Major Energy Users Inc.

Australian Energy Regulator

NSW Electricity Transmission Revenue Reset

TransGrid Application for Transition Year 2014/15

A response

by

Major Energy Users Inc

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Summary

The Major Energy Users Inc (MEU) welcomes the opportunity for presenting its views on the application from TransGrid for a reset of the electricity transmission costs in NSW for the transition year 2014/15.

The MEU is very concerned that the revenue for the transition year has been overstated. The MEU notes that this raises two very important issues:

- Community expectations are that there will be a considerable reduction in network revenues to reflect the rule changes that were introduced to achieve this outcome. If consumers do not see these reductions then there will be questions as to why the AER has not used its powers and discretions as they were intended - in the long term interests of consumers
- Even though there is expected to be a "true up" when the full review is carried out, as end user costs for capital are higher than those for regulated networks, an excessive allowance in the transition year will cause harm to end users even after a true up because of this disparity than the benefit that comes from a subsequent true up based on networks' cost of capital

Additionally, the revenue allowance for the transition year needs to reflect the reality that demand and consumption has fallen in recent years and that the revenue allowances in the current period included significant expectations of increasing demands and consumption. This means that the revenue allowance for the current period included amounts that were never needed and that there has been an over-recovery of revenue and investment in assets that was not needed.

To some extent, TransGrid's application for the transition year does refect these realities, in that overall capex claims are considerably lower than the capex allowances granted for the current period, and that the claims for the transition year do reflect very slightly lower costs. In contrast, the opex claim represents a significant increase on historical opex. However, even with the relatively static claimed revenue for the transition year there are a number of anomalies where claims have increased significantly above costs that were actually incurred.

The MEU has assessed the WACC, opex and capex claims:

- TransGrid approach to WACC is not acceptable to the MEU. The approach is a mish-mash of old and new. The MEU considers that, for the transition year, the WACC approach established by the AER for SP Ausnet transmission maintains consistency and recognises that more time is needed to develop and implement the detail for the new approach to WACC development. This additional time will be provided when the detailed review is carried out under the new guidelines

- The opex claimed for the transition year appears to reflect an unacceptably high step increase; analysis of this increase was made more difficult by the approach used by TransGrid to provide historic data using one approach and forecast data based on another approach. Additionally, the MEU is concerned that the full benefit of the EBSS reward for under cutting the allowed opex is being carried primarily by the transition year. This is not appropriate

- Whilst the capex claim for the transition year appears reasonable, deeper investigation indicates that it is overstated and should be reduced by some 40%

The MEU is most concerned with the NCIPAP claim and considers that some of the projects should be carried out under the normal opex and capex programs and others should not be accepted as the benefit to cost ratio is too small or non-existent. The MEU considers that the introduction of the NCIPAP in its current form is providing networks with rewards for doing little and, in some cases, doing work that is already paid for. The AER needs to examine the NCIPAP process closely to ensure that it does not result in consumers "paying twice for the same thing" and rewarding networks for doing little or nothing. It is unacceptable to reward networks just for carrying out a project without assessing whether the benefits that underpinned the project are actually delivered.

The current pricing methodology provided by TransGrid has resulted in some considerable anomalies and a loss of equity. It must be assessed in keeping with the basic premise that each user pays its "fair share" and that prices will generally move with the AER approved yearly change in revenue.

1. Introduction

The MEU has addressed this proposal from TransGrid as setting the revenue allowance purely for the transition year 2014/15. The MEU will therefore focus on the revenue sought for this year to ensure that the allowance reflects an equitable basis.

Whilst the MEU would normally address forecast costs in detail based on the long term performance of TransGrid, it appreciates for the current purposes that such detail is probably not warranted.

1.1 The scope of this review

There is an overall view that network charges (especially those with government ownership) have risen too much over the past 6-7 years and that the network revenue rules were biased in favour of the networks. Arising from this recognition, the rules on assessing network revenues were changed dramatically to redress what has been determined as over incentivising investment in networks and providing excessive revenues to networks. It was the AER that sought the rule changes that have been implemented to address this imbalance and it is up to the AER to ensure that there are better consumer outcomes by using the discretions now embedded in the rules applying to network revenue setting.

As a result of heavy involvement in the development of the new rules and the guidelines developed by the AER to implement the new rules, consumers have an expectation that the new rules and guidelines will result in significant reductions in network revenues. If this does not occur then all of the effort devoted in the changing of the rules will have been wasted.

Ambit claims (such as provided by TransGrid) and front loading of costs for the transition year allowance fly in the face of community expectations. The community also expects (as occurs in competitive markets) that declining demand and consumption should result in falling prices as providers struggle to maintain market share; yet what is seen in the network claims is that declining demand and consumption results in higher prices. To achieve community expectations of lower prices, requires the networks to reduce their revenues to offset the impact of lower demand and consumption. But this has not occurred!

The transition year revenues will be the first seen by consumers since the new rules were developed so the AER decisions on the transition year allowances will be seen as a test of the efficacy of the new rules and how well the AER will use its new powers.

The AER has traditionally allowed the networks to "smooth" the prices over the regulatory period and considers that "truing up" any over payment in the transition year can be achieved with lower prices in the subsequent years. In the current environment where large electricity using firms are reducing and even ceasing operations, such a true up is of little benefit.

Over the coming year, TransGrid is to provide the AER with a detailed application detailing its claim for a revenue stream to apply for the entire five year period 2014/15 to 2018/19. This revenue stream will be assessed under the new electricity rules and the recently published AER guidelines.

The MEU recognises that the AER decision regarding this transition year application from TransGrid will only provide a "place setter" amount of revenue for the transition year. When the AER releases its decision on the detailed application by TransGrid for the entire 5 year regulatory period, the AER will adjust the revenues for the last 4 years to reflect any over/under allowance made for the transition year.

In theory this might be considered to mean that there is little need to get the allowance for the transition year to be as close as possible to being correct. The MEU considers that just as much care needs to be devoted to getting the allowance for the transition "right" as would apply under any other regulatory decision. This approach is based on equity. It is inequitable for users of the services in later years to be liable for errors in revenue setting for the transition year.

Whilst the setting of the transition revenue is a "place setter" subject to a later "truing up" care must be taken to ensure that the transition year revenue is still in keeping with community expectations of overall lessening of network revenues. If the revenue for the transition year is higher than it need be, then end users will incur additional costs which they will have to fund at their cost of capital. Whilst a "true up" will be carried out using the networks' WACC, consumers have to fund over payments for the transition year based on the higher WACC that competitive markets achieve. This means that the penalty on consumers if the transition year revenue is set too high will be greater than the benefit from any "truing up" by the AER which is based on networks' WACCs[1].

There is no doubt that users and the services they utilise will be different in the transition year to those in the subsequent years. It would be inequitable to require a temporal cross subsidy between users where the cause is attributable to such a significant change in approach.

1.2 TransGrid past performance

The MEU notes that the regulatory decisions for the past three regulatory periods have massively increased TransGrid annual revenues: from 1999

[1] The AER has, in the past, used the networks' WACC to smooth the revenue stream but firms in the competitive market have (or should have) higher WACCs than the networks as they face greater risks. For the AER to smooth the transition year revenue will therefore not recompense end users for the additional costs they incur as a result of a higher than needed revenue allowance for the transition years

when TransGrid had been allowed ~$330m (nominal) annual revenue to $820m (nominal) in 2013/14. Over the same period inflation has increased by ~54% implying that the increase in transmission revenue has increased by more than 60% in real terms.

At the same time, the volume of electricity transferred has increased by just 1.3% and the peak demand has increased by just 21% (which occurred in 2009 and has since fallen by ~4%). Overall, the quality of service provided has not significantly changed. NSW consumers have great difficulty in understanding why the transmission costs have risen by so much in comparison to the service required by consumers.

TransGrid is proposing a further increase in revenue of about 9% for the transition year compared to the revenue allowed for 2013/14 (and even more as TransGrid has imposed a freeze for revenue for 2013/14). At the same time, the allowance for 2013/14 reflected a massive increase in its revenue over the last decade.

The proposal clearly shows that the revenue allowed for the last period was grossly overstated because TransGrid used less capex and just over $10m pa less opex than they were granted at the last review. To reflect this lower cost than allowed, TransGrid comments that (page 5)

> "TransGrid is responsive to the changing world. It has deferred over $600 million of capital expenditure in response to changes in electricity demand patterns. Consumers directly benefit from these decisions in this revenue proposal, with forecast revenue over the next five years some $230 million lower due to the deferrals. TransGrid has connected renewable generation, pursued low-cost methods of improving the capacity of flow paths and improved project initiation and delivery processes to be able to respond more rapidly when short notice needs arise."

The MEU is pleased that TransGrid decided to freeze the revenue for 2013/14 (although some consumers reported an increase in prices between 2012/13 and 2013/14 which casts doubt on TransGrid's claim and might imply that TransGrid provided a cross subsidy between consumer classes) but it also notes that, whilst such a reduction in revenue was made, the reductions were far less than the over-recovery TransGrid was achieving over the period against its lower actual opex and capex. What is more, TransGrid is claiming the full benefit of the Efficiency Benefit Sharing Scheme (EBSS) in the forecast revenue for its actual opex being lower than the allowed opex, further offsetting the value of the benefit of the lower revenue.

1.3 Customer and consumer engagement

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

The MEU is pleased that this engagement has occurred but is still concerned 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 17)

> "In the deliberative forums with residential and small business consumers, TransGrid sought views on consumers' willingness to pay for reliability. Responses showed that almost two thirds of consumers are willing to pay an increase of around $4 per year, which is within CPI, to maintain current levels of reliability. Almost one third 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. Additionally, it is demonstrably the distribution networks that cause the poor reliability to most consumers rather than TransGrid. The MEU is also concerned that consumers are unaware that TransGrid is increasing its charges by more than this amount just to provide the same level of service.

The MEU notes that TransGrid proposes to increase its demand management innovation allowance which is a cost increase 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 included in the transition year costs as there has been no detailed assessment of the benefits (if any). TransGrid is also seeking additional funding to address consumer engagement. Whether the increased costs will deliver better outcomes is still to be demonstrated.

Although the MEU is concerned about the detail and approach by TransGrid, the MEU recognises that the consumer engagement process will, hopefully, improve over time, to the benefit of both consumers and TransGrid.

1.4 Forecasts of demand and consumption

The amount of energy used within NSW rose from 1999 levels to peak in 2009 but since then consumption has fallen to 2003 levels and the expectation is that consumption will continue to be static or even fall further.

Although the most recent full year peak demand showed an increase on the previous year's much lower demand, this was for a single day and the peak demand for the year 2013/14 so far shows a reduction from the rise seen for 2012/13, to the low peak demand seen in 2011/12 year. The forecast peak demand (10% PoE) is not expected to exceed the highest recorded peak demand in NSW (2009/10) in the next regulatory period, reflecting a general trend in the NEM.

Based on this data, there is little expectation for a need to significantly augment the TransGrid network in the next 5 years but particularly there will no need to augment the network during the transition year.

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 AEMO costs, this statement has validity.

However, it must be recognised that transmission costs can be a significant element of a consumer's bill, as 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. In fact, MEU members have seen transmission charges increase dramatically over the last 5 years! This has come against a backdrop of a continuing high currency rate exchange and tough trading conditions for trade exposed businesses. The issue that needs to be addressed is not the share of the electricity bill but the quantum of the increase. No MEU member has reported any other element in their cost structure that has risen by the amounts claimed by TransGrid.

It is, therefore, essential that transmission costs are <u>not</u> treated as insignificant, and are addressed in a comprehensive manner.

1.6 The helicopter view of the TransGrid proposal

TransGrid highlights that it's allowed maximum revenue will increase from 2013/14 for the transition year and into the next regulatory period. The MEU finds that this is anomalous when considering that TransGrid did not use its allowed capex and allowed opex in the current period. TransGrid proposes to marginally reduce its overall capex but increase its opex considerably despite under-running its opex allowance in the current period.

TransGrid implies that its revenue freeze for 2013/14 resulted in the average tariff being about $1/MWh lower than might have occurred if it had claimed its maximum allowable revenue. The MEU notes this and is appreciative of the action taken but from the MEU viewpoint, this highlights that the revenue allowed in the previous review was excessive.

From the revenue being collected under the revenue freeze, TransGrid seeks a step rise in the average tariff for the transition year and indicates a marginally falling real tariff over the rest of the next regulatory period. The MEU finds this difficult to accept when the revenue rises significantly over the period yet the forecast consumption is expected to remain basically static and might even continue its downward drift.

The import of the TransGrid proposal is that consumers should be pleased with what TransGrid is proposing. However, as noted in section 1.2 above, TransGrid costs have risen massively over the past decade, despite peak demand and consumption falling significantly in recent years. So when seen in this context, the TransGrid proposal is a continuation of the current trend, albeit with a degree of "flattening" the historic price rises, despite there being a massive reduction in demand and consumption and little change in the service standards.

1.7 Escalation of costs

As the AER is only to assess the revenue allowance for 2014/15 year under the transition year process, TransGrid has not provided any support for escalation of opex and capex costs. Yet TransGrid comments (page 27) that for its capex:

> "[TransGrid] applies escalation for labour, commodities and property. Projects are costed in 2013 year dollars and then escalation is applied to reflect the relevant timing of the expenditure within the regulatory control period."

And on opex (page 43) TransGrid comments:

> "…operating expenditure forecast includes escalation for network growth, adjusted for economies of scale. It also includes labour rate escalation based on the wage price index (WPI) for the electricity, gas, water and waste services (EGWWS) sector in New South Wales.

There is no detail to indicate to what extent escalation of costs has been included in the transition year costs (or any other year) other than TransGrid has assumed an inflation rate of 2.53% will apply between 2013/14 and 2014/15.

The MEU considers that, for the purposes, the transition year assessment should only include for expected inflation and not include for any other escalation, especially as TransGrid has not provided any indication as to what this "real escalation" on opex and capex might be.

2. TransGrid WACC and "pass through" of risk

2.1 WACC

In its transition year proposal, TransGrid seems to propose a weighted average cost of capital (WACC) (although it is not clear what inputs TransGrid has used to develop its WACC) applicable to its transition year should be based on the new AER guideline. TransGrid does offer its views on what the new guidelines will achieve (or not) and that the new approach will put a downward bias from the AER's return on equity model - something that TransGrid does not agree with along with the AER decision to implement transitional arrangements for introducing the new guideline for return on debt[2].

However, it is clear that the AER has not yet developed in full, the implementation details of the new approach, and neither has TransGrid. This then raises the issue as to whether the AER should attempt to implement the approach *for the transition year* to WACC development under the new guideline or under the old guideline. The MEU is firmly of the view that *for the transition year only*, the WACC should be based on the methodology and parameters used most recently, such as in the SP Ausnet (SPA) transmission review and released on 31 January 2014.

It is recognised that the new guideline includes for considerable discretion by the AER and for the AER to exercise this discretion in a foreshortened review process could lead to unnecessary concerns and unintended outcomes. As the transition year allowed revenue will be adjusted for any overs/unders later in the regulatory period after the new guideline methodology has been tested within a full review process, it would be equitable to apply the historical approach to setting the WACC for the transition year.

Adopting the recent past approach to setting the WACC for this transition year should be non-controversial and, if anything, favour the regulated firm as the recent rule changes were introduced in order to bring greater balance to regulatory decision making and, in particular, to introduce a realistic methodology for assessing the cost of debt considering that the Competition Tribunal and consumers have been so critical of the AER's previous methodology.

The MEU is most concerned that TransGrid has elected to approach the setting of the WACC for the transition year based on a variety of inputs reflecting both the old and the new approaches and has done so in a way that results in a higher WACC than might be expected when viewing the current relatively low risk free rate. TransGrid seems to have utilised those elements of the old

[2] The MEU agrees with TransGrid that there is no need for transition arrangements for moving from the "on the day" approach to a trailing average approach and made this point in its submission to the AER on the approach to return on debt.

approach which increases the WACC (such as equity beta and gamma) and then overlaid elements of the new approach which further increases the WACC.

