Australian Energy Markets Commission

National Electricity Rule Amendment

Distribution Network Pricing Arrangements

[Reference No: ERC0161]

MEU member issues with network pricing

Submission
by

Major Energy Users Inc

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The views expressed in this document do not necessarily reflect the views of the Consumer Advocacy Panel or the Australian Energy Market Commission. The content and conclusions reached in this submission are entirely the work of the MEU and its consultant.

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The purpose of this document

Over the years, members of the Major Energy Users Inc (MEU) have seen their network prices fluctuate widely, despite the regulators (now the AER but previously the ACCC and state based regulators) advising that prices should increase in accordance with a formula - typically the CPI –X.. Most noticeably, this phenomenon of pricing not following the regulatory trends in overall revenue was observed in NSW where distribution prices for some MEU members increased in 2009/10 by an amount well in excess of 50% despite the AER determining that prices would increase within a range of some 8-16% depending on the network provider.

The MEU notes that the Standing Committee on Energy and Resources (SCER) has determined that a rule change is necessary to ensure that distribution network pricing needs to more closely reflect the inherent costs involved. The MEU welcomes this initiative.

Because the network costs for MEU members are a significant element of their input costs, they have had considerable direct experience with network service providers and their pricing; in particular members have why prices had risen above the changes implied by the regulatory decisions. The MEU provides the results of this experience with a view to highlighting issues that the AEMC should take cognizance of in developing the rule changes for distribution pricing.

This document summarizes the issues and experiences of MEU members as a result of networks applying their own unique approaches to network pricing.

1. About Network Pricing from a consumer view

Network service providers (NSPs) have a revenue trend provision determined as part of the regulatory reset process. From this, NSPs develop a suite of prices that are set annually and reviewed by the AER to assess whether the pricing methodology used is consistent with the pricing methodology approved by the AER at revenue reset.

Under a *revenue price cap arrangement* (which applies to all electricity transmission regulation and some electricity distribution regulation), the revenue in total must not exceed the annual revenue allowed in the regulatory determination. The amount of revenue allowed the NSP does not vary with the volume of energy transported.

Errors in network pricing which under- or over-recover the allowed revenue caps are rectified in the following year. However, this annual adjustment does not mean that the prices set by the NSPs are cost reflective and the actual prices may impose lesser or greater costs than are appropriate for the service provided.

Under a price cap arrangement (which currently applies to most electricity distribution networks and all gas transportation networks), errors in network pricing are allowed to go unchallenged other than to establish ex ante whether the pricing complies with the Rules; there is no review as to whether the actual prices are matched to the allowed revenue. The revenue a price-capped NSP receives is intended to vary with the amount of energy transported, so although the regulatory determination sets a revenue stream, the actual revenue stream will vary from that set by the regulator reflecting variances between forecast and actual usage.

Price-capped NSPs have the flexibility to adjust individual prices each year providing the annual growth of a "basket of tariffs" matches the annual growth in revenue allowed in the regulatory determination. Although there may be some side constraints to changes of individual tariff classes, price capped NSPs have a high degree of flexibility in the structure of the tariffs, even to the extent of introducing new tariffs at will and making others obsolete. This means that in addition to the NSP receiving a higher (or lower) revenue stream from the growth in volume of energy transported, the NSP can also receive a greater (or, most unlikely, a lesser) revenue than would be expected from the change in volume of energy transported[1].

What is also frequently seen, is that prices set annually change at different rates to the approved revenue trend. Consumers expect, and therefore plan for, the

[1] That this occurs has been observed by the regulator where price-capped NSPs have experienced lower than forecast volumes yet still achieved higher than forecast revenues because of the structure of the tariffs and the balance between consumption on different tariffs and tariff elements.

network prices they use to change by something close to the rate of revenue change set by the regulator.

Having significant differences between what the regulator forecasts is acceptable for movements in revenue and the change in actual tariffs set to achieve this revenue creates a great concern amongst consumers that the approaches to network pricing do not reflect the underlying value of the monopoly service provided.

1.1 The Network Pricing Rules

Under the transmission electricity rules the structure of the tariffs is set and using this structure provide tariffs that are reflective of the costs. In contrast, under the distribution electricity rules (and gas rules), networks are expected to provide pricing structures that reflect the costs for the services provided. As a minimum, average prices for a tariff class are to be developed so that they do not exceed stand alone costs for delivery of the service and are not less than the avoided cost for service delivery. This provides a very wide scope of possible pricing outcomes. In developing the prices, distribution NSPs "must take into account" the long run marginal cost of the service amongst a number of other factors. This effectively means that there is no strong requirement to ensure that prices are cost reflective.

Electricity distribution and gas NSPs have considerable flexibility in structuring their prices. In contrast, electricity transmission NSPs, the rules set the basis for pricing: prices must comprise entry and exit charges, common service charge, locational transmission use of system (TUoS) charge and non-locational TUoS (sometimes referred to as a general charge). Entry and exit charges are to be a fixed time based amounts, locational TUoS must be set on a demand basis (ie MW) and non-locational TUoS and common services are to be recovered on a "postage stamp" basis. However, transmission NSPs still can affect their pricing by setting the period over which demand is to be measured and by recovering postage stamped elements using either consumption (MWh) or demand (MW) of each customer connected.

Each NSP is required to prepare as part of their regulatory reset, a pricing methodology and this has to be approved by the AER. Once approved, as long as the NSP follows the approved methodology, there is no regulatory verification as to whether the prices that result meet any criteria for cost reflectivity. The most likely test for any cost reflectivity would be where a consumer identifies that the network price exceeds the stand alone cost and proposes a bypass of the network.

1.2 What are the drivers of prices?

There have been many reviews on how electricity network pricing should be developed, and it is recognised that there is no perfect solution to how pricing should be structured, or how to transition to such structures.

However, more recent work highlights that cost reflective pricing is essential if efficient demand side responsiveness is to be implemented. As 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. A recent Grattan report "Shock to the system - Dealing with falling electricity demand"[2] stresses this same point (page 14):

> "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."

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 operating at the peak demand of the network or the relevant region in the network (such as a transmission connection point). As demand is accepted as the driver of new investment therefore, in the past, demand was also the driver of that 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.

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 a daily charge), recovery using demand or recovery on a consumption basis, or some mix of these.

Acceptance of the basic concept (that demand is the driver of both new investment and was the driver for historic investment) has greater credibility on a theoretical basis as this provides recognition of what was provided in the past and why, as well as what needs to 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.

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

There are some fixed costs in providing the network service (eg overheads, network operation, etc) and these are referred to as common services in the electricity rules[3]. Cost reflective recovery of these is probably best achieved by allocation as a fixed charge, although volume and demand have also been used.

Pragmatically, meters used by the majority of users (mostly residential and small business) are not currently capable of measuring demand or usage over a short period. It is for this reason that, historically, volume has been the primary basis for charging for energy networks. Larger users of energy do have meters measuring demand and prices for large users are demand based although many networks still use a mix of demand and volume to recover costs even for large users.

Historic pragmatism has led to most prices being based on consumption, but even with only accumulation meters provided, some networks have sought to apply the concept of demand being the driver of costs by implementing increasing block tariffs as consumption increases.

1.3 The importance of cost reflectivity

The AEMC has provided SCER with a report on demand side participation (DSP), with the intention of increasing the amount of DSP in the market. DSP is seen as a tool to improve the capacity factor[4] of networks (to make them more efficient) because currently the market trend is towards higher peak demands for shorter periods, resulting in declining network capacity factors.

At the most fundamental level, unless network pricing is cost reflective then any DSP will be less efficient - if network pricing is lower than cost reflective, then efficient DSP will be seen as non commercial and if network pricing is higher than cost reflective, then inefficient DSP is encouraged.

If network pricing is structured to under-recover from one class of consumer, then inefficient DSP is incentivised for the customer class that is being overcharged, and efficient DSP prevented from the consumer class that is under-charged. The obvious example of where cost reflective pricing is not applied is where refrigerative air conditioning is used but charged for on a consumption (MWh) basis[5].

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[3] It is interesting to note that some NSPs also include maintenance of the network as a common service rather than as a locational cost. MEU members allocate their maintenance costs on a facility basis and not as a firm's "common service" cost.

[4] Capacity factor is the ratio between the average demand on a network and the peak demand experienced. Increasing the capacity factor results in better network utilisation and therefore implies less need for network augmentation.

