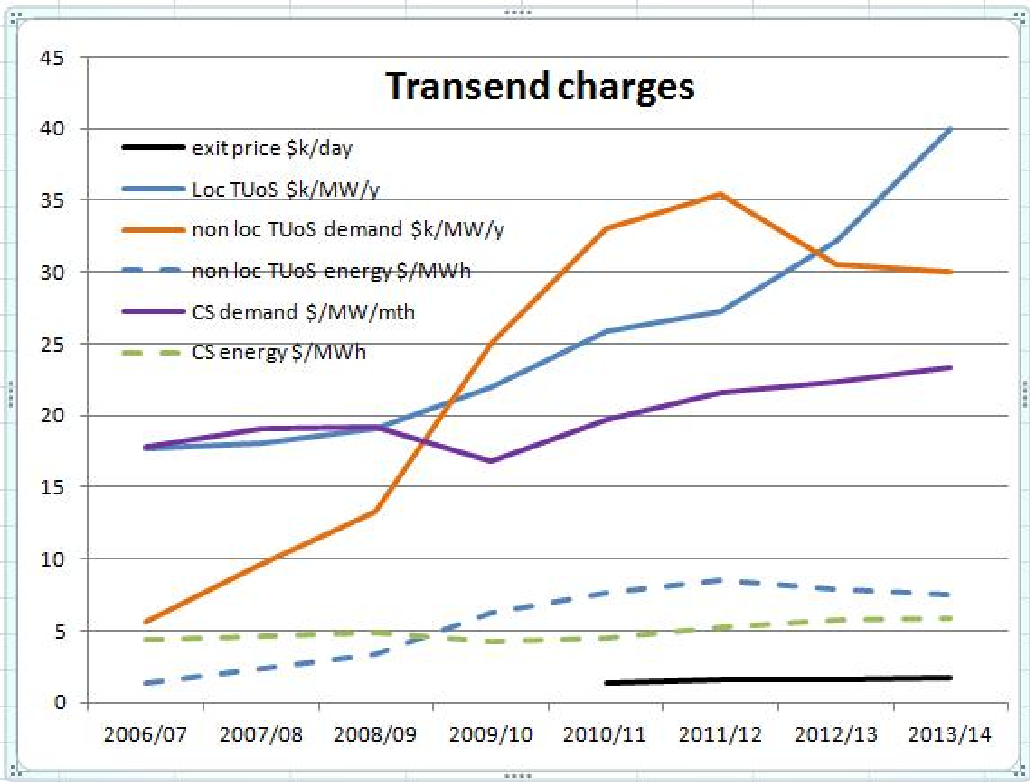
Directlink only provides a service to users on the north coast of NSW and the Ausgrid transmission elements are embedded in the Ausgrid distribution network thereby supporting Ausgrid distribution users. Despite this, TransGrid aggregates the transmission costs of both Ausgrid and Directlink into its 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.



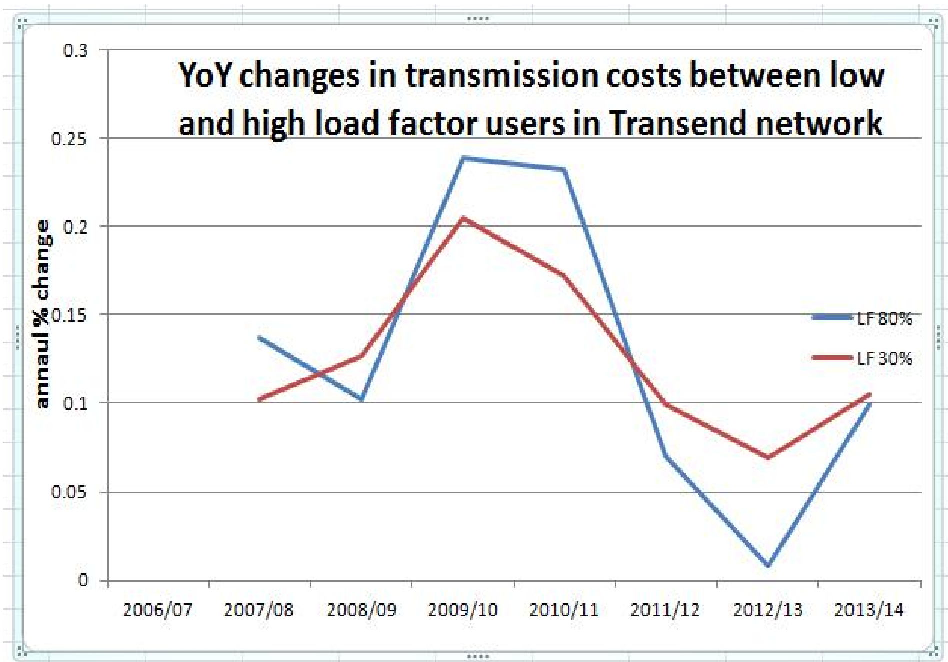
Source: Transend price lists

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)[13] 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