TransGrid has offered no inputs on which to develop its WACC and what inputs TransGrid appears to have used are included along with the AER decision for SPA inputs and parameters. The upper and lower bounds and the proposed nominal vanilla WACC with the AER decision on SP Ausnet transmission are shown in the following table:

	TransGrid approach			AER on SPA
Parameter	**Lower bound**	**Upper Bound**	**Proposed**	
Risk free rate (nominal)	Prevailing rate	Prevailing rate	Prevailing rate	4.31%
Market risk premium				6.5%
Equity beta				0.8
Cost of equity				9.51%
Cost of debt - 10 year BBB+ (nominal)				6.79%
Expected inflation	2.53%	2.53%	2.53%	2.45%
Gearing (D/V)	60%	60%	60%	60%
Gamma	0.25	0.25	0.25	0.65
Corporate tax rate	30%	30%	30%	30%
Vanilla WACC (nominal)	**8.8%**	**9.5%**	**8.9%**	**7.87%**

The MEU considers that the only change the AER should make to their SPA assessment when applying it to TransGrid is to assess the risk free rate as has been previous practice and recalculate the WACC based on the risk free rate applying at the time of the final decision. The approach to the cost of debt used for the SPA electricity transmission is the most recent assessment of debt made and this applies equally to all regulated energy networks.

2.1 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.

In the current Rules there are defined elements where the "pass through" of actual costs is permitted. However, 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.

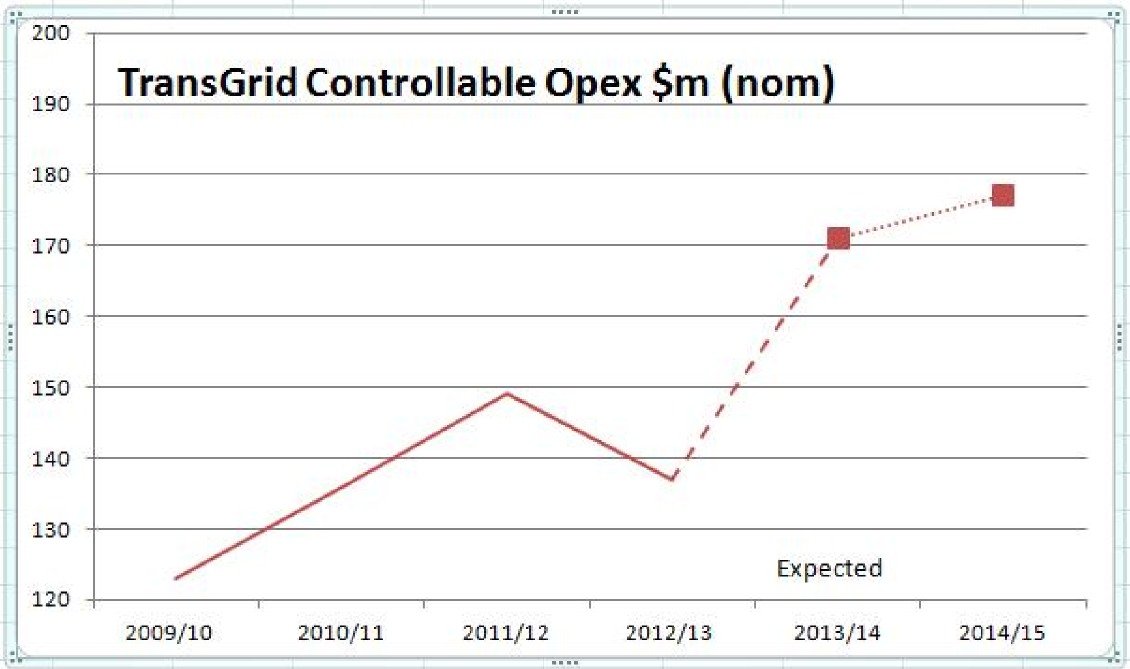
The request by TransGrid for a pass through provision for the transition year would appear, prima facie, not to be necessary. This is because of the short period between the setting of the allowed revenue and the termination of the transition year. Further, the allowed revenue for the entire regulatory period will be set early in 2015 and there will be an adjustment made to reflect the difference between the revenue allowed for the transition year and the decision made for the revenue applicable for first year of the regulatory period under the new rules.

The revenue allowance for the transition year is a "place holder" allowance which has been developed under a foreshortened regulatory review. This precludes a detailed assessment of the conditions that would constitute a "pass through" event. On this basis, the conditions for a "pass through" should be based on the current "pass through" provisions but for these to be adjusted should there be a change made to the provisions for "pass through" when the full regulatory review under the new rules is carried out for the nest regulatory period.

3. TransGrid Opex and EBSS

The following chart has been developed from data in the TransGrid application for the transition year (tables 5.1 and 5.5). Tracking the comparable AER allowance for the current period is difficult based on the information provided by TransGrid. However, it is quite apparent that TransGrid considerably under-run the controllable opex allowance when assessing the claim for the EBSS pass through of benefits (table 11.1) which implies that TransGrid achieved an average of nearly $14m pa saving on its controllable opex.

What is most concerning is that the chart shows a massive 25% increase in opex expected from 2012/13 to 2013/14, with the opex for the transition year increasing even further.



Source: TG application 2014, AER FD

What further complicates comparisons is that TransGrid has costed the historic opex on inclusion of entitlements on a provisions basis yet based its forecast on a cash basis. TransGrid attempts to reconcile these differences in figure 5.2 using $m ('13/14) which further complicates comparisons. Analysis of figure 5.2 raises more concerns:

- why is the effect of the two approaches different between the historical data and the forecast data[3] where the impact of the provisions basis is

[3] The MEU would expect that, on average, making provision for entitlements would result in a higher cost as some staff leave before they can collect their long service leave entitlements and leave accruals are paid at a higher rate than when the leave was a accrued. Cash payment of entitlements might be

less than the cash basis but in the forecast, the cash basis is less than the impact of the provisions basis?

- why there is such a significant difference in cost between the historical actual/estimated opex costs between the two methods (averaging a volatile $14m pa) but this is not replicated in the forecasts using the same method which show a consistent but negative $6m pa?
- why is there such annual variation in the historic costs between the two methods (the variances range from $0 for 2013/14 but are as high as $25m in 2012/13 (the base year)? The MEU would expect that the accrual on a provisions basis would show considerably less volatility than entitlements recoded on a cash basis
- what occurred in 2010/11 that caused the opex assessed on a cash basis to increase by $18m (or 13%) but only caused opex assessed on a provisions basis to rise by $8m (or ~5%)?
- what occurred in 2012/13 that caused the opex on a provisions basis to fall so markedly by $18m (or 13%) but which had no impact on opex assessed on a cash basis?
- why has TransGrid assumed that opex based on cash entitlements will equal opex with provision for entitlements in year 2013/14? This doesn't make sense (see footnote 2)

There is significant concern that the information provided by TransGrid is severely flawed and this has biased the opex claimed for the transition year relative to the historic opex.

The base-step-trend approach

If the traditional approach to setting the controllable opex was followed, the opex for 2012/13 would be used as the base year and step changes allowed for the setting of the opex for the transition year and on. Although the AER has previously expressed a strong view that the base-step-trend approach is to be used universally (and this is reinforced in its new guideline) TransGrid has used a mix of approaches including zero base year, and (base year unit rates)*(forecast work volumes) which is effectively a modified zero base approach.

TransGrid comments that "major operating projects" is similar in nature to capital works and therefore should be assessed on a zero base approach. The MEU disagrees. A zero approach to capital projects is only applicable where the works are truly "lumpy". Where there are many small projects, a base-step-trend approach is valid. Ongoing maintenance is a series of small projects but lends itself well to a base-step-trend assessment. The MEU members are all capital intensive firms and they calculate their forecast opex on the basis of previous years' performance with a requirement to reduce the allowance. In

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higher than accruing entitlements where staff numbers reduce but the increasing cost of opex indicated by TransGrid does not indicate that this is the reason for the variance.

contrast, TransGrid is fortunate to be allowed increases by the regulator. Using a zero base approach provides an avenue to get increased allowances that are not needed.

TransGrid asserts that its approach of using a mix of different approaches for different elements results in

> "…a more accurate forecast" (page 38).

The MEU observes that it certainly results in a greatly inflated outcome!

TransGrid notes that the lower than expected actual opex for 2012/13 resulted from its easement clearing contractor not completing $2m of clearing work[4]. This implies that the base year should be increased by this amount to provide a valid base year. On provision of evidence of this, the MEU would accept that the base year should be increased by $2m to $139m. At the same time, the MEU is concerned that TransGrid will use the lower amount as the basis for its EBSS calculation, thereby making a virtue of the lower costs and getting restitution from consumers for not doing anything. TransGrid adds that it will increase opex in the future to carry out the work not done, further increasing consumers' costs.

The MEU has other concerns with the projected increase to 2013/14. In the final decision of the AER in 2009, TransGrid was awarded annual increases in controllable opex averaging ~3% real. The actual increase over the period as indicated by TransGrid is ~9% nominal (or over 6% real). The actual EBSS claimed by TransGrid (table 11.1) shows that the benefit increases towards the end of the period, implying that the actual rate of change for TransGrid opex has been less than the rate of change set by the AER for opex. There appears to be a number of inconsistencies in the data being provided by TransGrid, making assessments of the TransGrid claims more and more contentious.

In table 5.2, TransGrid advises that there are $2.8m pa step change savings on the base year and, in table 5.3, step change increases of between $6.8m pa and $8.9m pa. Without discussing the merits of the step changes, this results in a net increase of between $4m pa and $7.1m pa. Neither of these justifies the $55m increase from the base year to the 2014/15 forecast and beyond when comparing the allowances on the provisions basis that TransGrid states it prefers.

TransGrid has not provided any breakdown of the controllable opex so the MEU is not able to comment on the detail of why elements of the opex claimed might be reasonable or otherwise. This lack of detail prevents any ability to "drill down" into the causes of the opex increases which might allow the MEU to

[4] The MEU notes that a reduction in opex for 2012/13 is clearly seen in the opex recorded on a provisions basis but there is no discernable reduction in the opex shown on a cash basis for entitlements (see figure 5.2) reinforcing the MEU that the data provided is not consistent.

support some aspects of what is overall an apparent attempt by TransGrid to be provided with an excessive allowance for its opex for the transition year.

EBSS

Table 11.1 shows that TransGrid considers that it is entitled to a reward under the efficiency benefit sharing scheme (EBSS). Table 11.2 quantifies the carryover of this reward into the next regulatory period.

Table 11.1
Historical EBSS Performance ($m nominal)

	2009/10	2010/11	2011/12	2012/13	2013/14
EBSS Target	121	135	142	154	159
EBSS Target Adjusted for Change in Demand	121	135	141	152	157
Actual/Expected EBSS Expenditure	108	123	137	132	137

Source: TransGrid.

However, it must be noted that the allowance provided at the last reset significantly overstated the opex requirement when compared to the actual performance of TransGrid during the current period. The opex allowance sought by TransGrid and allowed by the AER showed total opex increasing by over 6% in real terms from 2009/10 to 2013/14, whereas in real terms, actual total opex increased by a much lesser amount over the same years. In table 11.1 TransGrid shows that the actual total opex for the base year (2012/13 was over 15% lower than the opex allowed!

Whist the MEU supports the provision of a reward for achieving lower costs for passing onto consumers, the process its self is heavily biased by the ability of the network to "game" the regulator. For TransGrid to have achieved such a significant reduction in opex implies that the original allowance was grossly overstated. The fact that this point was made by consumer stakeholders at the revenue reset yet the excessive allowance was provided.

Under the EBSS, TransGrid is entitled to a bonus for its efforts in reducing its opex, on the basis that his benefit is passed to consumers in terms of the future opex allowances. For the revenue allowance for the transition year, TransGrid is targeting to recoup all of the opex under-runs for the current period as a charge to the transition year revenue. Effectively the EBSS benefit for the opex under-run in the current period (calculated by TransGrid to be $21m pa) has the effect of increasing the "real" opex allowance (ie the sum of claimed opex plus the EBSS which is opex carried forward from the previous period) for the transition year by some 12% and has 40% of the EBSS reward being recovered in the transition year.

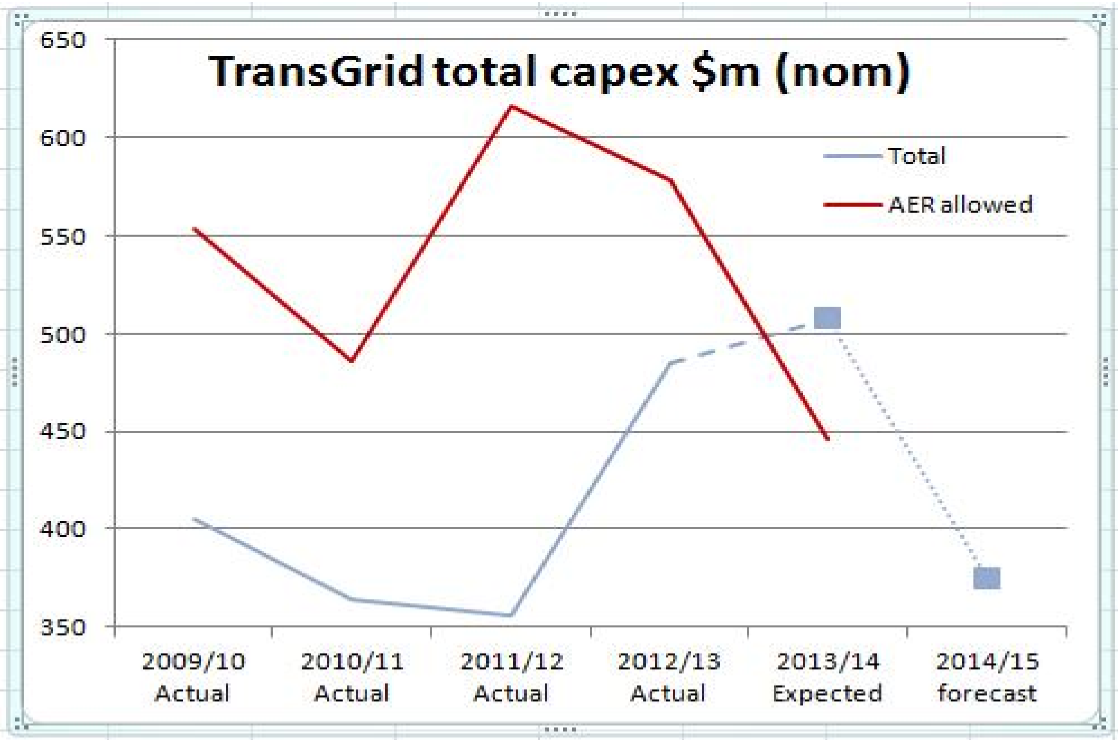
If a full five year period was to be set for the payment of the EBSS, the high cost in the early years would be amortised over the entire 5 year period. As the payment for the EBSS reduces over the 5 years of the next period, it is unreasonable for the first year to be levied with the bulk of the EBSS reward.

The MEU considers that the EBSS reward should be amortised equitably over the entire regulatory period both directly and through the smoothing approach and not to be so heavily imposed on the first year of the period.

4. TransGrid Capex

TransGrid capex for the NSW transmission system is presented in the following chart showing the actual capex in comparison to that allowed for the same period. This shows that that in four of the five years of the current regulatory period, TransGrid significantly used less capex than was allowed by the AER at the last revenue reset.

In aggregate terms TransGrid used only 80% of its allowed capex and as a result achieved a significant benefit of over $180m from this under-run in capex



Source: **TG application 2014, AER FD**

The capex proposal by TransGrid for the transition year would appear to reflect the recent downward trend in capex seen over the current period. The MEU considers that what TransGrid has achieved in its capex reductions is commendable and would <u>appear</u> to set a reasonable estimate for capex for the transition year.