[5] There are many reports that have identified this issue as a cause for some consumers being cross subsidised by other consumers

The AEMC has identified that network prices should be cost reflective in its Issues Paper on its review of distribution pricing arrangements.

1.4 An approach to cost reflective pricing

The arguments for ensuring better cost reflectivity are mainly qualitative and reflect the need to ensure equity and that network investment and DSP are both prudent and efficient as possible. As DSP has been determined as being an integral part of the changes proposed by the AEMC in its Power of Choice report, and the AER is likely to be responsible for developing guidelines for implementation of DSP, then a clearer definition as what is meant by the term "cost reflective" is required.

The "how to make prices more cost reflective" is more challenging than the identification of the need to do so. One approach to commence the process for addressing this might be for the AER to look at the issue following the approach used for its Better Regulation program, with networks, consumers and AER discussing issues in joint forums. This would require the networks to identify how they develop their prices now and why they implement changes. This approach would be an outcome if the AEMC sets principles for generating prices rather than being prescriptive as it was for the transmission pricing rules.

The AEMC proposes that using the long rum marginal cost (LRMC) for the network assets used to provide the service would assist in the achievement of cost reflectivity for pricing. The MEU is not convinced that this is so.

LMRC is intended to assess the cost of providing an additional unit of service rather than reflect the cost of the assets actually used to provide the service. This means that LRMC will allocate higher charges for an additional unit of service where there is no spare capacity in the network and lower charges where there is excess spare capacity. In the Transmission rules, use of LRMC is akin to the modified "cost reflective network pricing" (CRNP) approach used to price locational TUoS yet the reasons for most TNSPs not using the modified CRNP approach is because of the relatively high degree of subjectivity the approach imposes, the increased complexity involved and the resulting loss of transparency.

The major issue with using an LMRC approach is the requirement to establish an objective and equitable basis to allocate the "sunk" costs of the network which sit outside the LRMC assessment. The approach used to recover sunk costs will have the greatest impact on the whether the pricing reflects the actual costs each end user causes the network as sunk costs reflect the majority of costs in the network.

The revenue rules provide a target allowed revenue for the network to recover - the pricing rules provide the basis on how this cost recovery is to be achieved so that each end user pays for the service on an equitable basis. With this in mind, the MEU considers that the approach actually used in developing transmission pricing (ie allocating costs based on replacement value of the assets used) will provide an outcome that is cost reflective but not introduce the complexity of using an LRMC approach.

1.5 TNSP pricing impact on DNSP pricing

TNSP pricing has a locational element to it, although the power of this locational signal is modest because less than 40% of the transmission charge reflects location of the exit point[6]. Further, whilst the locational signal reflects the peak demand a user imposes on the network, the balance of the transmission charge reduces the strength of the signal for users to reduce demand at peak times. In fact, the signals actually used, actively encourage the occasional use of high demand plant and do nothing to shift this high demand away from times of peak system demand. Despite these obvious drawbacks, transmission pricing provides better signals for DSP than does distribution pricing.

Even though the locational and demand signals from transmission pricing are weak, DNSPs appear to reduce these even further by their approach to aggregation of all transmission costs which are then "smeared" across the various elements of distribution pricing in a totally non-transparent manner. Even those large users, who are able to request "pass through" of transmission costs in a transparent manner, find that distribution prices still do not provide clarity as to how the distribution prices have been developed.

The MEU notes that the approach by the AEMC to distribution pricing must address the impact that transmission costs have on distribution pricing (especially for those elements where transmission costs are a large component of the distribution charges such as for end users of sub-transmission and zone substations) and how transmission costs are to shared in a cost reflective manner. Unless this issue is addressed, the principle of cost reflectivity in network pricing will be further reduced.

The MEU considers that TNSP pricing rules need to be changed at the same time as distribution pricing rules so there is consistency in the principles underpinning all network pricing. This will result in better outcomes for the distribution pricing approach currently being undertaken.

1.6 Pricing and over-investment/excess capacity

The pricing approach used by all NSPs is that the replacement value of the assets is used to allocate the costs of each service provided. Inherently this

[6] This is because pricing for entry/exit prices are fixed and other charges recover the lower of a cost based on demand and consumption

means that, where assets are oversized for the service they provide, those end users connected to this element will be paying for capacity that is not used. The allocation of the costs for this spare capacity needs to be addressed otherwise the prices that are generated will be distorted.

This raises the question as to whether all end users should contribute to spare capacity wherever it occurs or whether only those end users who connected to the assets with the spare capacity should pay for the spare capacity that is provided.

2. Some background on the issue of network pricing

It is widely recognized that the cost of providing network services is the single largest element of the total cost of electricity delivered to customer connections. The cost of networks as a proportion of the cost of delivered electricity reduces as the voltage supplied increases, with those users receiving power at very high voltages (such 132 kV) and directly connected to the transmission network pay less for network services as a proportion of their total energy bills than those receiving at the lowest voltage - typically the 240V supplies at which most residential premises are connected.

As noted above, the cost of networks is driven by the peak demand that is envisaged will occur in the near future - typically the expected peak demand in the next 3-5 years. Network owners build their networks to accommodate this expected peak demand.

A review of the pricing structures (tariffs) provided by the various networks shows that the pricing and pricing structures developed by each network tends to be unique to each even though the basic premise is that the tariffs set will recover the revenue allowed by the regulator.

As well as being used to increase revenues above that identified by the AER as appropriate, pricing also has the ability to reduce the ability of users to better address their usage of electricity (eg such as the ways identified in the AEMC Power of Choice report) and so act as a barrier to better utilization of the electricity supply chain. So pricing of network services is a critical element for ensuring that consumers do not pay more than is needed to provide the network service and to remove barriers to better network utilization.

Even the pricing rules provided for transmission have sufficient freedom that allows each network owner to tailor its own pricing approach to meet needs other than equity; the distribution pricing rules impose almost no constraint on what is to be achieved through pricing. In practice, the network focus on pricing under a revenue cap is a second order issue. Under price cap regulation, networks are incentivised to maximize revenue through pricing. In neither regulatory approach is the network incentivized to maximize consumer interests and equity.

Pricing is the main area where there is tension between different consumer classes, such as the differing interests of large users and those of small users with regard to the cost of delivered electricity. There is a second aspect of this tension - one that lies between those users which have a "peaky" load (where high demand occurs for a limited time during the year) and those users which have a "flat" load (where their demand is consistent over the year).

To address this tension, the MEU considers there is a need for a policy direction that all users should pay their share of the value of the networks which they use, regardless of the frequency of the maximum demand each user places on the network. At the same time, those users with their peak demands occurring at times when the networks are not heavily loaded should not be required to pay the same as those whose demand causes the network to be sized for the occasional periods of very high demand.

The MEU has undertaken some analysis of the movements over time of network pricing by various network owners. This analysis shows that there are some major differences between pricing approaches and their structures used by distribution networks and even between transmission networks despite the structures for transmission being mandated in the rules.