- 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.

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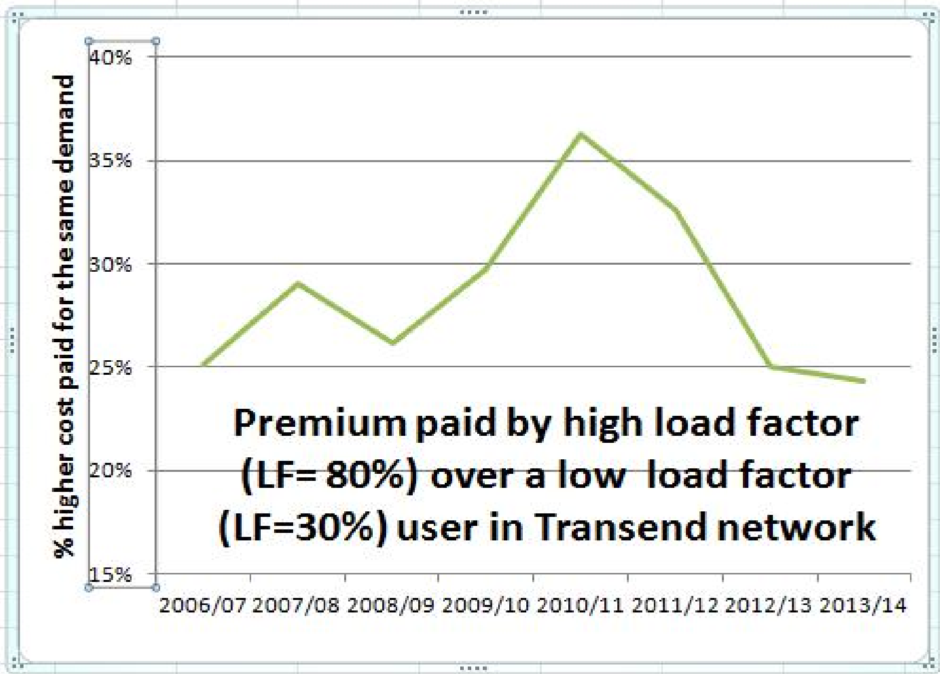
[13] The high load factor is typical of any one of the five largest users in Tasmania and the low load factor is the typical load factor on a state wide basis when the high load factor users are excluded.



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."

The EMRF is extremely concerned that TG 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 approved but the outcomes do not support that this requirement has been met.

The EMRF notes with pleasure the release by TG of the pricing methodology that results from the review TG undertook in recent months.

The EMRF considers that the new pricing methodology is a major step forward in ensuring transmission costs are shared equitably between all users of the services provided. Therefore the EMRF supports the new pricing methodology except the following elements which the EMRF considers must be made to the 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 EMRF considers that this does not send the appropriate signal to users to limit their usage when the network is most stressed. The EMRF 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 times. To set the peak demand at any time of the day does not encourage load shifting which results in higher overall load factor 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 EMRF 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 EMRF 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 to the transmission assets provided by other networks - currently this covers payments to Directlink, Ausgrid and ActewAGL. The EMRF considers that only those consumers that benefit from the transmission assets provided by these transmission asset owners should be charged for these assets - under the pricing methodology the costs of these peripheral 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. The EMRF 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 EMRF 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 EMRF has provided these views on the pricing methodology proposed, the EMRF considers there are still more changes that should be applied in order to get a more equitable outcome. The EMRF proposes that TG be required to carry out more consultation with its customers to improve the methodology

#	AER question	EMRF response
1	TransGrid has proposed an alternative pricing structure	The EMRF considers that the proposal is a "step in the right direction" and follows the lead

	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?	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[14]. The EMRF 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

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

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