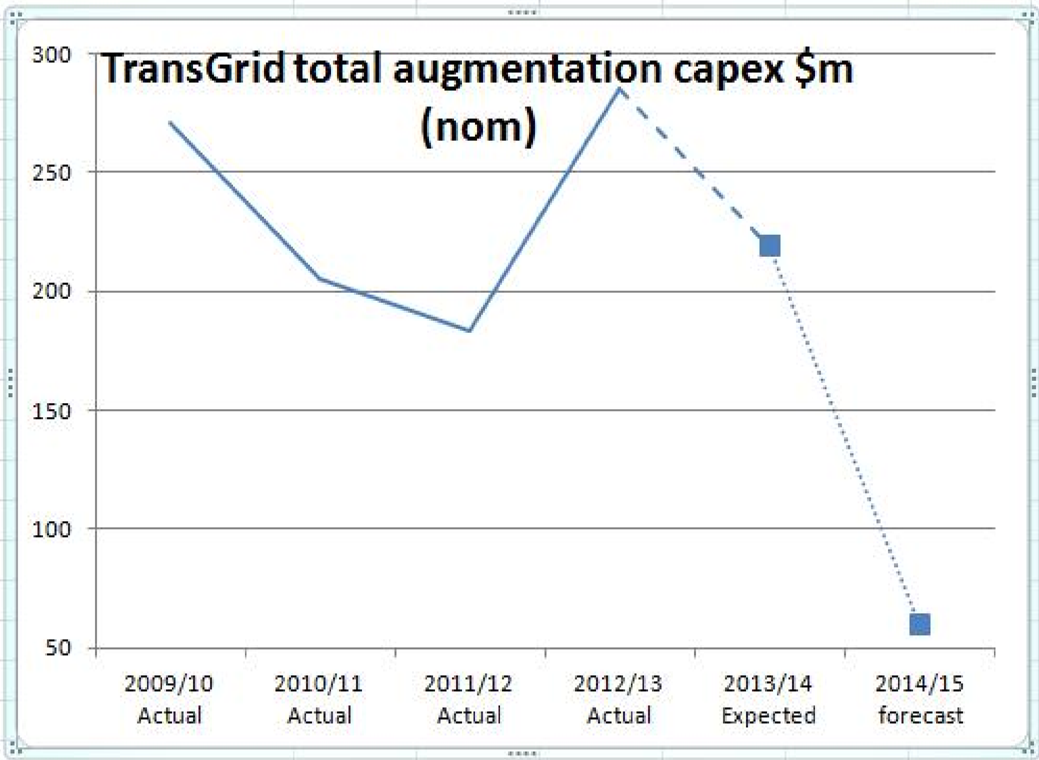
In most cases the allowance for each element of capex continues the general downward trend shown over time where the capex claim for each element is either equal to or lower than the recent past performance, although there are exceptions such as replacement capex[5] where the step increase from the base

[5] The MEU notes that a base-step-trend approach to replacement capex is reasonable as the amount of replacement needed is fairly consistent over time.

year to the transition year is 70% and security and compliance systems where the increase is 500%.above the base year.

Analysis of the individual elements of the capex shows that there is considerable variance in the historical capex and the allowance sought for the transition year. For example:

- Augmentation capex sought for the transition year (TransGrid table 4.1) supports a general view that there is little need for any augmentation as demand and consumption are falling. This is shown in the following chart:

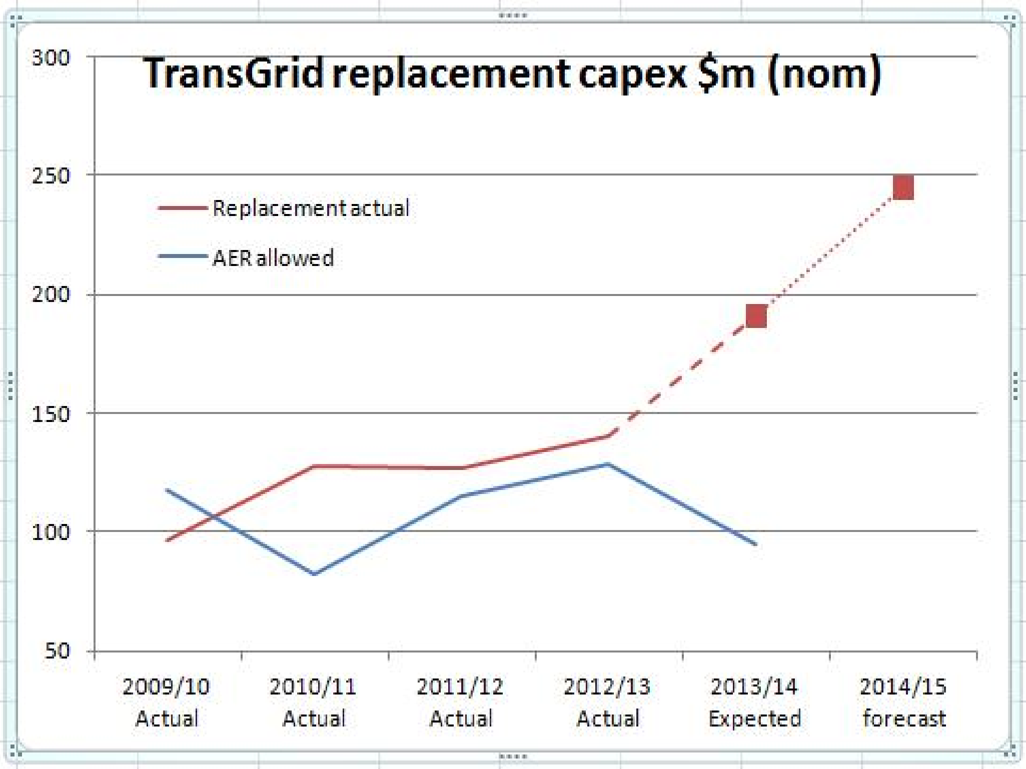


Source: TG applic

Whilst the amount claimed for the transition year is considerably lower than TransGrid used in recent years, TransGrid is still seeking over $50m in augmentation capex despite falling demand and falling consumption. It is also important to note that TransGrid had been allowed considerably more capex than it actually used for growth assets. TransGrid was allowed considerably more capex for augmentation than it actually used.

The MEU highlights that the bulk of the augmentation capex was incurred in the early stages of the regulatory period to meet the expected growth which did not occur. This means that the augmentation capex has provided more capacity than is currently required, supporting a view that little growth capex is needed for the transition year, and raising doubt as to whether $50m of capex is required for the transition year.

- In contrast, TransGrid overspent its capex allowance for renewal by some over $140m and this offsets to some extent the under-run on augmentation capex. As the AER accepted the TransGrid proposal for replacement capex, TransGrid also overspent against its own forecast for replacement works. The trend of renewal capex is shown in the following chart.



Source: **TG application 2014, AER FD**

By overspending on renewal capex during the current year, TransGrid has effectively "pre-installed" the bulk of the replacement capex of the $245m that it seeks for the transition year.

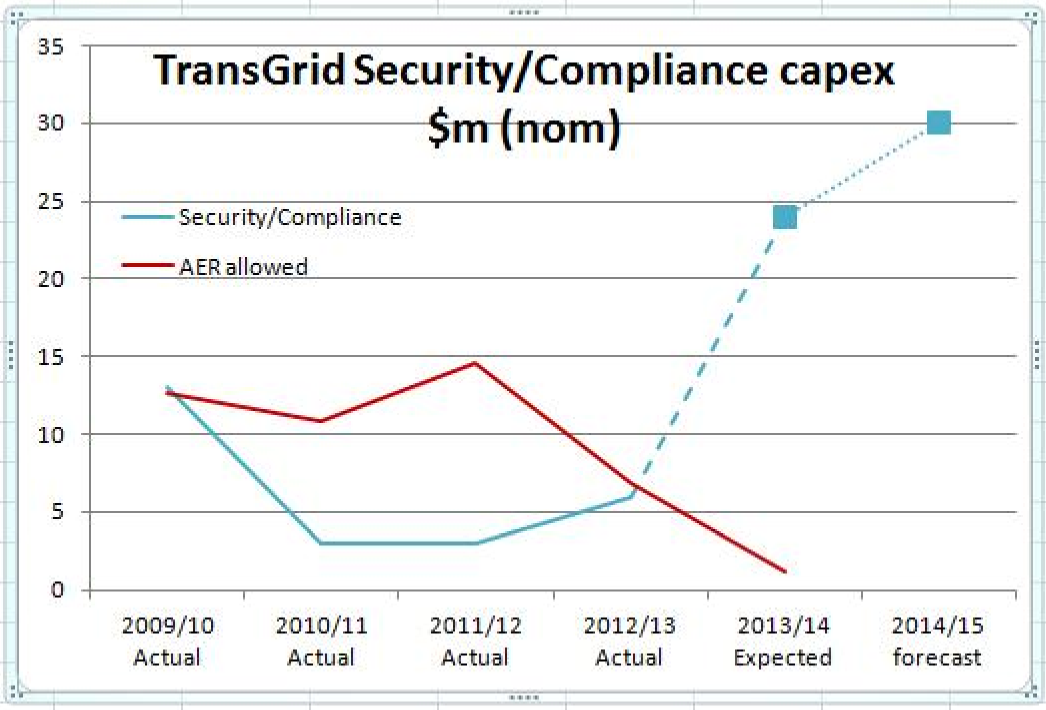
In addition, the amount of renewal capex sought for the transition year is a significant step up from the replacement capex seen as necessary in the past. Replacement is required for assets that are past their "use by" date but history has shown that most electricity network assets have useful lives well beyond the notional life set for depreciation purposes.

There is a general expectation that replacement capex would tend to reflect an allowance which would follow a reasonably predictable and consistent path and have little volatility over time. On this basis, replacement capex sought for the current period would be based on this consistent and predictable need. This approach implies that the replacement capex for the transition year should trend with the forecast provided by TransGrid in 2008 and accepted by the AER for the current period (ie ~$100m pa) or, at worst, with the revealed actual replacement capex (ie ~$125m pa). Neither of these approaches delivers an outcome replicating the $247m sought for the transition year.

The MEU considers that TransGrid needs less than the $247m it seeks for the transition year based on the historical trends which imply an amount of less than half what is sought. As TransGrid has already overspent on replacement capex in the current year, the allowance for the transition year could well be even lower than that deduced from the long term trend.

- A similar observation is made with regard to security and compliance capex as the following chart shows

.



Source: **TG application 2014, AER FD**

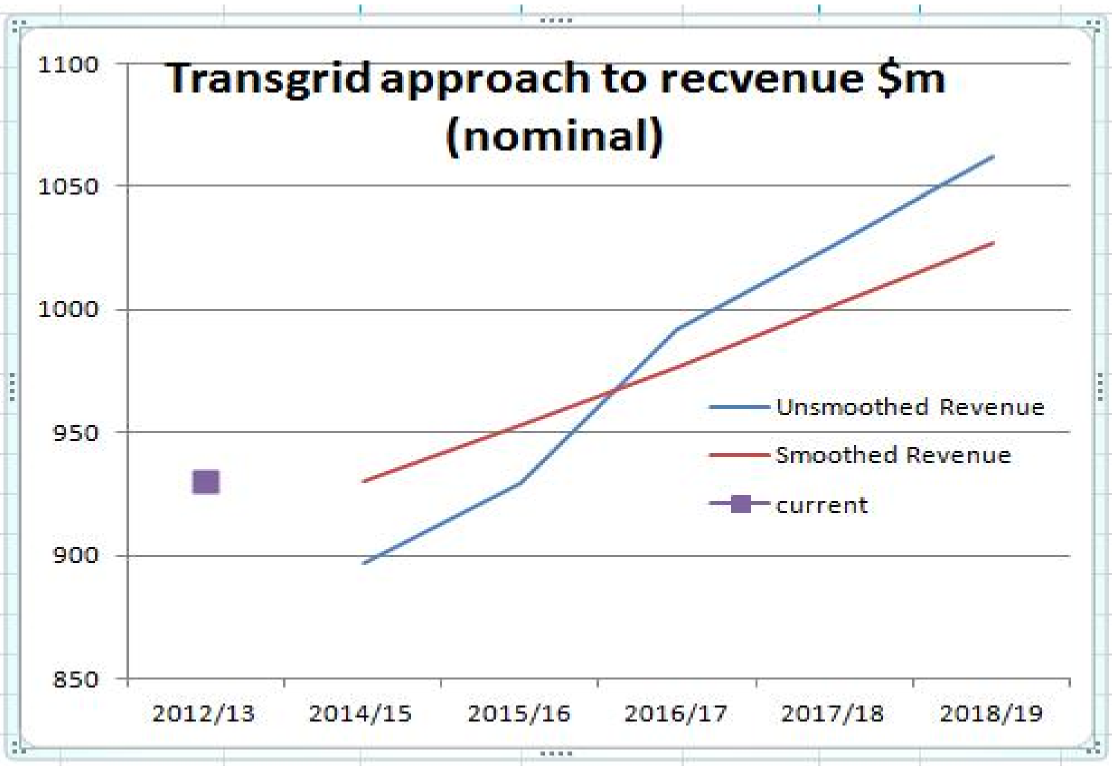
Here, TransGrid has so far under-spent its current period allowance by over $20m and looks to use all of the underspend in the final year to support is claim for a further increase for the transition year. From the base year, the step increase for the transition indicates a rise of 400%

Based on its past performance the allowance for security and compliance for the transition year should only be between $6m and $8m.

Overall, whilst the capex claim for the transition year appears to be reasonable, the MEU considers that it is higher than it needs be by at least $150m which implies the claimed capex is probably too high by some 40%.

5. Revenue approach and smoothing

TransGrid has identified that its revenues for the next five years will start at the same level as 2013/14 and then be static in real terms. This is shown in the following chart.



Source: TG application, AER FD

What is concerning is that TransGrid has decided that it will smooth the revenue it seeks for the transition year to reflect a small reduction (in real terms followed by a constant revenue in real terms for the remaining four years. The outcome of this approach is that the revenue for the transition year will be artificially increased. Based on the application the artificial increase in the transition year revenue is over $30m. That is, TransGrid will recover $30m more than it has estimated as being the appropriate revenue allowance for the transition year alone.

There is no certainty that the AER will allow TransGrid either the transition year allowance assessed or the forecast revenues for the following four years under the new rules and guidelines. In fact, there is an expectation that the new rules and guidelines will reduce the revenues allowed under the old rules and guidelines - otherwise why were the rule changes needed!

The MEU considers that the transition year assessed revenue needs to be set as a stand alone estimate, not adjusted for smoothing as TransGrid has done. On completion of the full review under the new rules there has already been made provision for smoothing the unders/overs between the allowed transition year revenue and the revenue for the year assessed under the new rules.

There is no need for smoothing the transition year allowance as has been done by TransGrid.

6. NCIPAP

TransGrid has provided a table (appendix A, 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 benefit, the average payback for the other 27 projects is about 6.2 years based on the benefits calculated by TransGrid.

As a general observation it would appear that, because these projects have not been carried out as part of the normal capex approach, 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 certainty that the value of the penalty will exceed the value of not carrying out the project providing the network with a reward for doing nothing.

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

The NCIPAP process is totally dependent on the network gaining agreement from AEMO that the projects identified will deliver a benefit to consumers. TransGrid has nominated 28 projects for the NCIPAP yet TransGrid only asserts that AEMO has reviewed the program and presumably endorsed all of the projects.

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.

- A detailed review of the projects indicates that only 12 would deliver a payback in two years 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 but no explanation is provided as to what this value is, where it is derived from and how "firm" the benefit derived from 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 no indication as to how the NCIPAP costs are to be integrated into the allowed revenue. In section 4.8, TransGrid comments that the capex allowance sought excludes

> "…expenditure to improve performance under the Service Target Performance Incentive Scheme (STPIS) or for projects included in the Network Capability Incentive Project Action Plan (NCIPAP). Appendix A provides details on the Network Capability Incentive Project Action Plan."