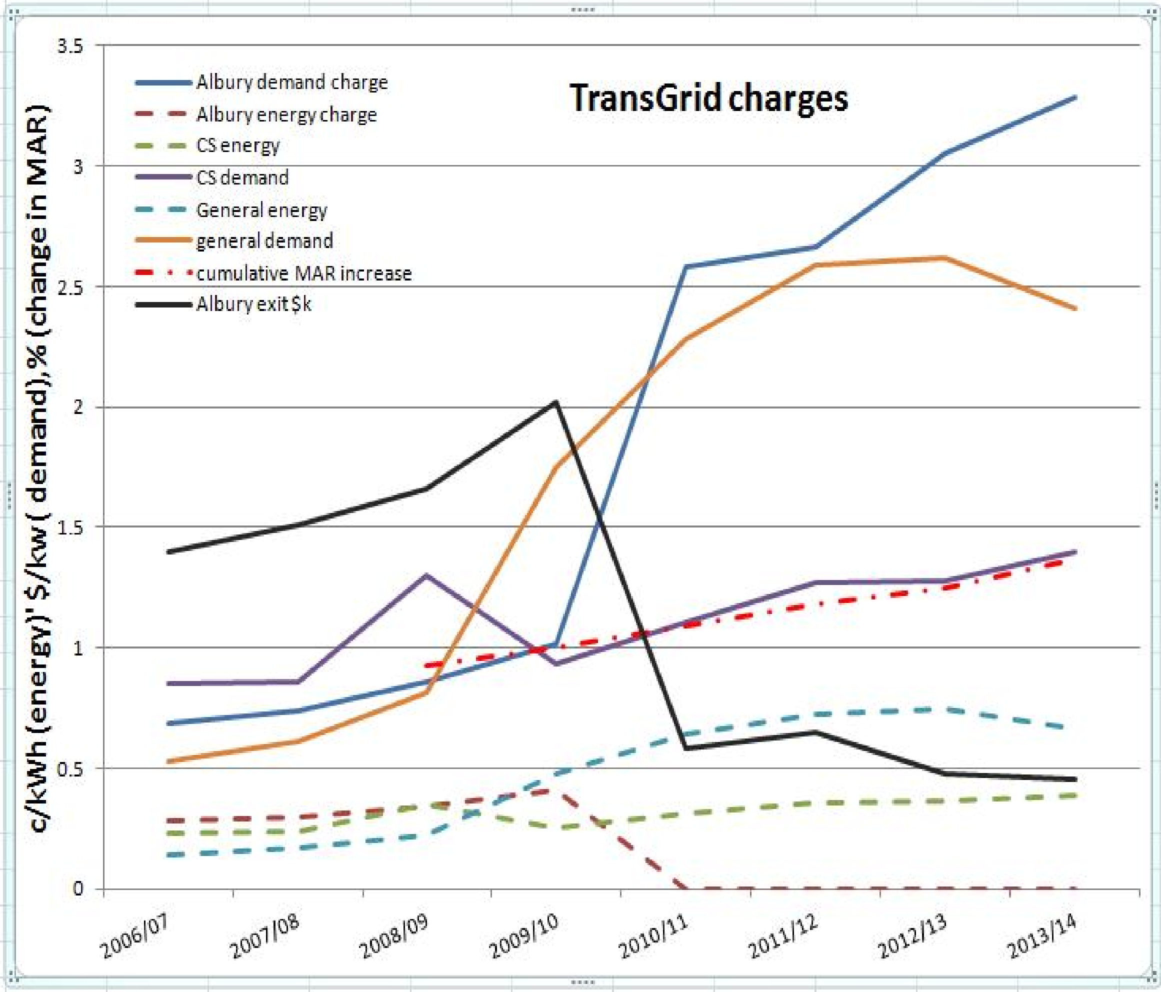
2.1 Transmission pricing observations and analysis

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

2.1.1 TransGrid pricing

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

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



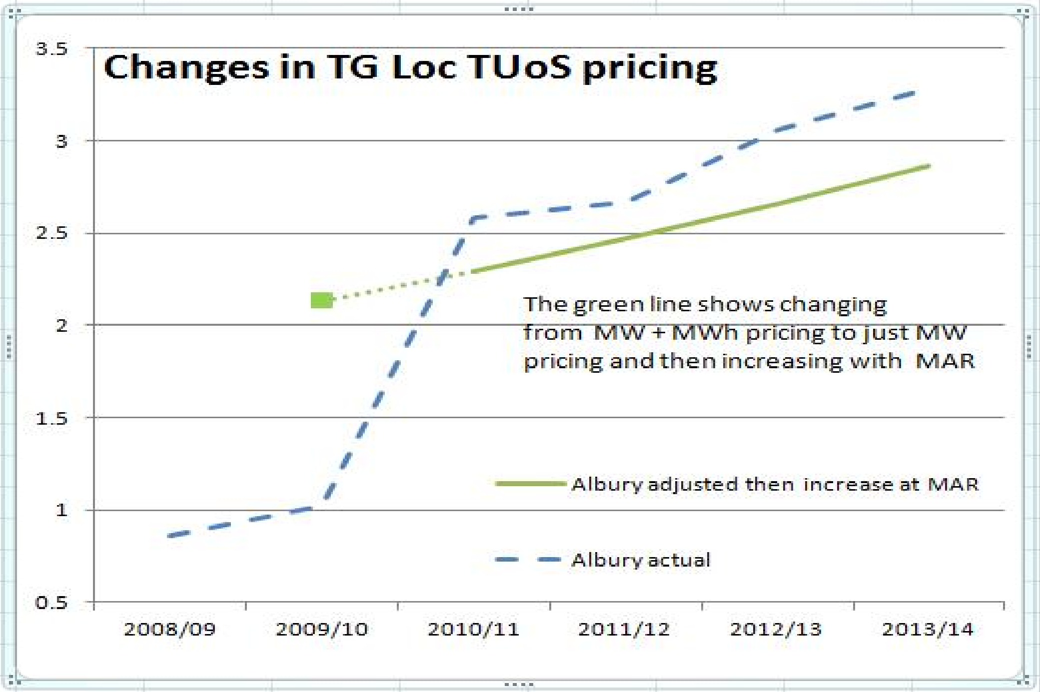
Source: TransGrid price lists

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

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

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

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



Source: TransGrid price lists, AER decisions, MEU calculations

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

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

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

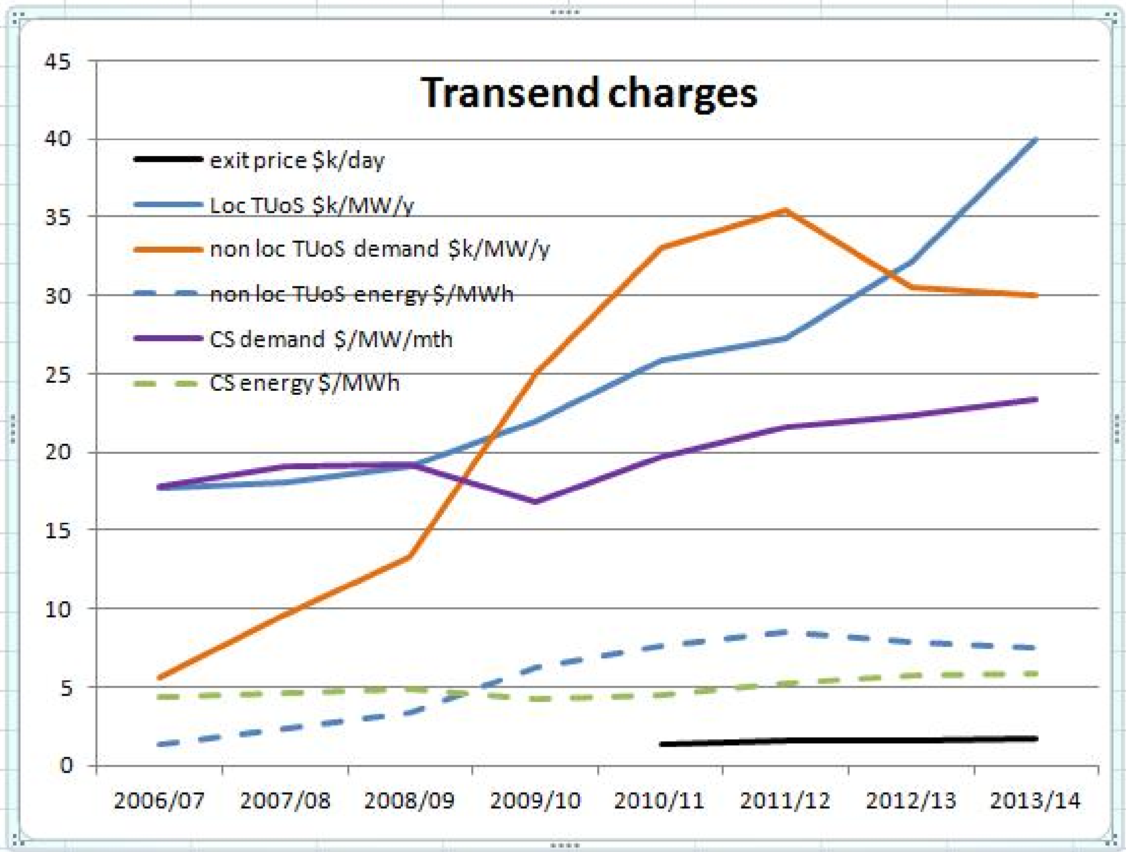
NSW. This means that those consumers in the south of the state pay for the Ausgrid and Directlink transmission - assets that they do not use.

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

2.1.2 Transend pricing

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

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



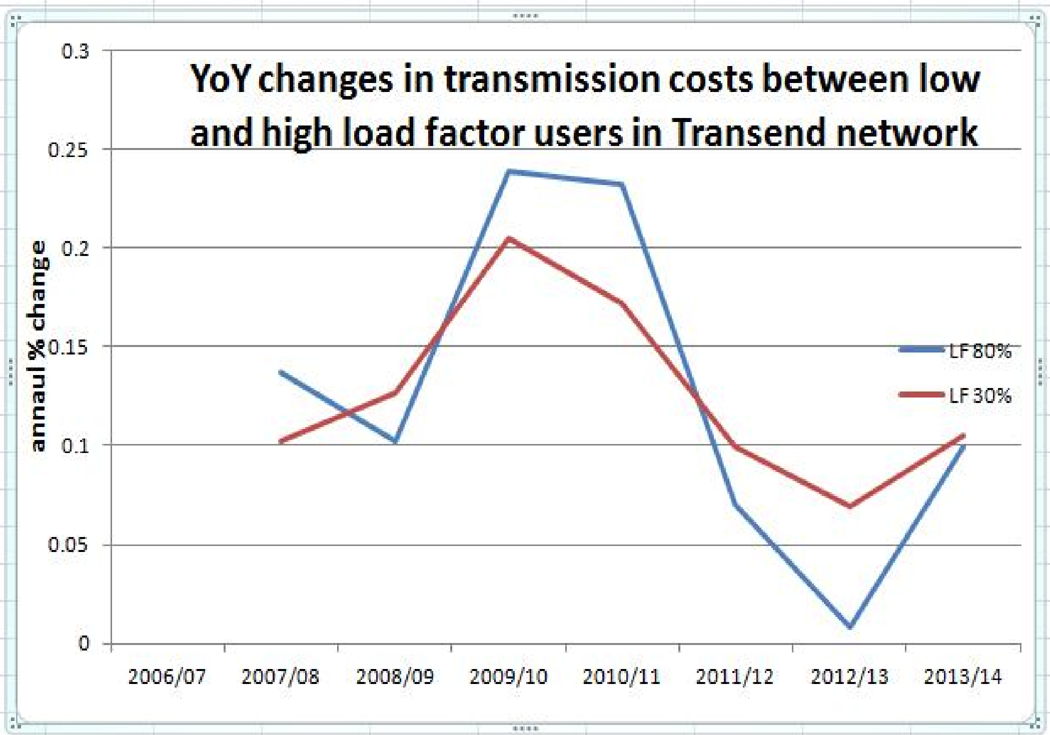
Source: Transend price lists

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

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

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

  This is shown in the following chart where the year on year changes in transmission costs for a high load factor user (80% load factor) transmission costs are compared with costs for a low load factor user (30% load factor)[7] despite both having the same demand.



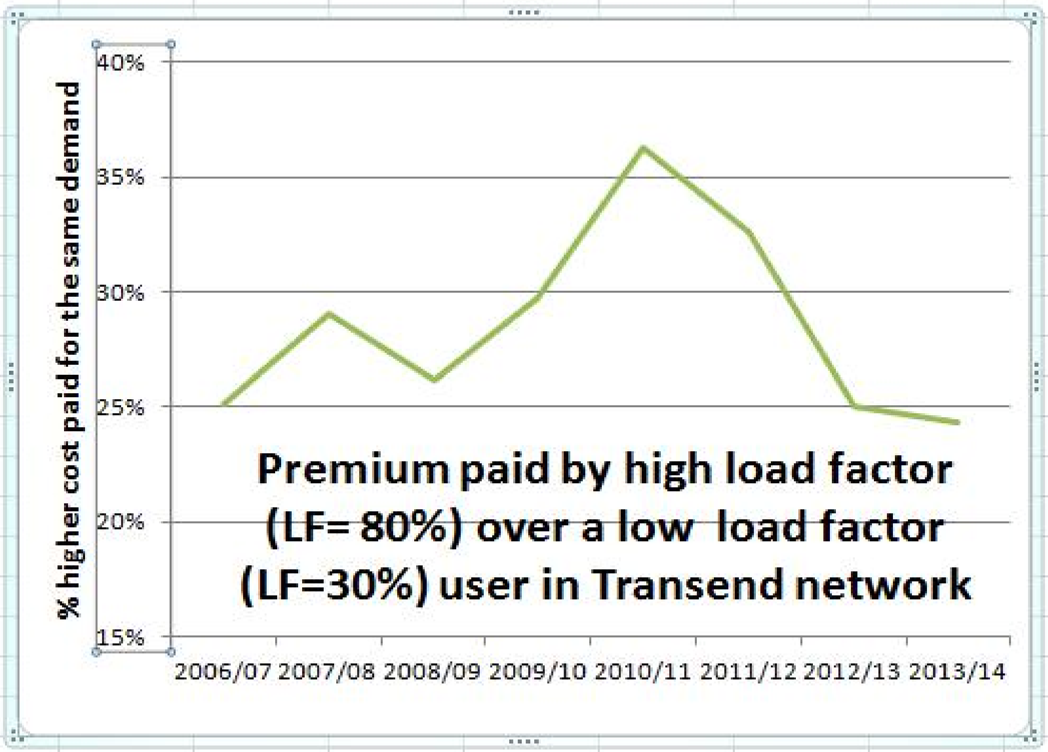
[7] The high load factor is typical of any one of the five largest users in Tasmania and the low load factor is the typical load factor on a state wide basis when the high load factor users are excluded.

Source: Transend price lists, MEU calculations

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

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

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



Source: Transend price lists, MEU calculations

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

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

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

2.1.3 Summary of transmission pricing observations

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

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

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

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

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

The review of the transmission tariffs highlights there is some variation between the networks in the approach they take to tariff development. Transmission prices, although more closely prescribed by the Rules, still exhibit significant differences, such as:

- AEMO assesses demand based on the 10 peak days in the year to set its prices whereas most TNSPs assess demand over an entire year
- Some TNSPs use cost reflective network pricing (CRNP) approaches and others use modified CRNP approaches to establish their prices.
- There are even differences between charging approaches where AEMO seeks to charge for its services based on historic usage applying well into the past, other TNSPs apply the highest demand incurred in the previous 12 months and TransGrid monthly charges are based on the highest demand incurred in the month.

The MEU considers that more care is needed to address the issue of improving cost reflectivity of transmission network pricing and the observations and comments resulting from direct interaction MEU members have had and reported to the MEU, will provide useful in the further investigations by the AEMC in relation to the rule change proposal.

2.2 Distribution pricing observations and analysis

In its Position Paper in March 2005 in relation to the Electricity Distribution Price Review 2006-10 (EPDR), the Essential Services Commission (ESC) observed that the five distribution businesses in Victoria had recovered more revenue than the ESC had expected, even after adjusting for the increased volume of electricity usage..

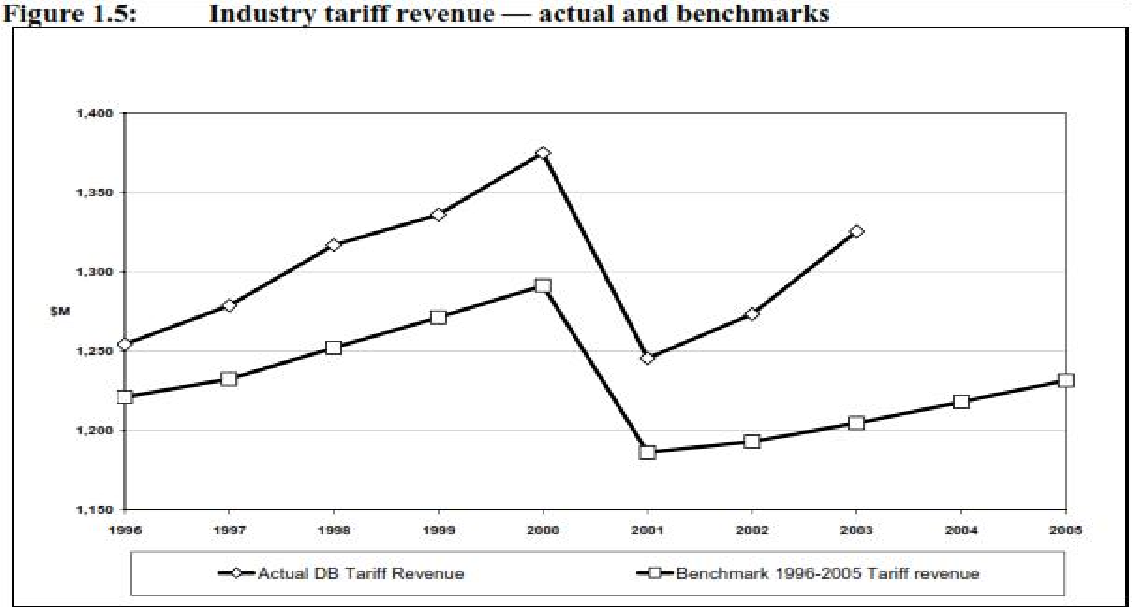
On page 11 of the Position Paper, the ESC noted:

> "*tariff revenue* for the 2001-03 period exceeded the benchmark level by 7.3 per cent, due to a combination of distributed energy being higher than forecast and the restructuring of tariffs in a manner that caused revenue to be higher than forecast for any given volume growth, for example, by increasing the variable component of charges by a greater amount than the fixed component. **The Commission's preliminary analysis suggests the latter had the more important effect;** (emphasis added)

The clear import of the ESC observation was that the five distribution networks had recovered more revenue that the ESC expected even after adjusting for the increases in demand.