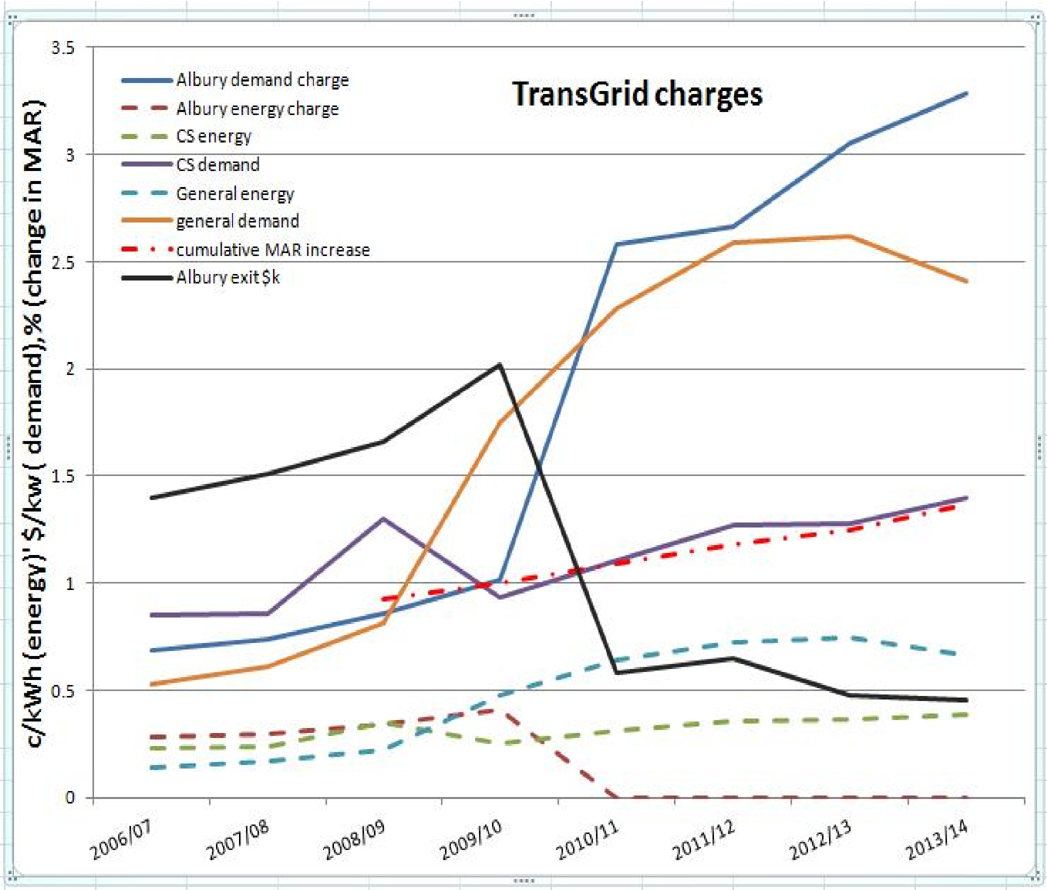
The MEU seeks advice as to what amount has been included for the NCIPAP in the transition year costs.

7. Pricing methodology

The MEU is extremely concerned about the outcomes of the TransGrid pricing methodology. In a submission made recently to the AEMC the MEU provided the following longitudinal assessment of 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.



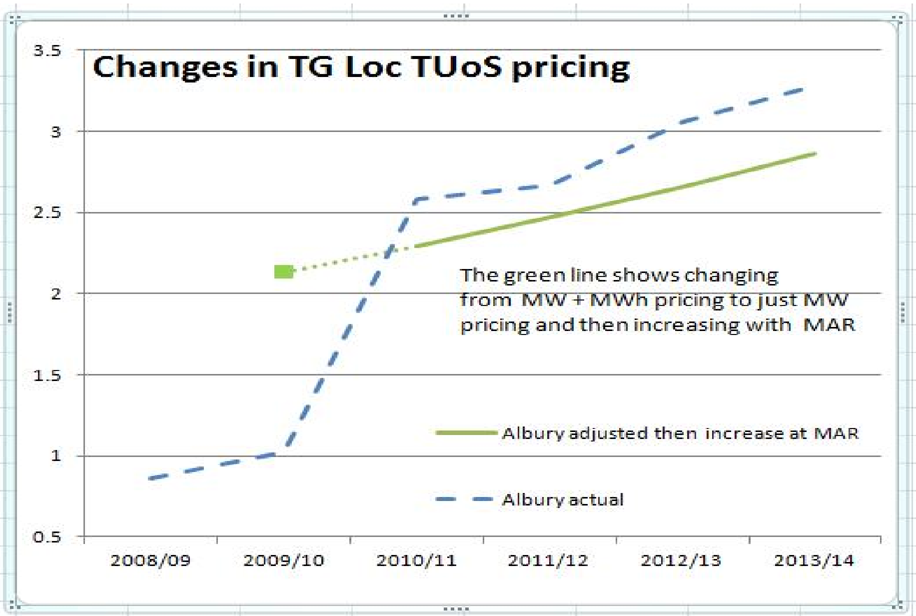
Source: TransGrid price lists

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."

The MEU is extremely concerned that TransGrid 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 this requirement.

The MEU accepts that in the foreshortened review process for the transition year, it will be difficult to investigate the reasons for such variation as have been seen. Equally, consumers expect that prices will be equitable and will generally track the AER approved revenue allowances. It is not acceptable for such significant inconsistencies to be allowed to continue.

The MEU is aware that TransGrid has released its preliminary views on a new pricing methodology. The MEU expects that the AER will request that TransGrid provide a revised pricing methodology for the transition year implementing a number of the features included in the TransGrid review.

Appendix 1

TransGrid

Consultation Paper on Transmission Pricing

Comments on the Consultation Paper

Submission by

Energy Markets Reform Forum

December 2013

Assistance in preparing this submission by the Energy Markets Reform Forum (EMRF) was provided by Headberry Partners Pty Ltd and Darach Energy Consulting Services

This project was part funded by the Consumer Advocacy Panel (www.advocacypanel.com.au) as part of its grants process for consumer advocacy and research projects for the benefit of consumers of electricity and natural gas.

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Summary

The Energy Markets Reform Forum (EMRF) represents a group of large energy firms in the NSW industrial sector and as such utilize the services provided by TransGrid. The EMRF is an affiliate of Major Energy Users Inc (MEU) which has affiliates operating in SA, NT, WA and Victoria.

The EMRF (and MEU) welcome the opportunity to put its views on TransGrid's pricing methodology. The EMRF sees that the action by TransGrid reflects the overall view that electricity pricing for network services is undergoing significant review as network pricing is seen as not reflecting best practice and delivers inappropriate signals to end users to achieve the most efficient use of network assets.

The EMRF congratulates TransGrid in undertaking this initiative as there are clear signs that its current pricing methodology is not delivering prices that are consistent or cost reflective. The EMRF is aware that many users of TransGrid services are extremely unhappy with the current approach to pricing and the EMRF has attempted to explain in this response why this is the case.

There is an increasing recognition that the burgeoning costs for electricity are being driven by a lack of involvement by the demand side in the electricity market and this is having a major impact on the supply and pricing of network services. The single most important aspect of ensuring network services are efficient is that the prices charged for the services must reflect the costs involved in their provision. Prices that are lower than the cost of the service results in inefficient use of the services and prices that are higher than the cost lead to actions that also result in inefficiency.

It is widely recognised that investment in networks is driven by increasing demand yet too little of network pricing reflects this driver of costs.

For a consumer to invest, the information it has on network costs is based on current prices and an expectation that future prices will follow the allowed changes to the completion of the regulatory period. As many consumers have found to their cost, network prices and charges can and do increase at rates much faster than the allowed rates of change, indicating that network pricing does not follow basic principles which deliver cost reflectivity.

A recent Grattan report "Shock to the system - Dealing with falling electricity demand"[6] highlights a number of major negative aspects that the current network pricing approaches lead to. In particular it reinforces the EMRF view that demand is the major driver of network investment and the use of

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[6] Available at http://grattan.edu.au/publications/reports/post/shock-to-the-system-dealing-with-falling-electricity-demand/

consumption as a device to recover network revenue imposes cross subsidisation and inappropriate signals for use of electricity.

This response by the EMRF is structured to identify areas of general concern about network pricing (section 1), specific concerns with TransGrid's pricing approach (section 2) and responses to the specific questions raised by TransGrid (section 3)

1. Introduction

The Energy Markets Reform Forum (EMRF) welcomes the opportunity to respond to TransGrid's Consultation Paper on Transmission Pricing issued in November 2913 (Consultation Paper).

1.1 About the EMRF

The EMRF is the NSW affiliate of the Major Energy Users Inc (MEU) represents some 20 large energy using companies across the NEM and in Western Australia and the Northern Territory. Member companies of the MEU are drawn from the following industries:

- Iron and steel
- Cement
- Paper, pulp and cardboard
- Manufacturing
- Processed minerals
- Fertilizers and mining explosives
- Tourism and accommodation
- Mining

The EMRF and MEU have members with a major presence in regional centres throughout Australia, e.g. Western Sydney, Newcastle, Gladstone, Port Kembla, Albury/Wodonga, Mount Gambier, Westernport, Geelong, Launceston, Port Pirie, Kwinana and Darwin and therefore have a good understanding of the impacts of transmission costs outside of major centres..

The articles of the EMRF and MEU require a focus on the cost, quality, reliability and sustainability of energy supplies essential for the continuing operations of the members who have invested many billions of dollars to establish and maintain their facilities.

EMRF members have operations in New South Wales and are large users of electricity; they are therefore are exposed to the costs of the service provided by TransGrid. This means that the EMRF members are major contributors to TransGrid revenue and have a great interest in the approach used by TransGrid to set the prices for its services.

1.2 Overview of the arrangements

TransGrid provides the main electricity transmission network in NSW. As the coordinating electricity transmission service provider for the state, TransGrid also passes through to consumers the costs for providing the transmission services provided by others (viz Ausgrid and Directlink), for the planning and operating of the NSW transmission network and interfacing with the transmission networks in Queensland and Victoria.

The Energy Markets Reform Forum (EMRF) is an affiliate of Major Energy Users, Inc. and has already provided its views to the AER on applications for revenue resets by TransGrid in the past and plans to provide its views to the reset planned for 2014. The EMRF has also provided its views on the applications by Ausgrid for revenue resets for its transmission element.

As coordinating TNSP for NSW, TransGrid has to provide a methodology for pricing the provision of the transmission service to consumers and is required to obtain approval of its pricing methodology from the AER. This submission provides the views of the EMRF and MEU on the approach to pricing of electricity transmission services and how these should be structured. In making the following comments, the EMRF is aware that there are some constraints imposed by the electricity rules on how transmission pricing must be developed but considers that what is proposed below generally complies with the pricing rules[7].

1.3 The cost drivers of the network

As TransGrid points out in its Consultation Paper, there have been many reviews on how transmission pricing (indeed all electricity network pricing) should be developed, and it is recognised that there is no perfect solution to how this should be structured. TransGrid points out that the current transmission pricing rules were the focus of an Australian Energy Market Commission (AEMC) review carried out in 2006 and much of the pricing rules developed for electricity distribution were derived form this review.

However, more recent work highlights that cost reflective pricing is essential if efficient demand side responsiveness is to be implemented. As the energy networks are sized to accommodate the peak demand that is expected in the network for the next regulatory period, the bulk of the costs that an NSP incurs in providing the service are directly related to the size of the network and the expected peak demand at each entry and exit point of the network. The importance of this observation is that prices that deliver a high degree of cost reflectivity must therefore be based on the demand placed on the network at times when the network is near its peak capacity. As demand is accepted as the driver of new investment therefore, in the past, demand was also the driver of past investment. That earlier investment is now classified as "sunk" but to recover these sunk costs on any other basis (such as consumption) does not recognise what caused the sunk costs to be incurred originally.

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[7] The principal rule requirements are set out in the National Electricity Rules (NER) Part J and, in particular, Chapters 6A.23 (‘Pricing Principles for Prescribed Transmission Services’) and 6A.24 (‘Pricing Methodology’).

The economic pundits assert that the recovery of the costs relating to "sunk" assets can be carried out on a number of bases which all have "legitimate" credibility - such bases include fixed prices (as used for transmission entry and exit assets), recovery using demand (as used for the locational TUoS assets) or on a consumption basis (as used as an option for non-locational TUoS and common services).

Acceptance of the basic concept (that demand is the driver of both new and was the driver for historic investment) has greater credibility on a theoretical basis as this provides recognition of what was been provided in the past and should be provided in the future. Acceptance of the premise that, as demand drives investment, demand should be the basis for pricing then has repercussions throughout the development of the pricing methodology proposed by an NSP if pricing is to be cost reflective.

Application of TNSP approaches to some aspects of pricing are informative. For example, under the TNSP pricing rules the cost of entry and exit assets is required to be recovered on a fixed time based price (eg $/day). When there are a number of users connected at the same entry and exit point, the fixed charges are shared on a demand basis. This supports the concept that demand is the prime basis for allocation of costs.

A recent Grattan report "Shock to the system - Dealing with falling electricity demand"[8] stresses this same point (pages 14-16):

> "Peak demand defines how much infrastructure - poles, wires, transformers and transmission stations - a network business needs to install. This, in turn, is a major determinant of the amount that a network business must spend, which in turn determines the prices charged to customers.
>
> In each state of the NEM, peak demand levels reached historical high points at some time between 2008-09 and 2010-11, and declined by 2012-13. In Western Australia, peak demand grew until 2011-12, but declined in 2012-13
>
> Figure [3.1] shows how peak demand for the 2012-13 year compares to historical peaks in each state of Australia. The fall in peak demand ranged from three per cent in Western Australia to more than ten per cent in Tasmania.
>
> Analysing peak demand patterns is harder than analysing consumption trends. Peak demand occurs at different times in different locations and this has different implications at different levels of the network.

[8] Available at http://grattan.edu.au/publications/reports/post/shock-to-the-system-dealing-with-falling-electricity-demand/

Figure 3.1: Shortfall in 2012-13 peak demand levels, relative to historical peaks

Source: Grattan Analysis based on AEMO (1998-2013) and IMO (2013)

> The problem with falling peak demand is that it may leave networks with excess capacity. The current value of regulated assets in the NEM and the SWIS is around $86.9 billion. If the fall in peak demand in each state is applied to the value of assets, it suggests that our major power networks may already contain around $4.9 billion in excess assets. These assets are neither wanted nor needed, but they are costing consumers about $444 million a year.

EMRF affiliate, Major Energy Users, raised this issue of the cost of excess capacity being imposed on consumers by proposing a network rule change in late 2011. This rule change sought to ensure the costs for a network were optimised for the actual service provided rather than one which recovers the value of actual assets used, yet the AEMC concluded that the risk for the networks to carry the cost for the excess capacity they provided was too great and therefore not in the interests of consumers. The EMRF considers that the AEMC erred in reaching this conclusion.

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1.4 Observed anomalies in pricing

Despite the basic premise that pricing should be cost reflective, TNSPs apply some intriguing approaches to allocation of prices. For example:

- The current approaches to setting entry and exit prices are based on the costs of the actual plant and equipment provided at the entry/exit, regardless as to whether the assets are oversized or not. As noted in section 1.3 above, the Grattan report points out that redundant assets are an expense that consumers are paying for. EMRF affiliate Major Energy Users sought to address this issue but the AEMC rejected its rule change proposal that assets should be optimised.

However, the EMRF notes that that the rules require entry and exit prices to be set on a $/day basis and reflect the cost of the assets used for providing the service. However, there is no requirement on the NSP to ensure the entry/exit assets are appropriately sized to provide the service. The EMRF considers that the TNSP should be only permitted to recover the costs of assets that optimally provide the service, and that the user should not be required to pay for assets that are not required at entry/exits or are oversized. This would result in entry/exits that are priced cost reflectively.

- Where an end user and a generator share the same entry/exit point, how should costs for the entry/exit be allocated? Under the current approach, the generator is provided with "free" entry for its export capacity, at least up to the contracted demand of the end user. This then identifies two interesting challenges;

    - This cost allocation approach provides the generator with a considerable benefit compared to another generator which has to pay full value for its entry. Effectively the generator is being provided a competitive advantage within a set of rules that is intended to be non-discriminatory
    - When the end user demand falls below the capacity required by the generator for entry, how should the entry/exit charges be allocated?
    - If the entry/exit provides more capacity than is needed by the connecting generator/load, the current arrangements require those connected to pay for the full value of the assets provided. However, at another entry/exit, which is properly sized, the charges will be less for the same service. Who should pay for the unused capacity?
    - Most generators require access to the NEM to provide power for start up prior to generating. This makes them end users for a period of time. Some generators have "black start" capability which requires them to have made a greater investment than equivalent generators without this capability. Yet both pay the same entry charges but the generator without the black start capability does not pay any TUoS or common service charges even though they are using the shared assets just as any other end user. This cost allocation approach requires consumers to pay the TUoS and common service charges to benefit most generators. This provides these generators with a competitive

advantage over those with "black start" capability which don't need to access the NEM for start up purposes.

Put another way, the generator without the ‘black start’ capability needs the NEM to commence its operations. Therefore, in principle, it should pay TUOS, etc for the electricity it uses to start up its generators just as any other load. By not paying TUoS, this gives generators without black start capability a competitive advantage over a generator which has made the investment to provide for black start capability. By not paying for the TUoS it uses, a generator transfers these costs to consumers. Paying locational TUoS provides a locational signal to generators - a signal they do not otherwise get.