The ESC provided the following chart showing that the excess in revenue recovery was significant, and showed a trend of the over-recovery increasing with time.

Figure 1.5: Industry tariff revenue — actual and benchmarks



Source: ESCV Position Paper for 2006/10 EDPR, March 2005

The ESC went on to state in its Position Paper (page 181):

> "As noted above, the Commission is not responsible for the individual tariffs and tariff structures that the distributors choose to introduce. The Commission sets an overarching price control that applies to the average price of a basket of tariffs and a set of side-constraints that attempt to place some economic discipline upon the distributors to develop tariffs that reflect the true cost of a customer's use of the network. Distributors are free to introduce, abolish or change the structure of their tariffs provided they comply with the overarching price control.
>
> However, as noted above, the Commission has concluded that there would be benefit in developing a structured framework and process for increasing the transparency of the distributors' tariffs and the basis for changes to their tariffs over time (see Section 11.1). Such transparency would include clear articulation of the cost allocation methodology used in developing individual tariffs."

Further, on page 175 of its Position Paper the ESC noted

> Despite the Commission's framework and approach and the focus that tariff strategies have had … the distributors' discussion on their tariffs for the 2006-10 regulatory period in their price-service proposals was limited largely to specific issues concerning the price controls, such as the future of the distribution re-balancing constraint. There was little discussion of how their

> proposals for removing or increasing the distribution re-balancing constraint for example, **linked to any overarching strategy of achieving more cost reflective tariffs or responding to customer demands** and which tariffs would be affected and by how much to achieve these objectives. (emphasis added)

The ESC then added (page 176)

> "In addition, some distributors have made marked changes in the component structure of their tariffs. For example, in their 2005 tariff proposals, Citipower and Powercor have removed the standing charge for their large, high voltage and subtransmission tariffs and reapportioned these charges across energy consumption components of these tariffs. Meyrick and Associates[8] (2005, p. 8) noted that:
>
>> *… the prices charged for the various output dimensions in Australia reflect historical precedent, distributor convenience and a range of cross subsidies that have proven hard to eliminate rather than cost reflectivity. The progression of prices towards cost reflectivity for each of the output dimensions is at best slow.*
>
> While some volatility in tariffs and tariff structure is likely given the operation of the price control mechanism, continual change in tariffs and tariff structure is likely to confuse and frustrate customers where the objectives and rationale underlying these changes is not clearly set out."

This articulation of the need to more closely control setting and movements of tariffs (prices) has never been implemented in any region, despite continuous commentary from consumers that the freedoms allowed distribution networks resulted in higher than expected revenues coupled with considerable and unnecessary volatility in prices and inequitable distribution of costs.

2.2.1 Tracking the changes

Whilst the MEU is aware of price changes that have occurred with specific MEU members and other consumers, issues of confidentiality prevent the use of such data. To overcome this constraint, the MEU uses notional consumer classes to identify the impacts of movements in tariffs over time.

The MEU analysis looked at the change in network costs over time for four classes of user:

- residential with 20 MWh pa consumption reflecting refrigerative airconditioning and other high energy use equipment

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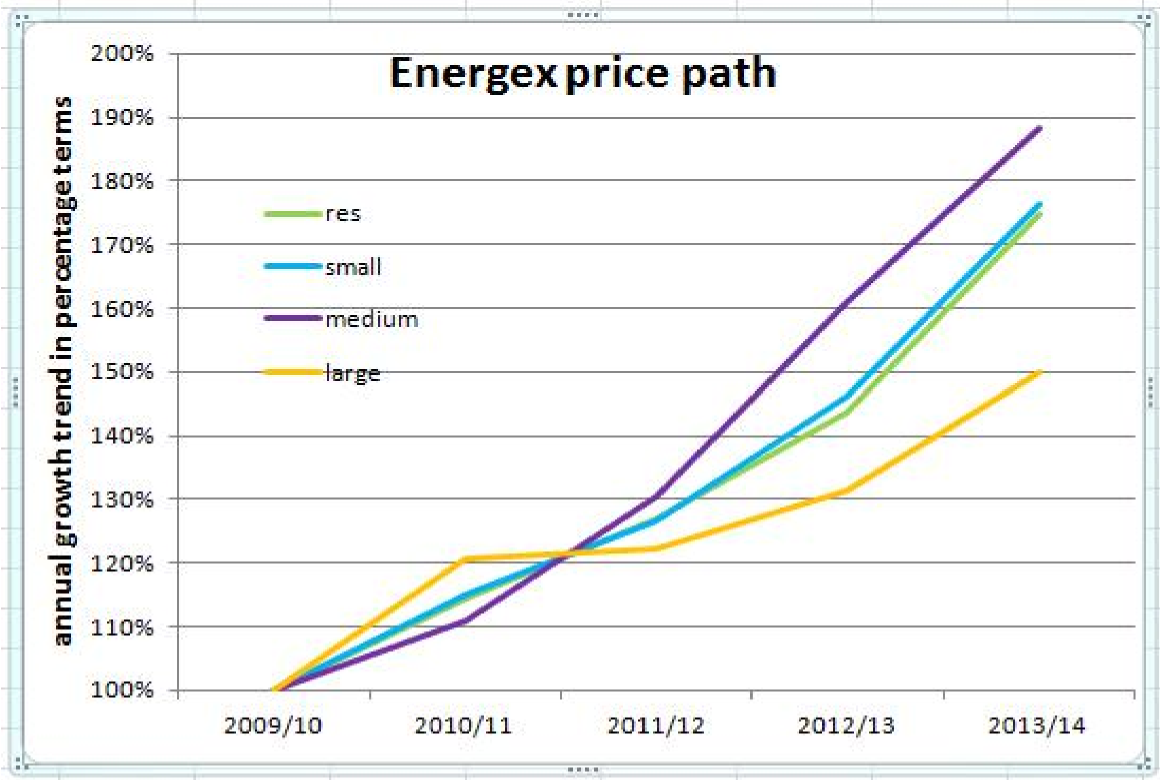
8 Meyrick and Associates 2005, *Review of Pacific Economics Group Report "TFP Research for Victoria's Power Distribution Industry: Report prepared for AGLE, CitiPower, Powercor, TXU Networks and United Energy* January.

- Small business (typically a shop with refrigeration) with 100 MWh pa consumption
- Medium sized business operating on a one or two shift basis on weekdays with 1000 MWh pa consumption and 500 kW peak demand
- Large business operating continuously with 70,000 MWh pa consumption and 10 MW demand

The MEU has analyzed the network price changes[9] for each class of user in four distribution networks - Energex in Queensland, Ausgrid in NSW, United Energy in Victoria and SA power Networks in SA.

2.2.2 Energex

The MEU has tracked the Energex network prices over the past five years[10]. The distribution costs for the four different load profiles were tracked and the following chart shows the costs each class of consumer would pay in each of the past five years.



Source: Energex tariff lists, MEU calculation

This shows that the there has been some variability between customer classes but inherent in the trends are some quite significant year on year changes. For

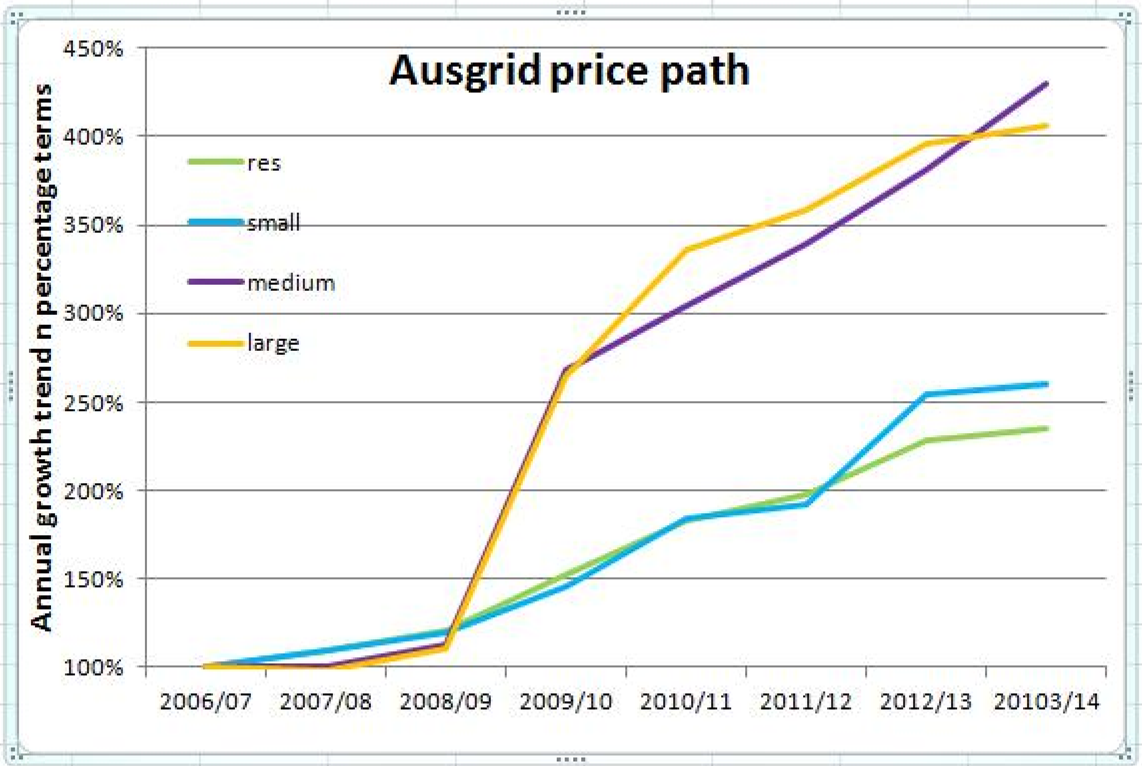
[9] It should also be noted that as retail prices were further constrained under retail price regulatory arrangements for small and residential users, the actual retail price changes may vary from the changes in the network tariffs.
[10] This was constrained by the non-availability of more historical data on the Energex website.

example, the costs for a medium business increased by over 23% for year 2012/13 compared to the previous year and in 2013/14, residential and small business saw over a 20% price hike.

This variability was not forecast in the AER decision on allowed revenue, where after a significant step increase for 2010/11, prices would increase by a little over 10% pa in nominal terms.

2.2.3 Ausgrid

The MEU has tracked the Ausgrid network prices over the past eight years. The distribution costs for the four different load profiles were tracked and the following chart shows the costs each consumer would pay in each of the past five years.



Source: Ausgrid tariff lists, MEU calculation

The massive increase in prices from 2008/09 to 2009/10 for large and medium businesses was reported by MEU members as was the rise again from 2009/10 t0 2010/11.

An explanation given by Ausgrid to MEU members for the large increase in medium and large user tariffs was a large price increase in TransGrid charges, and the analysis in section 2.1.1 does not support the assertion as rises in TransGrid prices between 2008/09 and 2009/10 were relatively modest[11]; the

[11] The spike in TransGrid prices seems to occur the following year

price changes by TransGrid do not explain the magnitude of the Ausgrid price increase seen just by medium/large users. In practice, any increase in TransGrid charges should have impacted residential and small users to a similar extent seen by other users.

The fact that, overall, Ausgrid prices for residential and small users show little change from the general trend seen in the three years prior to the large step increase in revenue Ausgrid was awarded by the AER and the Competition Tribunal in 2009 indicates a clear bias by Ausgrid in where revenue increases were to be levied. It would appear that a decision was made by Ausgrid that medium and large users would carry the bulk of the large increase in revenue awarded in 2009.

One explanation for this might be that there had been under-recovery in revenue by these sectors in previous years. To a large degree this argument is spurious as Ausgrid could have made some adjustments to these tariffs prior to the revenue adjustment in 2009, or even at the 2004 revenue decision, but did not see a reason for doing so. In fact, prices for residential and small business users merely reflect the trend in price changes over the previous 3 years.

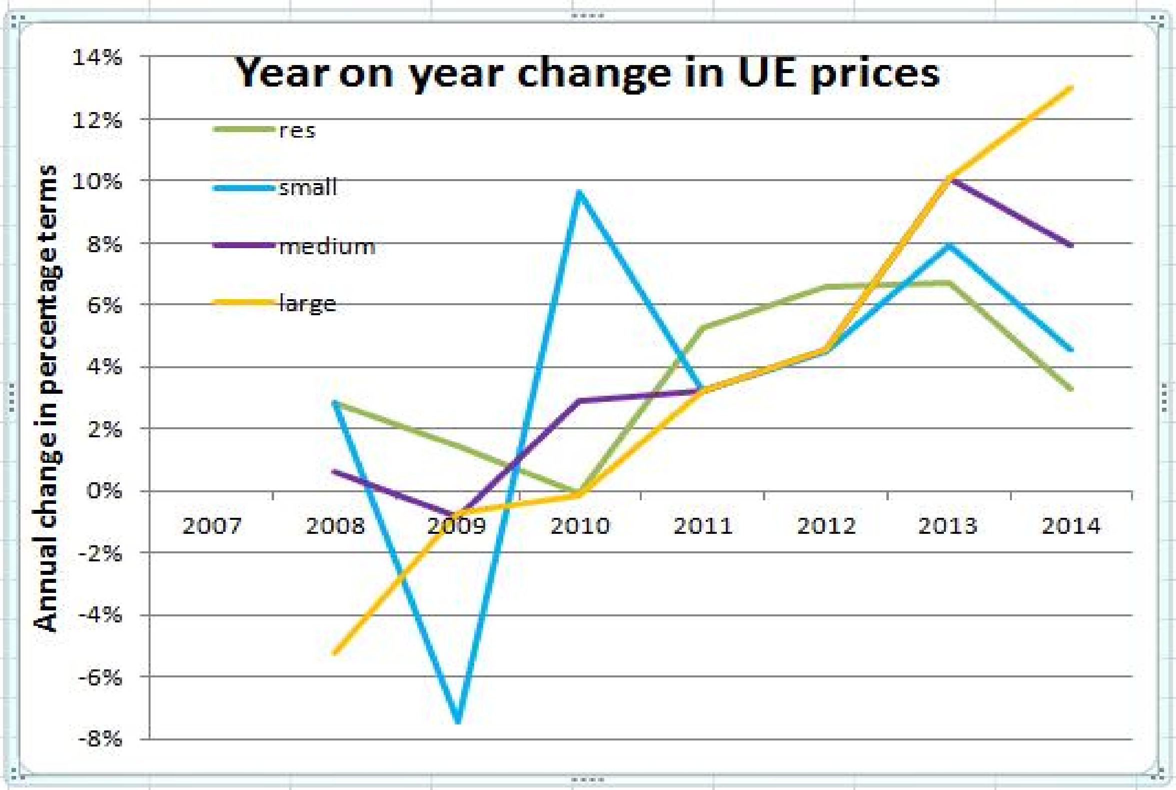
A major concern of medium and large consumers was the massive price hike about which they had no knowledge and therefore no ability to plan for the cost increases. The AER decision had indicated a step increase of some 15% would occur to the average tariff in 2009, yet an increase many times this actually occurred for the medium and large sector. That such an increase could occur demonstrates the clear ability a distribution network has to set prices to suit itself.

The fact that Ausgrid was able to so massively increase costs to larger electricity users yet allow residential and small business prices to remain at the same small annual price increase trend as previously applied **without formal explanation or independent verification** highlights consumer concerns that networks have little control placed on them as to how their revenue is to be recovered through pricing approaches.

2.2.4 United Energy

The MEU has tracked the United Energy network prices[12] over the past eight years. The distribution costs for the same four different load profiles were tracked and the following chart shows the year on year changes in costs each consumer would pay entering a new year above the previous year.