Cost reflectivity means that those that benefit should contribute to the provision of the services. To resolve the anomalies identified above (and others) cost reflectivity would require shared entry/exits to have the costs allocated in proportion to the use each applies to the assets, and the costs to be allocated in proportion to demand. Generators without "black start" capability should pay for the use of the assets like any other end user, including TUoS and common service charges.

- Generators are not constrained to locate where they wish[9] or to dispatch themselves as they desire. Generator location and dispatch decisions have a major impact on the locational TUoS an end user pays as the locational TUoS payable reflects the distance an end user is from the locus of the generation in a region. This varies the share of the network costs an end user has yet the end user has no ability to influence the decisions that impact its costs.

  Decisions made to shut down generators are made totally independently of end users. An end user might have made a decision to minimise its locational TUoS by establishing near a generator. If that generator ceases operation then the locational TUoS could change by a significant amount.

  The end user decision processes reflected the locational signals, yet is exposed to increases in costs because of the way the network has priced its services.

- Regional boundaries have a significant impact on end users through the pricing approach of the TNSPs. Although for the vast majority of the time spot prices between regions are aligned, the pricing of network charges across regional boundaries can be very different. For example, in the city Albury/Wodonga, there is a differential of 100% between the NSW and

[9] Other than the impact they might incur from the imposition of the marginal loss factor

Victorian transmission charges. Users on the NSW side pay about twice as much for their transmission system services as users on the Victorian side of the city pay.[10]

1.5 Better cost reflectivity must be an outcome

The EMRF considers that for network pricing to be equitable, it must reflect as closely as possible, the costs involved in providing the service to each exit point in the network. Currently the rules imply[11] that the cost of the service must lie between the avoided cost and the marginal cost and this generally covers a very broad band of transmission pricing options with varying degrees of efficiency, complexity and cost reflectivity.

There are constraints within the transmission rules that reduce the cost reflectivity for service provision and others which enhance it. For example, the decision that overall more than 50% of the costs of the service provision are to be "postage stamped" (ie through non-locational TUoS and common service charges) reduces cost reflectivity of outcomes. The imposition of entry and exit prices to reflect the actual costs of the hardware involved with providing the entry/exit service costs increases cost reflectivity provided that the assets are sized to provide the service required.

Concurrent with the assessments of establishing network pricing methodologies by NSPs, is the decision of the Standing Council on Energy and Resources (SCER) to examine ways of increasing demand side participation in the energy markets as a tool to reduce the burgeoning network costs involved with the transport of electricity and gas. To this end, SCER sought advice from AEMC on ways of improving demand side participation and AEMC provided a report (Power of Choice) complete with many recommendations and rule change proposals to increase consumer involvement in the energy markets.

One of the most important aspects of the AEMC report is that efficient demand side participation will be increased by providing prices for network services that are as close as possible (given the constraints in the rules) to cost reflective prices. This means that accepting cost reflectivity as only having to lie in a broad band between avoided cost and marginal cost is no longer sufficient.

1.6 Costs must be shared equitably

TransGrid pricing is different to other approaches used by other TNSPs in the NEM. Although TransGrid, like all other TNSPs other than AEMO in Victoria, averages the usage in every half hour of the year to develop its prices, it

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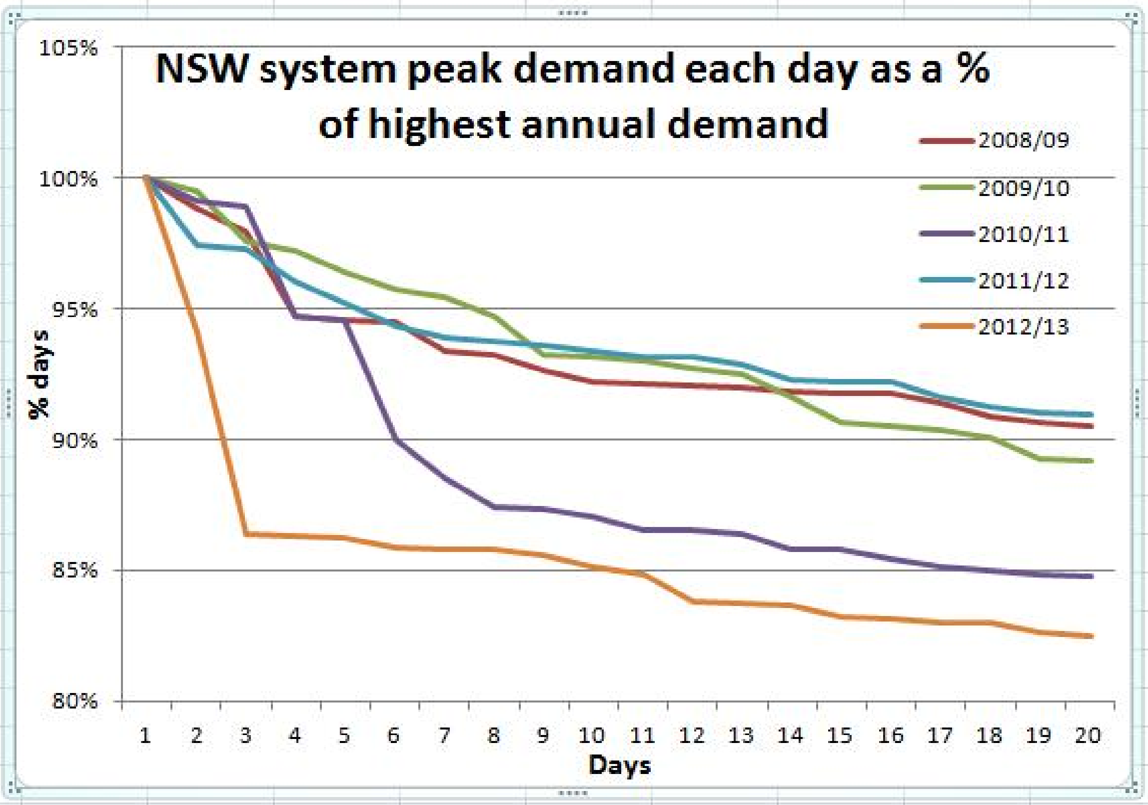
[10] Similar differentials can apply between adjacent distribution regions as well, highlighting the need to address the issue widely.

[11] Although not stipulated, the implication of the prudent discount allowed for transmission is that a prudent discount can be applied if the price exceeds the stand alone cost (ie a bypass) and a prudent discount should not allow a price of less than the avoided (marginal) cost for the service provision.

recovers the monthly locational TUoS on the basis of the highest demand incurred in the month. In contrast most other TNSPs recover the locational TUoS based on the contracted demand or the highest demand incurred in the previous 12 months.

As a point of marked difference to other TNSPs including TransGrid, AEMO assesses the flows on the network by consumers on the 10 days in a year when the network is most heavily used in order to develop its prices. The EMRF sees that this approach is more cost reflective in that those consumers that use the network occasionally but cause the size of the network to be increased through their usage at high demand times should incur the costs that their occasional use causes. In other words, consumers pay according to their contribution to the co-incident peak demand (for 10 peak days) at each transmission connection point rather than their individual peak demand.

The following chart shows the electricity peak system demand on the highest 20 demand days in the last 5 years in NSW. For the sake of comparison, the lowest daily peak demand over these same 5 years averages some 56% of the peaks recorded in each year, and the average demand across all half hour periods is about 62% of the peak demand recorded in each year, and trending down, implying there is a reducing system capacity factor at the same time reduced consumption and demand is being seen.



Source: AEMO data

The chart[12] shows that 10th highest peak demand in any year averages about 10% below the peak recorded in the year, and the 20th highest peak demand in any year is up to 15% below the highest peak recorded in the year. This shows that demand in NSW is reasonably peaky and that large demands are made on the network for a very few days in the year. What is just as important is that the trend towards increasing peakiness is increasing over time.

Many of those consumers using electricity on these peak system days do not use the network anywhere near to the same extent during the rest of the year. But this high demand imposes significantly greater cost for the provision of the network. By allocating the usage of the network based on demand on the 10 peak demand days of the year means that all those connected at a transmission connection point on these days are allocated their appropriate share of the costs (ie those using the network on these days cause the network to be sized as it is and, therefore, pay their share of the costs that cause the network to be sized as it is).

The benefit of the AEMO approach is that assessing usage on the peak system days emphasises the impact occasional very high demands can have on the network, particularly when these occur on peak days at the connection point. This point has been emphasized in the recently released report "NSW Energy Efficiency Action Plan" released by the NSW Office of Environment and Heritage. In this report the Department states (page 11)

> "The key driver behind rising electricity costs has been to meet demand at peak times and locations. Energy efficiency policy can maximise benefits if it encourages investment in technologies and services that save energy during peak times in the most congested areas of the electricity grid."

Most TNSPs, including TransGrid, assess the network usage for all times of the year which leads to an average usage outcome rather than emphasising the occasional high demands imposed on the network. The average demand on the NSW network is just over 60% of the peak demand recorded in each of the last 5 years so using the averaging allocation approach rather than the AEMO approach would impose greater costs on those consumers which have constant demands and advantage those consumers that only use the network occasionally, but have high demands in the peak periods, thereby forcing the network to be oversized for most of the time.

The EMRF considers that the AEMO approach to allocating usage (and therefore setting prices) based on the peak usage times of the year, provides two very important advantages:

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[12] The data for year 2011/12 is heavily influenced by an abnormally low peak demand recorded in 2011/12 which is nearly 10% below the average peak demands recoded over all five years.

1. The cost allocation reflects the usage made by all consumers in proportion to the demand they make on the network on the peak days, recognising the network is sized to meet the occasional peak demand.

2. Pricing based on occasional peak usage sends a signal to those consumers of the costs that their actual peak demand causes. This allows those users to either pay a premium for the costs they impose, or to moderate their demand so that the network is not sized for occasional usage.

The EMRF sees that the AEMO approach to pricing network services should be encouraged and is therefore supported by EMRF.

1.7 Financial data from year t-2 is out of date

TransGrid uses historical data for development of its prices which is many months out of date. This is because that TransGrid proposes to use data recorded in full financial years yet by the time that TransGrid would be calculating prices the historic data is many months (even years) out of date.

The EMRF considers that as a minimum, TransGrid must use 12 month data that is the most up to date possible for the development of prices. For example, if TransGrid were calculating prices for the coming year in April of the year, than it should use data recorded in the 12 months to the end of March. This data is available.

1.8 Inclusion of known significant changes

The EMRF accepts that forecasting is challenging, especially when it has been observed that forecast of demand are proving to be quite optimistic with forecasts consistently exceeding actual demands and in some cases where actual demand is lower than actual demands in previous years.

The EMRF considers that recent historical data is an acceptable surrogate for setting prices, provided that the data is adjusted for known significant changes in demand such as from forecast closures of load and generation and forecast new loads and generation being introduced.

The EMRF therefore considers the approach to setting prices should allow some flexibility to incorporate known changes; for example, if there is decommissioning of significant loads or highly variable load, then TransGrid should moderate the historical data with forecasts of changes. However, it is noted that:

1. This process would need to be initiated by connection customers; and

2. TransGrid would only use this flexibility under 'exceptional circumstances'.

It is most important therefore that customers are involved in moderating the historical data and that TransGrid clearly define the circumstances in which it moderates the data.

More generally, in the absence of a reconciliation process, the use of historical data for locational charges is likely to create winners and losers relative to the current situation, and it is important that these outcomes are better understood and consumers provided with adequate notice of the potential impacts.

The market in which TransGrid operates is one which protects the network owner from errors it makes. Regardless of any mistake made (especially one where an unnecessary investment is made) TransGrid still receives the allowed revenue to be acquired. In contrast the loss of customer in a competitive market results in loss of revenue for the provider whereas TransGrid is allowed to recover this lost revenue from other customers by increasing its prices.

1.9 Allocation of costs

For transmission, the rules require that costs be allocated to five centres - entry, exit, common service, locational TUoS and non-locational TUoS (also called "general service").

Despite there being some constraints imposed by the rules on how costs are to be allocated there is inconsistency between NSPs as to what is exactly included in each category. This occurs because each NSP has the freedom to allocate costs under the Rules.

The allocation of costs to entry and exit should be straight forward and include only those costs associated with the dedicated assets needed to service the generators or loads. Even though there is apparent clarity in what are to be allocated to entry and exits, the EMRF and its affiliates have noted there is some inconsistency in allocation between different TNSPs in different regions.

In a similar way, the EMRF and its affiliates have seen that allocation of common services vary between TNSPs in different regions. The EMRF is concerned that too many costs are being included in the common service "bucket" of costs. At its simplest, common services should only include those costs that cannot be readily allocated to transmission services (TUoS). The rules attempt to provide some cost reflectivity in pricing by having prices for locational TUoS vary with the value of the assets needed to transport electricity to each exit point. If allocation of costs to common services is overstated, it results in the locational TUoS being understated and this reduces the value of the price signalling that is provided by having locational TUoS.

Similarly, the allocation of overheads varies between NSPs and across different regions. The EMRF members and members of its affiliates have varying approaches to allocation of these costs, so it is accepted as reasonable that there will also be variance between NSPs. However, EMRF members highlight that current business practice trend is to maximise the costs incurred at "the workface" and minimise the overhead costs. If the TNSPs complied with this current business trend, it would minimise the costs that would be classified as common services and maximise the operating costs of entry, exit, locational TUoS and non-locational TUoS prices.

The EMRF considers the AER needs to define exactly what assets and costs are to be included in each element of cost - entry, exit, and common services. The current guideline on cost allocation provides considerable flexibility to NSPs to allocate their costs to each of these, so the EMRF considers that the cost allocation guidelines should be more specific as to what costs are to be allocated to which element.

In this regard, the EMRF notes that the opex used by NSPs is usually allocated as a common service on the basis that the amount of opex varies from location to location during a regulatory period and is therefore not specific to any element of the network. The EMRF does not agree with this simplistic assessment.

The cost allocation for *assets* is based on using the replacement cost for all physical assets. That is, rather than using the depreciated value of assets for cost allocation, at each location, the pricing is developed so that customers are not provided reducing costs during the life of the assets and then with a large charge when the assets are replaced; the amount of depreciation is recovered across the entire asset base and included in the TUoS element. The EMRF agrees that this approach is sensible.

But this approach should be extended to large amounts of the opex as the bulk of the opex is allocated to maintenance of power lines and substations, as well as to the finance raising costs for the assets. Applying these costs to the TUoS reflects reality and would follow the same approach used to allocate depreciation.

Reducing the common service element and adding costs to TUoS provides greater cost reflectivity and locational signalling.

The rules then define that the balance of the costs are TUoS costs, the revenues for which are to be allocated 50 per cent on a locational basis and 50 per cent on a postage stamp.

Clarifying the definitions of costs and where they are to be allocated to generate the most cost reflective outcome would also assist TransGrid in this current assessment for its pricing methodology.

1.10 Pricing approach

The rules require the recovery of entry and exit costs to be based on a fixed charge per day (ie $/day) and for locational TUoS to be recovered on the basis of peak demand (ie $/MW). Each NSP is permitted to recover non-locational TUoS and common service based on any of demand (MW), consumption MWh) or a mix of both providing that the cost is "postage stamped".

All NSPs recover their non-locational TUoS and common service by allowing consumers to select which option delivers the lower cost. The NSPs advise that the setting of the prices for these two charges are set on the basis that the "average user" would be indifferent to which charge was applied. The EMRF finds that this flexibility does not result in cost reflectivity. In fact, it embeds a bias against cost reflectivity.

For example, the average annual capacity factor of the NSW network is about 60 per cent (ie the average demand in a year is about 60 per cent of the maximum demand recorded in the same year). If a user has a capacity factor of 60% then it is indifferent to whether it pays its non-locational TUoS and common service charges in terms of demand or consumption. If a user has a capacity factor of less than 60 per cent it is incentivised to pay these charges on a consumption basis whereas a user with a higher capacity factor than 60 per cent is incentivised to pay the charges based on its demand.

If two users both have a demand of 10 MW, both impose the same cost to develop the network to provide the service they require. If one has a capacity factor of more than 80 per cent (typical of most flat load users) and the other has a capacity factor of less than 35 per cent (typical of a user sensitive to ambient temperatures), then the low capacity factor user is not paying for the costs it imposes on the network and the high capacity user is subsidising the low capacity user. There should be no requirement for one consumer to cross subsidise another, yet allowing the NSPs the ability to decide on how the charges are to be recovered, embeds cross subsidisation under the TransGrid approach and in other jurisdictions.