[12] This assessment of network tariffs excludes the impact of the mandated roll out of interval metering



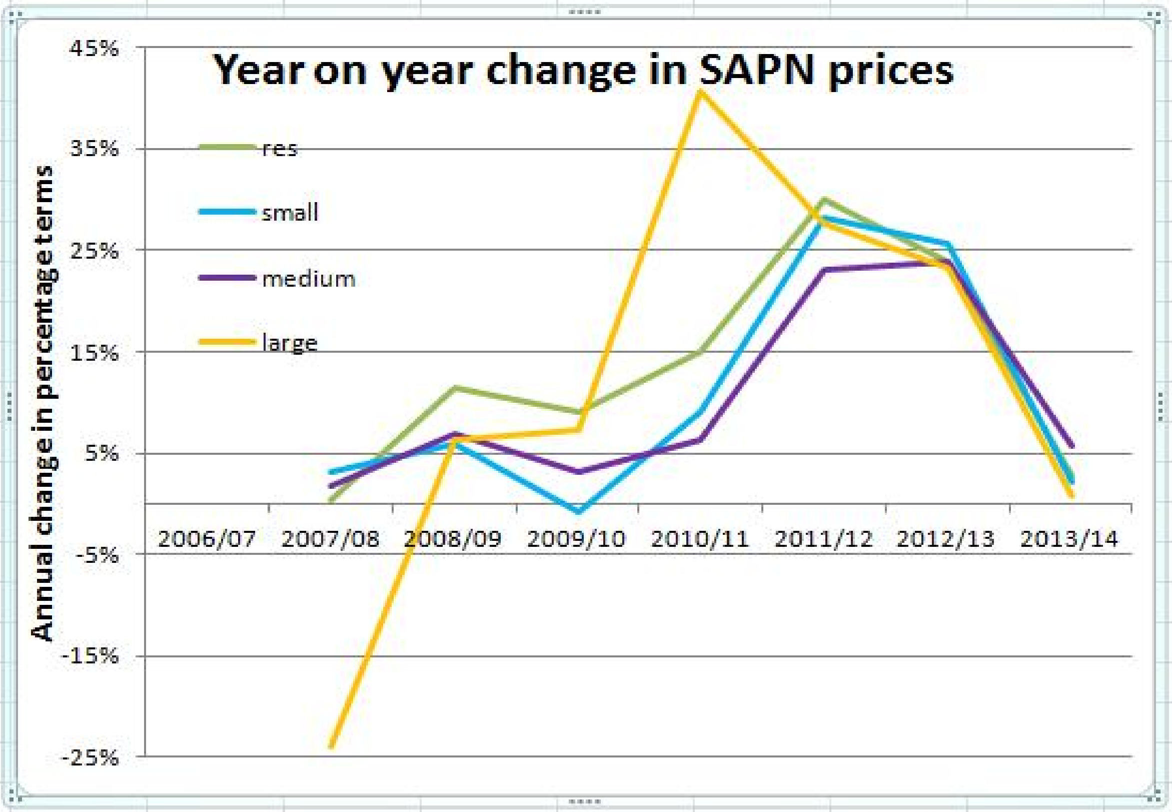
Source: UED tariff lists, MEU calculation

This shows that although there was been some variability between customer classes, there is a pattern where cost changes in some years reflect some consistency and which reflect the allowed changes in revenue. Despite this there are some massive swings as well.

For example, small business saw a large reduction in 2007/08 compared to the previous year, but only a year later saw an slightly lager step increase. Prices for 2014 see falls for three customer classes yet large business sees a 13% increase.

2.2.5 SA Power Networks (SAPN)

The MEU has tracked the SAPN network prices over the past eight years. The distribution costs for the same four different load profiles were tracked and the following chart shows the year on year changes in costs each consumer would pay entering a new year above the previous year.



Source: SAPN tariff lists, MEU calculation

This shows that although there was been some variability between customer classes, there is a pattern where cost changes in some years reflect some consistency between customer classes. Despite this there are some massive swings as well. For example, large business saw a large reduction in 2007/08 compared to the previous year, but two years later saw an even larger step increase.

The MEU is aware that some of the increases in tariffs resulted from the addition to network charges of the SA Government decision to include the solar feed-in tariff premium costs, and this resulted in the tariffs increasing at a rate greater than those implied by the AER determination and increased after the appeal to the ACT. However, it would be expected that the inclusion of these costs would have been equally reflected in the price movements for all classes of consumer.

2.2.6 Summary of distribution pricing observations

Whilst there is an expectation that there will be some year on year changes above and below the AER allowed X factors to accommodate changes in circumstance and exogenous impacts (such as government edicts) there is an expectation that the trends for changes in prices will be reasonably consistent between customer classes. This is not borne out in any of the pricing set by the four distribution networks. In fact, there is more than sufficient evidence to indicate that the networks do not attempt to deliver consistency in pricing over time, or to replicate the pricing trends based on the revenues allowed by the AER.

It might be asserted that the extent of the changes from trend reflects the changing mix of consumer classes. The MEU finds this difficult to accept as, whilst there might be some changes in mix, the changes year on year would be very modest and certainly not to the extent shown by the variations seen in the above examples.

As the commentary provided by the Victorian Essential Services Commission in its review of revenue allowances in 2005 seems to imply, this variability in prices does not support a view that prices are cost reflective, and that the issue of non-cost reflectivity of prices is one of long standing.

The MEU would go further. This variability in prices has demonstrated that networks regulated under a price cap approach have the ready ability to increase their revenues in excess of the allowances provided by the regulator, even after making adjustment for any variability between forecast consumption (on which the weighted average price cap basket of tariffs is predicated) and actual consumption. Price cap regulation and the freedom to set tariffs as desired, provides a strong incentive on networks to manipulate tariffs to increase revenue above that allowed[13].

In addition, there is an expectation that price trends for different customer classes would replicate the general trend for changes in the allowed revenue. This allows greater certainty in year on year changes for the costs of distribution; as a general observation, consumers would expect that prices would closely follow the AER assessed X factors allowed for each network.

The fact that there is considerable variability year on year of prices for different customer classes implies that the main aim of the distribution networks is not cost reflectivity (as the Rules state as being an aim for distribution pricing) but for other reasons more in the interests of the networks.

Another issue (also referred to in section 2.1.3 above) is how distribution networks incorporate the transmission charges into the distribution prices. The locational signals provided by transmission are lost in the translation as are the pricing signals to manage changes in demand.

This review of distribution tariffs highlights there is considerable variation between the networks in the approach they take to tariff development. Distribution tariff structures vary widely. For example:

[13] The MEU has seen examples where price capped networks (especially gas networks) achieve and even exceed the allowed revenue despite consumption being less than that forecast, supporting the view of price manipulation.

- There is considerable variation between regions as to what periods are peak, shoulder and off peak times, although peak and shoulder periods tend to be during the daylight times and early evening on week days.
- Despite the regional variation between peak/shoulder/off peak times, there is poor correlation between the networks determination of peak/shoulder/off peak with the actual variation of usage seen in the electricity market.
- The tariff structures vary considerably between regions:
    - Energex in Queensland has an access fee and a single consumption charge for all users with medium and large users also paying a demand charge.
    - Ausgrid in NSW has an access fee for all users, peak, shoulder and off peak consumption rates for smaller users and for larger users peak, shoulder and off peak consumption as well as demand charges
    - United Energy in Victoria has charges for summer peak, other peak times and off peak consumption. Small consumers pay an access fee but large users do not. Large users pay on a different basis with summer demand and other time demand as well as consumption rates for summer peak, other peak times and off peak usage.
    - SAPN in SA has an access fee and up to 4 blocks of consumption rates for smaller users, larger users have no access fee but up to 4 blocks of demand costs for with rates for consumption for peak and off peak usage

The MEU noted that in addition to the tariffs used for the analysis, each distribution network had many more tariffs with multiple tariffs being able to be applied to the same class of consumer, adding further to the confusion. This proliferation of tariffs does not necessarily lead to greater cost reflectivity, but an approach by consumers to seek the tariff which results in the lowest cost they are likely to incur.

The MEU considers that great care is needed to address the issue of pricing structures to achieve the aim of improving cost reflectivity of network pricing. The observations and comments resulting from direct interaction MEU members have had and reported to the MEU, will provide useful in the further investigations by the AEMC in relation to the rule change proposal.