The issue goes deeper. Because the high capacity user is paying more for its service it is incentivised to seek alternatives to using the network and is likely to expend capital to reduce its unnecessarily high charges. Because of this the investment is inefficient. In contrast, the low capacity user is paying less for its service than the costs it imposes on the network and is not incentivised to address its usage. The Power of Choice program initiated by SCER, developed by the AEMC and to be implemented under the aegis of the AER, is about incentivising more efficient utilisation of networks.

The Grattan report referenced in section 1.3 also addresses the issue of how the approach to pricing introduces cross subsidies. On page 17, Grattan comments:

> "The spending on assets of distribution and transmission businesses is closely tied to the level of peak demand in the network. Yet most customers are not charged a tariff that reflects how much they contribute to the network's peak demand level.
>
> For many years some large commercial and industrial customers have paid a significant portion of their bills based on their peak use, to account for the large load they put on the network.
>
> Residential customers' bills, however, are almost entirely charged at a variable rate. That is, customers pay a set price per kilowatt hour of electricity they use throughout the year. The bill is calculated by multiplying this price by the customers' total electricity consumption.
>
> So while the cost of the network is driven by peak demand, consumers' share of the cost is based on consumption. Therefore they have little incentive to use less power at peak times, which would help networks manage costs."

As a basic premise, the pricing rules seek to maximise cost reflectivity because this is recognised to provide the most efficient use of all resources, as the Power of Choice program highlights. Under the building block approach to network regulation, NSPs have an inbuilt incentive to find network solutions to address the needs of consumers[13].

The approach taken by TransGrid to recover non-locational TUoS and common service charges using the current practice of imposing the lower of the charges calculated from demand or consumption propagates self interest of those paying yet does not result in equity.

1.11 Use of the network as a standby

If network pricing is structured on a cost reflective basis at times of greatest use of the network, a number of consumers could economically provide their own generation and by doing so significantly increase the efficiency of both the energy market and nationally by increasing efficiency of energy conversion by more efficient generation, reducing losses and reducing the need for network investments.

[13] This is because network solutions provide a return on the investments made by NSPs through the rate of return allowed. The costs of non network solutions are a cost which is included in opex which does not include a profit element.

If a consumer reduces its demand (fully or partially) during times of peak demand, then the efficiency of the network improves over time because the network no longer needs to be sized for the occasional peak demand and less augmentation of the network is required.

Certainty of not having to use the network at all requires a self generator to install its own backup as single unit generators do have to come off-line for maintenance and the occasional breakdown. Typically a self generator expects that a single unit will be off-line for 5-7 per cent of the time, with most of this time being scheduled.

From a self generator's view, having to duplicate its own generation prevents most self generation options occurring due to cost. Self generation can be made more viable when the network provides a back up to the self generator, yet current pricing options impose on a user of the network the same charge regardless of whether the usage is made when the network has spare capacity or at peak demand times.

A self generator can operate in such a way that it is not using the network on peak demand days. As most peak demand days are on very hot or very cold weekday days, the self generator can schedule its maintenance so that it avoids having to use the network backup on the times most likely to be on the 10 peak demand days in the year and schedule their need for backup at times when lower network demands are most likely.

Under the current pricing and charging approaches used by most TNSPs, a self generator will have to pay for network usage as if it were a consistent user, even if the time of the usage is when there is considerable spare capacity in the network.

As it is recognised that demand side participation is being encouraged (and self generation is the ultimate demand side response) the provision of low cost network services to provide a backup should be encouraged[14] and the network services priced to achieve this outcome.

ElectraNet in South Australia provides pricing of the network when the network provides this standby role. In its most recent pricing methodology[15], ElectraNet states:

> **"6.12 Standby service arrangements**

[14] Noting that backup should only be provided during periods of low utilisation of the network. If standby is provided at peak usage times, then the value of the demand side response has little value to the network.
[15] ElectraNet Proposed Pricing Methodology 1 July 2013 to 30 June 2018 May 2012 Version 2.0 was approved by the AER as part of the AER revenue reset review in 2013

This provision addresses the situation where ElectraNet has agreed to provide *prescribed transmission services* on a standby basis (such as to cover the *outage* of onsite *generation*).

If ElectraNet agrees to provide a standby service the customer's *connection agreement* must specify the terms and conditions applying to the provision of this service.

The customer's *connection agreement* would be required to specify the contract agreed maximum demand required to be available to the customer under normal operating conditions and a greater demand that may be sought on a standby basis subject to the operational condition of the *transmission network* at the time the standby arrangements are to be called on. The *transmission network* would be planned and developed to satisfy the contract agreed maximum demand rather than the standby demand.

The conditions to temporally vary from the contract agreed maximum demand must be specified in the customer's *connection agreement* and must ensure that compliance with the South Australian Electricity Transmission Code is maintained.

In this instance the customer will pay *prescribed exit services* charges (if applicable), *prescribed TUOS services* – locational component charges, *prescribed TUOS services*– non-locational component charges and *prescribed common transmission services* based:

- on the contract agreed maximum demand under normal operating conditions; and
- the standby demand and/or actual *energy* consumption during times that the standby service is actually utilised for *energy* delivery to the customer.

For the avoidance of doubt:

- where a standby service arrangement has been agreed between ElectraNet and the relevant customer, the customer's *connection agreement* must specify (amongst other things) a contract agreed maximum demand and the conditions under which an excess demand charge as detailed in section 6.13 will apply;
- where a customer's forecast agreed maximum demand results in the need to augment the transmission network access to the standby service arrangements may be withdrawn; and
- nothing in this section 6.12 obliges ElectraNet to agree to provide a standby service arrangement requested by a customer."

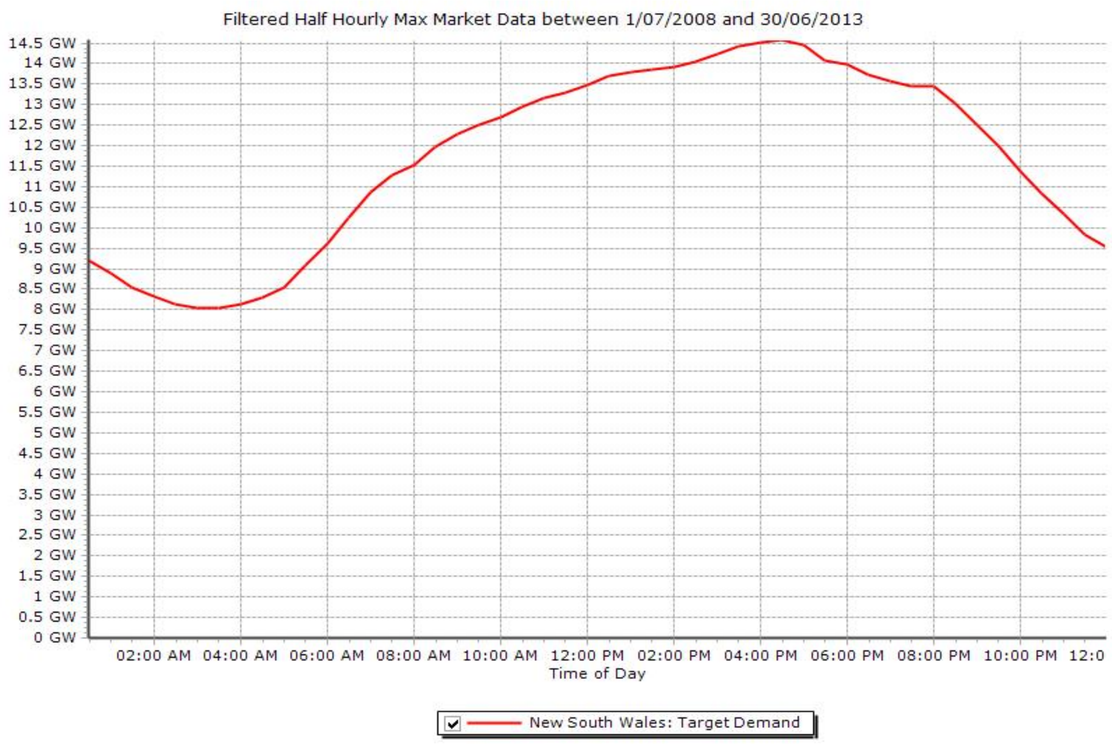
On this basis the EMRF supports the AEMO approach to pricing its network services and considers that charging for services should be made on the basis of usage only at peak usage times. This means that those causing the network to be sized to serve the peak demands would be exposed to the costs they impose. Those using the standby service would only be permitted to use the network when there was spare capacity available.

Further, the EMRF generally supports the ElectraNet approach to the provision of network standby services.

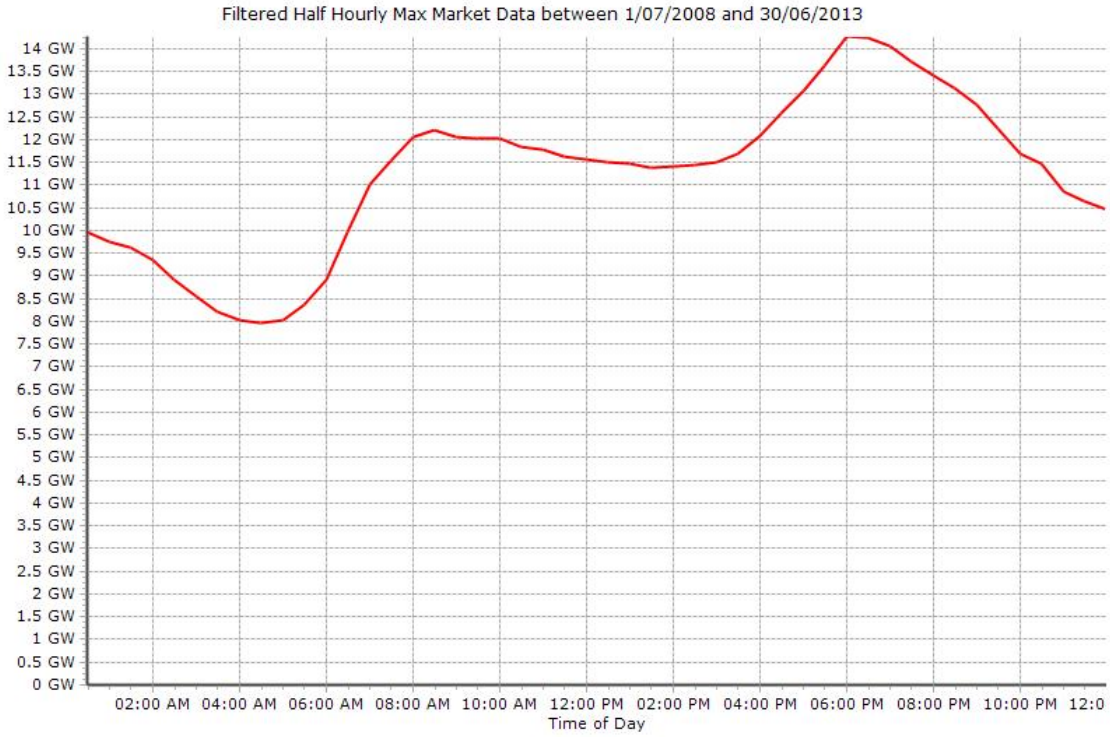
1.12 Time of use pricing

It is well recognised that the highest network usage occurs on very hot or very cold days. Within these days, the peak demand typically occurs in NSW on working days between the hours of 2 pm and 8 pm.

This can be seen in the following two charts which show the average peak demand in NSW across the time of day for the last five financial years. The first chart reflects the maximum peak demands experienced in the warmer months (January, February, March, October, November and December) and the second chart the maximum peak demands in the cooler months (April, May, June, July August and September)



Source: AEMO data



Source: AEMO data

To increase the capacity factor of the network (ie use the assets more efficiently) pricing signals need to be provided to reduce demand during this key time of the day.

Typically prices are set to address peak/shoulder times which are between 7 am to 10 pm week days. In practice this wide time period does not address when the networks are most loaded.

AEMO sets its prices on network usage on the 10 peak days in the year for demands occurring in the mid afternoon to early evening reflecting the demand trends seen in the above charts. It then applies these prices to the actual or contract demands to develop the end user charges.

The AEMO approach only goes half way to providing signals to reduce demand at the critical times. It would deliver more cost reflective outcomes if the prices were set on the peak time of day (as they do) but then also developed the charges to reflect the demand placed by each end user at this critical time of day.

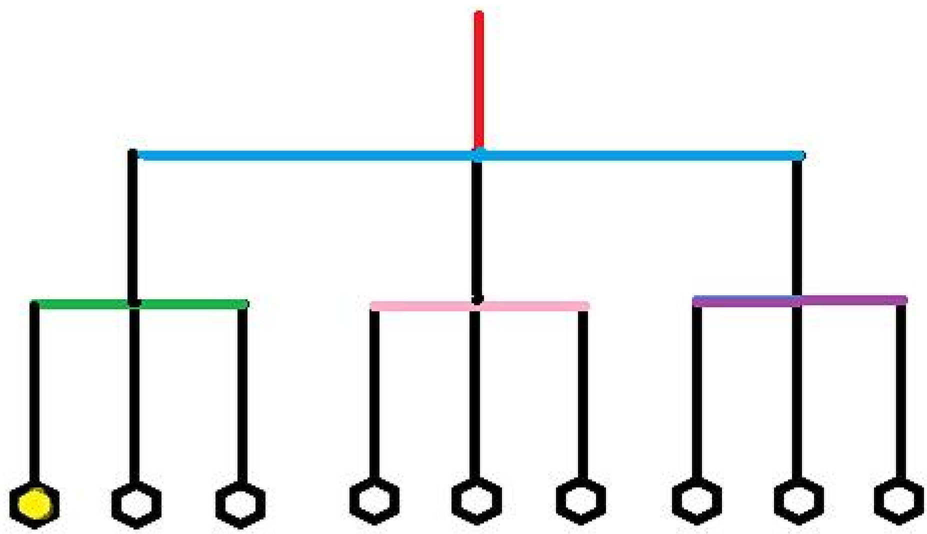
Charges calculated on usage during the times of the day of peak demand (rather than usage across the whole day) would provide a clear signal to end users to reduce their usage at times when the network is most likely to be heavily loaded.

1.13 Coincidence of DSR projects and timing

Currently benefits of load reductions are only provided when there is the potential of network augmentation. Demand side projects are usually modest in size and individually unlikely to deliver significant network benefits and to achieve a network benefit will require a number of DSR projects. Further, load reductions now will have a benefit in the future.

Network benefits do not incentivise widespread demand side responses that might be available but only those where a specific benefit might be applied[16].

There would be a widespread benefit should many small demand side responses be incentivised over a period of time. For example, supposing there are a number of small demand side projects that could proceed if they received a network benefit.



If just one project (the yellow project) proceeds, there could be little benefit to the network, but supposing there are three projects connected to the green network that could proceed, it is possible that the three projects combined might provide a benefit to the green network. Even if there is no benefit to the green network, supposing another six projects proceed but each providing little benefit to their associated networks (the pink and the purple networks) the nine projects combined might provide a benefit to the red network. However the red network will get no benefit because each project is assessed individually. If they had been assessed as a group, then the benefit would have been identified.

[16] This benefit is further reduced by the current approach used by networks where if a user provides a demand side response but needs back up for a short period of time scheduled at low demand times, then there is no benefit provided. This point is exemplified in section 1.11 above.

This example shows that the current approach of assessing projects individually does little, and there would be no benefit identified to the red network because there was no attempt to assess the projects as a group. Providing a benefit to the yellow project would start the process of aggregation of benefits from other sources, each of which provides little benefit in its own right. Once one project is able to be implemented, others would follow. Essentially, the current approach presents a "Catch 22[17]" situation. Without providing a benefit to the first project, the overall benefit which could be achieved will never happen.

As a number of small projects will not occur coincidently but are more likely to occur over time, a recognition of a benefit now as each project is implemented is needed to achieve a benefit at a later time. This means that individual DSR projects must be incentivised as they are implemented assuming that others will follow[18] rather than assessing each individually. A DSR project implemented in 2014 might not deliver a benefit until another DSR project is implemented in 2016, yet the 2016 project might not provide a benefit in the absence of the 2014 project but by 2016, the 2014 project might no longer be possible because of other actions taken in 2014.

To put this issue more succinctly, pricing needs to provide rewards now for "better end user behaviour" recognising that the benefits will accrue in the future. As the assets provided now meet the current needs, the real benefit from multiple demand side responses will occur in the future when augmentations are avoided and the load factor of the network has increased delivering benefits to all consumers.

In contrast, current pricing approaches only provide a reward if the network benefit is immediately deliverable.

[17] A Catch 22 situation is a situation in which a desired outcome or solution is impossible to attain because of a set of inherently illogical rules or conditions.(The Free Dictionary)

[18] Currently DSP projects are assessed individually and on this basis they seldom provide a benefit. Yet if a number were implemented concurrently, there would be a benefit and multiple DSP projects are what is sought.

2. The TransGrid Consultation Paper

The TransGrid Consultation Paper makes reference to the current rule change proposals made by the Standing Council on Energy and Resources (SCER) to improve the cost reflectivity of distribution prices. TransGrid recognises that it needs to take cognisance of these actions by SCER is not only do transmission prices impact on distribution pricing, transmission needs to ensure that its pricing should also be cost reflective. The EMRF supports this action by TransGrid.

TransGrid notes that 8 per cent of the average consumer's electricity costs are from transmission charges. Whilst the EMRF accepts this is typical of small consumers of electricity, the proportion is much greater for large users (such as EMRF members) as its members are connected either directly to TransGrid or to sub-transmission services provided by distribution networks. Because of this, the EMRF is particularly keen for TransGrid to address its pricing approach to achieve similar outcomes to that sought by the SCER rule change proposal.

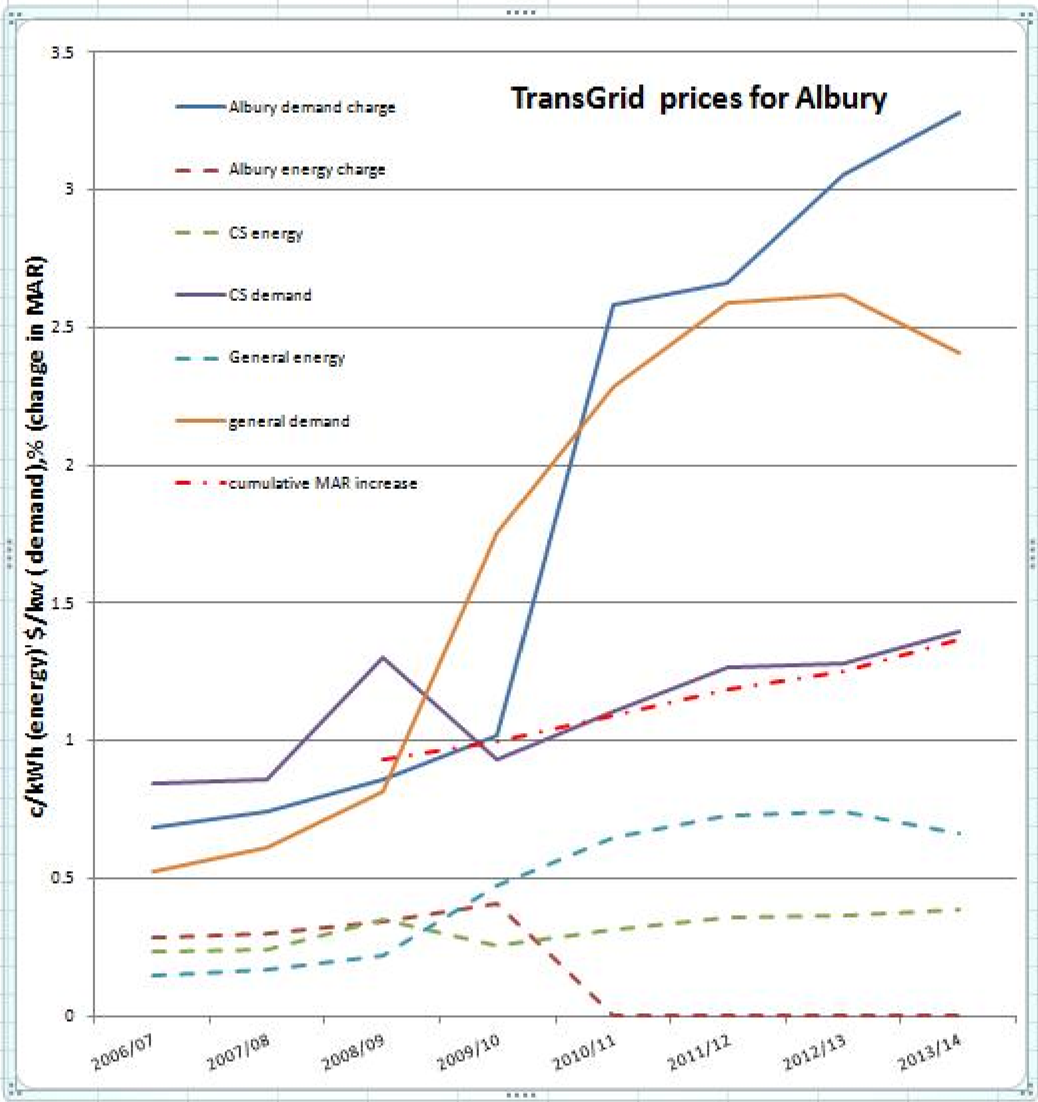
2.1 TransGrid's focus on cost reflective network pricing so far.

TransGrid notes that it needs to address its pricing to achieve two main objectives - to recover the revenue allowed by the regulator and to provide efficient signals for use and investment in the transmission network. The EMRF considers that TransGrid has, in the past, focused on the first part - that of recovering its allowed revenue and has not considered the impact of pricing on consumers. The following two charts demonstrate this point.

The first chart reflects the changes in TransGrid prices at Albury over the past eight years. However, the trends are typical for other locations.

In reading the chart, it is important to note that in 2009/10 TransGrid was required to change its pricing for locational TUoS from a mix of demand and energy to demand only - this change was required for TransGrid to comply with the transmission pricing rules which allow locational TUoS to be recovered only from demand.

The second chart shows what did happen with TransGrid pricing to reflect this change and what should have happened if TransGrid had merely recovered all its revenue from demand.



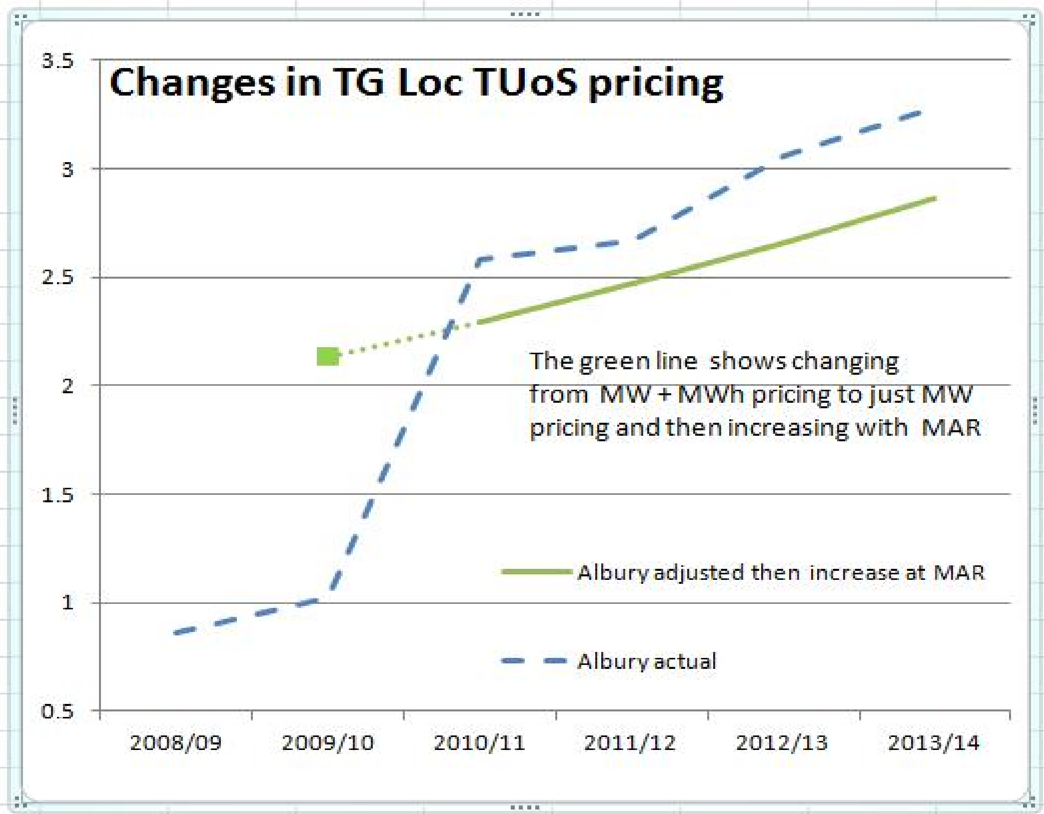
Source: TransGrid published transmission prices published annually

The first chart highlights a number of anomalies in the changes in prices:

- The MAR requirement increases linearly as allowed for by the AER at about 8.7 per cent per annum (% pa).
- In contrast, after the new revenue was set:
  - the non-locational TUoS demand price increases at about 17% pa;
  - the non-locational TUoS energy price increases at about 4.5% pa;
  - the common service demand price increases at about 9% pa; and
  - the common service energy price increases at about 3% pa
- The change for the locational TUoS from a mix of energy and demand shows that the demand price shows a step increase when the locational TUoS energy charge is eliminated in 2009/10. However after the step

change, the locational TUoS then increases approximately at an annual rate of a further 20% pa, well above the allowed rate of increase for the maximum allowed revenue.

The second chart addresses only the locational TUoS price and the change from a mix of demand and energy pricing to just demand pricing.



Source: TransGrid published transmission prices published annually

The chart shows that if TransGrid was just converting demand+energy pricing to demand pricing only, the demand only price should have been set at the green square. Increasing the demand price at the same rate as the MAR, the price would have tracked the green line. Actually, the price increased at nearly twice the rate expected.

The EMRF accepts that over time, the NSW demand did not increase as expected and actually showed small reductions over time. At the same time energy usage declined considerably. Based on this it would be expected that demand based prices would have increased marginally more than the MAR allowed increase in attempting to recover the same amount of revenue over a slightly declining base. In contrast, as the energy used declined by a much greater amount than demand, it would be expected that revenue from energy based prices would have shown significant increases, yet the reverse applied - demand based prices increased very significantly, yet energy based prices fell.

The clear out-take of this is that TransGrid made massive changes to penalise users of electricity who pay their charges based on demand yet those users who pay their general (non-locational TUoS) and common service charges based on energy were provided with a considerable benefit compared to those users paying for the general and common service based on demand.

The EMRF considers that recent pricing by TransGrid has failed to pass the "cost reflective pricing" test and that the proposed consultation is long over due.

2.2 Pricing approaches

TransGrid highlights that network pricing should reflect the marginal cost - ie the cost to provide for the next unit of service. The EMRF agrees that this concept is the basis of any economic assessment. However, in a transmission network with such high reliability as seen in the TransGrid network coupled with declining demand and significant reductions in energy flows, the concept of a marginal cost approach to setting prices loses relevance.

What then becomes the critical aspect is how to price the services to ensure that there is equity between all users and that there is appropriate price signals to ensure that the service is provided at prices that are lower than alternative options, such as bypass or removal from the network. Both bypass and removal from the network results in fewer users paying for the network service, increasing prices to all.

TransGrid posits that (page 9)

> "…new users should face the marginal costs of their locational decisions. On the other hand, it is arguable that existing users do not have any property rights in relation to the existing capacity of the transmission network, and therefore it is appropriate for new and existing users to face exactly the same charges."

The EMRF accepts that all users should pay the same price for the same service regardless when they connected to the network. This becomes even more important in the current time when demand and energy flows are declining. New users connecting now would not impose augmentation costs and therefore their marginal cost would be zero under a marginal cost approach. By treating all users the same, new users will cause a reduction in prices for all existing users. This outcome underpins the concept of price cap regulation which incentivises greater utilisation of the network capacity, resulting in reduced costs for those already connected.

The Consultation Paper describes a number of differing pricing principles - NECA (1999), AEMC Pricing rules (2006) and NZ Electricity Authority (2012). The current pricing rules do not impose any constraint on TNSPs other than to provide approaches (CRNP or modified CRNP)[19] for providing a methodology to set locational TUoS prices.

Because the current pricing rules do not impose the pricing principles discussed by TransGrid, TransGrid has the flexibility to use any or all of these pricing principles providing they do not contravene the current rules.

Summarising the key elements of the three different approaches but remaining within the current rules, there appears to be a common theme that prices should:

1. Reflect the level of spare capacity (effectively this is addressed by the modified CRNP approach included in the current rules as an acceptable approach). This approach would also provide pricing that reflects the expectation of new investment required in the near future

2. Reflect the imposition for investment (past and future) each user imposes on the network. This means that the pricing must be equitable as each consumer must pay for the investment each has required of the network in order to deliver the service.

3. Be efficient; ie prices that result in a cost less than the stand alone cost for the service and prevent a user bypassing the network but exceed the costs a TNSP would avoid if the user ceased to be connected.

4. There is a thread running through the principles that those benefiting and those causing the need for the network to be sized as it is should pay for the cost of the service provided, but what is missing is a statement that the driver of the costs should be the basis on which prices should be set.

Currently the rules state that:

- Entry/exit prices are to reflect the total costs of the assets used to provide the service and these are to be recovered on a cost/day basis.
- Locational TUoS is to be costed at 50 per cent of the value of the assets used to provide the service (although slightly less than 50 per cent can be applied if the **TNSP elects**[20] to use the modified CRNP approach) and the price must be based on the demand incurred at the exit point "…at times of greatest utilisation of the … network…' ie $/MW.
- Non - locational TUoS and common services are to be priced on a postage stamp basis. Implied in this statement is that the TNSP can select the actual unit on which the price is set.

[19] See Transmission pricing rules for definitions of CRNP (cost reflective network pricing) modified CRNP
[20] Note this is a TNSP decision, not one of the consumers who pay for the service TransGrid has elected to use the CRNP approach.

2.3 TransGrid pricing approach

TransGrid generally prices its services in compliance with the current rules. The single exception is that it prices its locational TUoS on assessments made of utilisation for every half hour of the year. The rules stipulate that the allocation of costs has to occur based on the demands incurred at times of greatest utilisation of the network. The importance of this rule requirement is that occasional users of the network, who cause the network to be the size it is, should be allocated their share of the costs.

Whilst the TransGrid approach meets the letter of the rule in that its locational TUoS price development does assess demand at times when there is greatest utilisation of the network, it also reflects utilisation at all other times. In contrast, in Victoria AEMO assesses demand only on the 10 days in the year when utilisation of at each point of supply is at its highest. The EMRF considers that TransGrid should use the AEMO approach.

Again, TransGrid complies with the requirement that non-locational TUoS (general service) and common services are priced on a postage stamp basis, TransGrid has elected to price these services based on the lower charge that results from either using a demand based price ($/MW) and a consumption based price ($/MWh).

This raises the question as to whether TransGrid has complied charging for general and common services on the basis that the price should comply with the principle that the price should be related to the driver of the cost of the assets needed to provide the service.

TransGrid has argued that recovery of the cost of sunk assets can be priced using any driver - number of days, demand, consumption or any other driver that it considers is appropriate - and the current rules allow TransGrid the power to select whatever it considers is acceptable.

Economists argue that once an asset is "sunk" then recovery of costs can be efficiently recovered through many options for pricing. The EMRF disagrees. If an asset was provided in the past to provide for the demand expected in the network, then clearly demand was the driver for the provision of the augmentation of the network *at that time*. Just because the asset is now "sunk" does not change the fact that it was installed to meet the demand expected at the time. In fact, the rules clearly imply that efficient investment must reflect the needs of consumers.

The current TransGrid network operates to serve the peak demand and as a result, it more than caters for the average demand that is some 60 per cent below the peak demand. Average demand reflects the volume of electricity transported (consumption) so pricing network services on the basis of consumption would not reflect the driver for the investments made.

TransGrid allows consumers to pay for general and common services based on the pricing that delivers the lower charge to the consumer. This approach is not equitable (see the discussion in section 1.10 above) and therefore does not comply with the principle of equity. The EMRF considers that demand has driven the provision of the bulk of the assets provided and therefore allocation of costs and recovery of revenue should be based on demand.

2.4 Common services

Of the cost elements that lead to the revenue requirement, allocating costs to common services is again the province of the TNSPs.

The rules (glossary) describe common services as:

> "*Prescribed transmission services* that provide equivalent benefits to all *Transmission Customers* who have a *connection point* with the relevant *transmission network* without any differentiation based on their location within the *transmission system*."

TransGrid has commented in its paper that common services would include (page 15) equipment:

> "…such as voltage support through the use of Static VAr Compensators, which irrespective of their location, provide services to all of the interconnected network."

The EMRF considers that this is not necessarily so. In fact, static VAr compensators located in the far south of the network would not provide a service to consumers in the north.

Similarly, TransGrid includes the cost of network support as a common service as part of opex yet network support provides a service in a specific location of the network and is really an alternative form of network assets.

TransGrid also appears to include the costs of the Ausgrid transmission assets and of Directlink as common services. Consumers in the south of the network get no benefit from either of these transmission assets, yet their cost is smeared over all transmission network users.

As the EMRF notes in section 1.9 above, opex is classified as a common service, yet much of this cost is specific to the maintenance of the assets providing the service. Just as return on and return of investments is allocated to TUoS, so can a large proportion of the opex costs be similarly allocated to TUoS. The EMRF accepts that the network control centre and its staff is probably a cost that cannot be allocated to a specific location and nor could many of the head office functions[21].

The EMRF considers that TransGrid needs to move costs currently included as common services into TUoS to increase cost reflectivity. This point is made in section 1.9 above

2.5 Locational TUoS

TransGrid is permitted to use one of two approaches to setting locational TUoS - CRNP and modified CRNP. Although TransGrid notes the rules require (page 16)

> "... the ***locational*** component must be based on demand at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated."

However, despite this requirement, TransGrid assesses the usage in each element of the transmission network over the entire year and this point is noted in section 1.6 above. The EMRF is not convinced that the TransGrid approach complies with the intent of the rules although the apparent acceptance of the approach by the AER might imply that it meets with the requirements of the rules.

As noted in section 1.6, the EMRF considers that the AEMO approach is more likely to reflect the usage made of the network when most users are accessing the services and therefore result in better cost reflectivity of prices.

2.6 Non-locational TUoS and Common services

As noted in sections 1.3, 1.6 and 1.10 above, the EMRF considers that it is not cost reflective to allow consumers to be charged on the lower of demand or consumption as this results in some consumers paying less for the service they receive than they cost.

The EMRF considers that allocating costs based on demand only will result in greater cost reflectivity than the current approach used by TransGrid.

2.7 CRNP methodology

TransGrid notes (page 17) that the current rules require the TUoS pricing approach to allocate 50% to locational TUoS calculated on a cost reflective basis and the balance to be postage stamped. It poses the question as to

[21] Although as noted in section 1.9, good business practice is for head office functions to be limited with the costs driven down to locational activities.

whether this provides adequate price signals to reasonably equate to long run marginal costs. It goes onto observe that the CRNP process can be modified to increase/decrease prices to reflect the amount of utilisation of the network (the modified CRNP approach).

The paper goes on to add AEMC views about the imposts that the modified CRNP process might apply to TNSPs that do not use this and to highlight there is a deal of subjectivity inherent in the modified CRNP process. The AEMC then adds that having different approaches will increase the complexity of the inter-regional TUoS (IRTUoS) charging that is to be introduced.

The EMRF notes that increasing usage of assets that are under-utilised increases efficiency as does limiting increased demand on assets that are near capacity. In section 1.13, the EMRF observes that rewarding better end user behaviour now will lead to better utilisation of assets in the future. This philosophy leads to the conclusion that modified CRNP (despite the difficulties in its implementation) has the focus of providing rewards to encourage better utilisation of existing assets and avoiding future need for investment.

Regarding the AEMC observation that a change to modified CRNP might make the IRTUoS calculations more complex, the EMRF notes that the IRTUoS is intended to be a refinement with a minor impact on the costs of regional network charges. It would be bizarre if a minor issue was the used as the reason for avoiding what will deliver an overall improved pricing methodology. The AEMC argument implies that the "tail should wag the dog" rather than the other way around.

2.8 Excess demand charges

TransGrid prices its locational TUoS in relation to the highest demand incurred in any one month. Non-locational TUoS and common services are charged against actual energy or against the contract demand. If an end user exceeds the contract demand, it is charged a premium for breaching the agreed contract demand.

This raises the question as to why there is a premium. The EMRF considers that if the exceeding of the contract demand occurs and there is no harm why does there have to be a penalty, let alone a premium. The EMRF recognises that the contract demand needs to reflect the typical use the end user makes of the service, but queries what value is added by imposing a premium.

The contract demand is an amount that is agreed between the end user and TransGrid and therefore can be set to be typical of historic usage potentially moderated by known changes in usage. This recovers the reasonable costs the user imposes on the network but if it breaches the contract demand and the reasons are acceptable and TransGrid incurs no additional cost, there is no need for the imposition of an excess demand charge. If the demand increases consistently, then the contract demand would be increased as a matter of course by agreement between the end user and TransGrid.

The EMRF considers that there is no need for excess demand charges but there does need to be a mechanism whereby increases (and decreases) in contract demands can be agreed to reflect typical usage of the network.

2.9 AEMO approach to setting locational TUoS

The EMRF notes that AEMO has suggested that a user's demand be set as a fixed historical value and that this provides certainty as to what locational TUoS charges will be for the future. EMRF affiliate MEU has responded to the AEMO proposal rejecting this approach as it exposes consumers to unnecessarily high charges that they might not otherwise be liable for as a result of their operations.

The basis for the AEMO approach is not so much that it provides certainty for consumers but that it provides certainty of the AEMO income. This certainty is important for AEMO as it operates as a non-profit centre and is required to pay the providers of the network assets (particularly SP Ausnet and Murraylink) for use of their assets. If AEMO income is less than that which it has to pay out, it has to borrow funds to make payments. By fixing the charges on consumers, AEMO has less risk and a lower likelihood of not having sufficient funds for its commitments.

The AEMO condition for such "close balancing" of income and outgoings does not apply to TransGrid so there is no need to modify the approach to introduce the AEMO concept.

2.10 Side constraints and operating conditions

Side constraints are to limit price shocks to end users. Once established end users have little ability to react to locational price signals but actions of other users can lead to considerable change of flows and therefore to lead to quite significant price changes at specific locations. In particular, dispatch decisions of generators can lead to significant variances in flows in different parts of the networks. Such variance will vary with the time of day and the overall demand placed on the network. It is probable that dispatch decisions of generators will have a lesser impact on flows the closer the network is to operating at near the system peak demand.

TransGrid uses the computer software T-Price to generate its locational prices and assesses flows over every half hour for the year to generate its outcomes. As noted above, such an approach leads to an average outcome rather than reflect usage at peak utilisation of the network and therefore many of the flow calculations will reflect dispatch decisions when the network is under utilised and system demands are low. This is likely to result in considerable variation in flows compared to flows when the system is near peak demand and most generators are operating.

For example, at times of low demand in NSW, the coal fired generators in the north are likely to be providing most of the output and therefore flows are likely to be in a southerly direction[22] for all of the region. At times of high demand the flows will increase from the south by supplies from the hydro peaking generators in the Snowy and from Victoria.

Whilst flows from the north towards Sydney will see a moderate change as the system peak increases, flows to users south of Sydney will change from coming from the north to coming from the south, effectively a reversal of flows and evidencing considerable change. Thus, applying yearly average flows rather than flows at peak system demand times will result in only a moderate change for users north of Sydney, but there is a significant difference in flows between year long averages and peak system times for users in the south. This means that selecting average flows in preference to peak system demand flows means there is a considerable impact on consumers depending on where they are located caused by generator location and when they are dispatched.

The EMRF notes that there are intended to be side constraints on specific price movements yet EMRF members have noted that their charges have moved considerably more than the average price movement +/- 2% despite them not having much change in the demands. Further, the charts of the Albury price movements over time, provided in section 2.1 above, do not appear to be consistent with the application of the 2% side constraint requirement.

This raises the concern that perhaps the 2% side constraint meant to be applied is not being achieved.

[22] Moderated by inflows from Victorian coal fired generators

3. Responses to TransGrid questions

The EMRF provides the following responses to the specific questions raised in the Consultation Paper. The EMRF has endeavoured to keep its answers to the questions as concise as possible and refers to the commentary in the preceding sections to amplify its reasoning.

Chapter	#	TransGrid question	MEU response
2	1	**Do you agree with the transmission pricing objectives outlined in this section? Are there any other objectives for transmission that we have not identified?**	The EMRF has distilled all of the observations into four principles. These are detailed in section 2.2 (points 1, 2, 3, and 4) and outline a common theme of the principles presented by TransGrid in the three reviews noted. The EMRF considers that its four principles should be the basis for developing prices.
	2	**Which pricing principles or approaches do you consider should guide the future development of transmission pricing arrangements in the NEM?**	See response to Q1. As the EMRF points out in section 2.2, it is demand that drives the size of the network and to recover the costs using pricing that does not relate to the driver that results in the size of each element of the network assets is likely to result in inefficient pricing. TransGrid approach to recovering general and common services is not equitable and this point is made in section 2.3 and 1.10.
3	3	**Do you support the existing approach to setting transmission prices? If not, what other arrangements would you recommend that would better promote the National Electricity Objective?**	No. See comments in preceding sections
	4	**Do you support the limited flexibility**	The EMRF recognises that having rules that limit flexibility promotes

		currently provided to TransGrid in setting transmission prices? If not, what changes would you propose?	consistency of pricing approach across the NEM yet the flexibility that has been provided has resulted in a number of aspects where cost reflectivity has not resulted and there has been an inappropriate allocation of costs. There is no pressure on TransGrid to ensure there is cost reflectivity in its pricing such as would result if TransGrid was exposed to competition. Further, the revenue cap approach to revenue setting reduces any incentive on TransGrid to maximise cost reflectivity in its pricing. The EMRF does not consider that TNSPs should have greater flexibility in setting prices because there is no incentive on TNSPs to ensure prices are cost reflective The EMRF considers that the rules should require that TNSPs must provide the maximum reasonable level of cost reflective pricing and that the AER must develop a guideline that provides direction and instruction as to how this level of cost reflective pricing should be achieved.
	5	**Which aspects of the current transmission pricing arrangements, if any, should be amended to provide TransGrid with greater flexibility? If increased flexibility were provided, how should it be exercised to ensure that customers are treated equitably?**	See response to Q4 The EMRF has provided observations in the previous sections where it considers that TransGrid pricing needs to be modified
	6	**Are the existing arrangements that require TransGrid to submit a Pricing Methodology to the AER for approval**	No. See response to Q4

		appropriate? If not, what changes would you propose?	
	7	**Are the audit arrangements appropriate? If not, what changes would you propose?**	The audit approaches currently in place only address whether TransGrid has complied with its approved pricing methodology. The audit does not address whether the outcomes are appropriate nor do they assess whether the pricing methodology delivers the greatest extent of cost reflectivity in pricing practicable.
4	8	**Should the existing arrangements for determining locational based transmission use of system charges be amended and, if so, how?**	Yes. See comments in the preceding sections
	9	**Should TransGrid continue to apply the CRNP methodology or should it move to modified CRNP, or some other method?**	See comments in preceding sections
	10	**What operating conditions should be used for modelling purposes, and how should the pricing outcomes from these different conditions be taken into account in determining the applicable transmission prices?**	See comments in preceding sections, in particular sections 1.6 The EMRF considers that the costs of the network are driven by usage of the network at peak times, and those using the network at this time should contribute to the cost for providing the service based on usage at peak times.
	11	**Should TransGrid continue to recover network support costs on a locational basis by converting the cost to an equivalent asset value, or should these costs be treated as an operating cost and recovered through the common service charge?**	Network support is an alternative to providing assets and therefore its costs should be recovered from those which benefit from the alternative, just as for other assets. Whilst some TNSPs include network support as opex and include opex in common services, the EMRF considers that opex (along with network support) should be recovered as TUoS along with cost recovery of assets provided.

			This point is expanded on in section 1.9
	12	**Are TransGrid's existing pricing structures appropriate?**	No. See comments in previous sections, especially section 2.
	13	**What changes, if any, should be adopted in TransGrid's forthcoming Pricing Methodology proposal?**	See comments in previous sections
	14	**What changes, if any, should be made to the existing Rules to provide better pricing outcomes for customers?** **For example, should arrangements be put in place to allow customers greater certainty regarding the future path of transmission prices? Would such an arrangement be appropriate given the objectives of economic efficiency and equity?**	See response to Q4 The EMRF considers that the rules should provide high level principles and a requirement for guidelines to be developed to achieve the principles. Under a revenue cap approach, prices must vary to ensure that the allowed revenue is recovered. However a critical issue is that prices should not vary significantly relative to each other (see section 2.1 which shows that prices do not move in relation to others) and price movements should bear a relationship to the changes allowed in the revenue stream.
	15	**Should the current side constraint on locational TUOS prices be retained, or altered in some way, and if so, how?**	If prices are set cost reflectively and based on usage at peak times, it is probable that price movements year on year would not change significantly other than by changes in regional demand and allowed revenue changes. This should remove the need for any side constraints as they would retain a consistency relative to each other
	16	**What, if any, changes should be made to the existing prudent discount provisions in the Rules?**	The purpose of a prudent discount is to reflect that should a customer elect to cease to use the network, all other customers will suffer. A customer can elect to leave the network in a number of

			ways - bypass to another network (applies where the customer is located close to a boundary of the network), by reducing its demand (such as where its operating costs are too high and it ceases parts of its operation), by removing itself from the network (such as self generation[23]) or it ceases all activity. Under all of these scenarios there would be no reduction in the TNSP allowed revenue and the loss of revenue would have to be recovered by higher prices on the remaining customers[24]. Whilst the attention of the rules is devoted to the interests of the networks and the investments they make, there is no consideration as to the investments made by end users. In many cases they made their investments on the basis of certain network costs yet when these increase over time in excess of general inflation, they increase the potential for the end user to opt out of the network under any of the approaches Allowing a prudent discount to network charges provides some contribution from the customer rather than no contribution.
	17	**What additional information should TransGrid provide to improve the transparency of transmission prices and to better enable customers to respond to the pricing signals?**	The development of prices is not transparent at all. Even publishing the methodology does not make the process transparent as the mechanics of the price development are buried in the T-Price model which ties energy flows to asset values. No one assesses whether prices are truly cost reflective or whether the inputs used for modelling will result in cost reflectivity.

[23] The issue of self generation is an interesting issue for a prudent discount. If pricing is not cost reflective and overstates the costs an option is to self generate. In practical terms, this has two impacts - firstly it results in inefficient investment in the new generation assets causing the end user to incur unnecessary costs and reduces the contribution it made to the network revenue, increasing costs to all other consumers.

[24] Taken to the extreme, this premise results in the "death spiral" where more and more customers leave because costs are always increasing until no one remains connected.

			At the most basic level, as long as the prices in aggregate provide a revenue close to that allowed and the methodology process has been followed, the TNSP and the AER accepted the pricing outcomes. For a consumer to invest in assets, the decision is predicated on current pricing as future prices are unknown. The current provision of information is not sufficient.
	18	**What, if any, additional information should be provided to customers to demonstrate TransGrid's compliance with the approved Pricing Methodology?**	The EMRF considers that compliance with the approved pricing methodology is not the issue - it is whether the outcomes of the pricing methodology result in more cost reflective prices
	19	**In light of the information presented in this Consultation Paper, and your own commercial experience, how might the existing transmission pricing arrangements be improved? Please indicate whether you consider that the changes can be made within the framework provided by the existing Rules, or whether a Rule change would be required.**	See comments in preceding sections
5	**20**	**Do you support TransGrid's suggested approach and milestones for developing its forthcoming pricing methodology? If not, what changes would you suggest?**	The TransGrid proposed approach is better than what has been done before. The real test will be whether better outcomes eventuate.

Major Energy Users Inc.