3. Conclusions

This report, triggered by the first hand experiences of MEU members and other consumers, highlights that the aim stated in the electricity rules for cost reflectivity in pricing, is probably not being achieved under the current rules. This certainly means that to achieve the outcomes of the Power of Choice report a great deal of change is required. In particular, there needs to be direction as the how cost allocation is to be implemented and how tariff are to be structured so that cost reflectivity is engendered.

The AEMC has initiated a rule change process on the proposal by SCER for network costs to be more cost reflective as this is seen as an integral step to implement the outcomes of the Power of Choice report. The MEU supports this activity and sees this report as part of providing information on current network price setting outcomes.

3.1 Transmission pricing

The MEU analysis of the pricing of transmission services, shows that even with the degree of prescription provided in the rules for transmission pricing, price consistency is still not being achieved, implying that cost reflectivity is not the prime focus of the pricing methodologies being used. In particular the flexibility provided for transmission networks still results in a variety of approaches used by different networks which result in considerable diversity of outcomes.

Under the Chapter 6A rules, there is a degree of prescription provided that the transmission network service providers (TNSPs) must implement in order to develop their prices. The intent of this pricing approach is to ensure there are adequate price signals to engender appropriate demand side responses so that greater efficiency of transmission asset utilisation is achieved. Despite the effort put into transmission pricing to generate certain outcomes, the reallocation by distribution networks generally undoes what is provided by the transmission networks.

Each TNSP is required to provide a pricing methodology as part of the revenue reset process. This methodology has to be approved by the AER. Whilst the level of prescription for transmission pricing is greater than for distribution pricing, there still remains significant flexibility for each TNSP to implement its own approaches. The AER review of the outcomes of the methodology is limited and there are few principles that underpin the requirements of the rules. Even though there is a high level aspiration that prices will be cost reflective, cost reflectivity itself is not a principle that is expressly stated.

This means that the AER review of transmission pricing is quite limited. As a result there is significant variation between the methodologies of the different TNSPs. The fact there is such diversity of outcomes (both between TNSPs and even year on year price movements within a TNSP) indicates that the prescription included in Chapter 6A is not resulting in efficient transmission pricing. It would be more effective if the rules provided a set of principles and outcomes sought, rather than being prescriptive, allowing the AER to develop guidelines which are to achieve the targeted outcomes.

3.2 Distribution pricing

Distribution pricing rules have little prescription as to how pricing is to be implemented, allowing distribution networks considerable freedom to price anyway they wish. At most, distribution networks are required to ensure that the average price for the "basket of tariffs" they use for price movement control does not exceed the AER allowed movement in revenue (the X factor) with some tariffs set within a regulatory period not to change more that a side constraint set.

Price cap regulation is intended to provide an incentive on networks to increase the usage of the network and thereby increase its load factor; but in practice load factors have trended to lower levels rather than increase. In theory, price cap regulation could provide incentives for DSP but the pricing approaches used by NSPs tend to ensure that DSP does not occur.

In practice, the MEU have seen priced capped DNSPs use the flexibility allowed under the rules to set prices and price structures to meet the requirements of the rules yet still recover more than the revenue the regulator considers appropriate. The MEU has even seen instances where under price cap regulation demand and consumption has been less than forecast but even so the DNSP has recovered more than the expected revenue This shows that the ability to manipulate tariffs is a profitable aspect of DNSP activity under price cap regulation.

Revenue cap regulation is intended to ensure that the NSP recovers its allowed revenue, regardless as to whether the forecast of demand and consumption was accurate or not. Revenue caps reduce risk to NSPs but limit the ability to "game" the system. The MEU has noted that the outcome of revenue cap regulation imposes no incentive on the DNSP to ensure that its prices reflect costs. As a result, the pricing structures tend to become the most convenient for the NSP, with little regard as to what the intent of the pricing is to achieve, other than recovery of the allowed revenue.

3.3 Demand side participation (DSP)

MEU members have reported a number of DSP projects prevented because of pricing structures applied by both TNSPs and DNSPs[14]. In the case of DNSPs, there are three significant pricing approaches that militate against DSP:

[14] In addition, this same point is made in a report for Australian Pork Limited by Lim and Headberry "Technical, Economic and Financial Implications of Using Piggery Waste to Generate Electricity" available at http://citeseerx.ist.psu.edu/viewdoc/download?doi=10.1.1.117.4706&rep=rep1&type=pdf

- Peak demand is the key driver of augmentation, yet pricing generally recovers NSPs costs based on consumption. This means that projects which would reduce the occasional peak demand do not proceed because they are not commercial.

- End user demands are the basis for cost recovery regardless when the peak demand occurs. A user's peak demand sets the basis of charging regardless as to when the usage occurs - using power at peak system times incurs the same cost as using the power when there is spare capacity in the network. This means that projects for load shifting[15] do not occur.

- To achieve the benefit of DSP, usually a number of DSP projects operating concurrently are needed to deliver the sought after network benefit, yet each DSP project is assessed on an individual basis by the NSP. Usually the benefit of a DSP project assessed in isolation does not deliver the network benefit sought. As a result none of the DSP projects proceed - it is multiple DSP projects that provide the diversity of usage that delivers the network benefit rather than single unique projects.

3.4 What is needed?

The MEU considers that consistency of tariff development across the NEM is an outcome that should be sought, but what is just as important is that the prices that result must be such that encourages efficient demand side participation. What the MEU members see now is that many DSP projects have not proceeded at the transmission level mainly because of the pricing approaches used, despite the AER overview of pricing methodologies; DSP at the distribution level is virtually non-existent because of pricing structures.

In practice, the MEU does not consider that there needs to be a different set of pricing principles between transmission and distribution; removing the prescription in the transmission rules and imposing the same set of pricing principles on both transmission and distribution would allow consistency

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[15] There are many ways an end user can assist in reducing the need for network augmentation and increasing the load factor of a network. Load shifting is seen as benefiting the network yet when this occurs, the benefits to the end user are overlooked. For example, if an end user shifts its demand from a time of high peak demand on a day to a time of lower demand, there is no benefit provided from the network, because the end user is charged for its demand regardless of when it occurs. Under some DNSP tariffs, the end user might get a benefit if the load was shifted to an off peak time (but not all DNSPs offer this) but off peak periods during the working week are limited to after 10 PM or later through to 7 AM making access to off peak demand tariffs difficult to acquire.
In a similar vein, an end user transferring its peak usage to a time of the year when demand is low (as might be the case for a self generator scheduling its maintenance) there is no benefit provided as demand charging is based on the actual peak demand rather than when it occurs. Such a standby arrangement is very uncommon yet encourages load shifting.

between pricing for the two sectors; having different principles would result in different outcomes between the two sectors.

With prices being required to be and verified as cost reflective, there should not be the ability to manipulate tariffs and recover more than the revenue the regulator considers is appropriate. However, just stating that prices are to be cost reflective will not achieve cost reflectivity and the regulator needs to be provided with the power to ensure that actual prices provided are cost reflective. This would also prevent the over-recovery of more than the expected revenue should demand and consumption occur as forecast.

The rules need to expressly state principles for what the network pricing approach is to achieve with the AER being required to develop guidelines so that NSPs will develop a pricing approach that will be cost reflective. The AER should also be required to assess the pricing and pricing structures to verify that the methodology used actually delivers the desired outcomes.

There are four other issues that need to be addressed:

1. Rule changes are required to reduce the scope allowed NSPs to develop their own price structures. Included in this is a need to ensure that NSPs do not have the easy ability to "game" the tariffs.

2. Multiplicity of tariffs for the same customer class needs to be curtailed

3. Tariff structures should be standardised with the development of prices made transparent with the same allocation of costs incurred by all networks made to the different fixed and variable elements.

4. When tariffs are adjusted each year, the outcome for each consumer should be that the new tariffs generally follow the revenue trend that the regulator allows at the reset. Any tariff that has a different trend change should be identified and the reasons why explained and substantiated as appropriate. The MEU notes that the new rules require the development of pricing plans for distribution but the MEU considers that such pricing plans are insufficient to prevent each distribution network still implementing pricing that deliver the biases seen in the current pricing. Transmission network pricing, despite having to be developed under approved pricing methodologies still exhibit considerable unnecessary year on year variations and biases.

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

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

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[17].

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.

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

[17] 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’).

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"[18] 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.

[18] 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[19] 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 Victorian transmission charges. Users on the NSW side pay about twice

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

as much for their transmission system services as users on the Victorian side of the city pay.[20]

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[21] 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 recovers the monthly locational TUoS on the basis of the highest demand

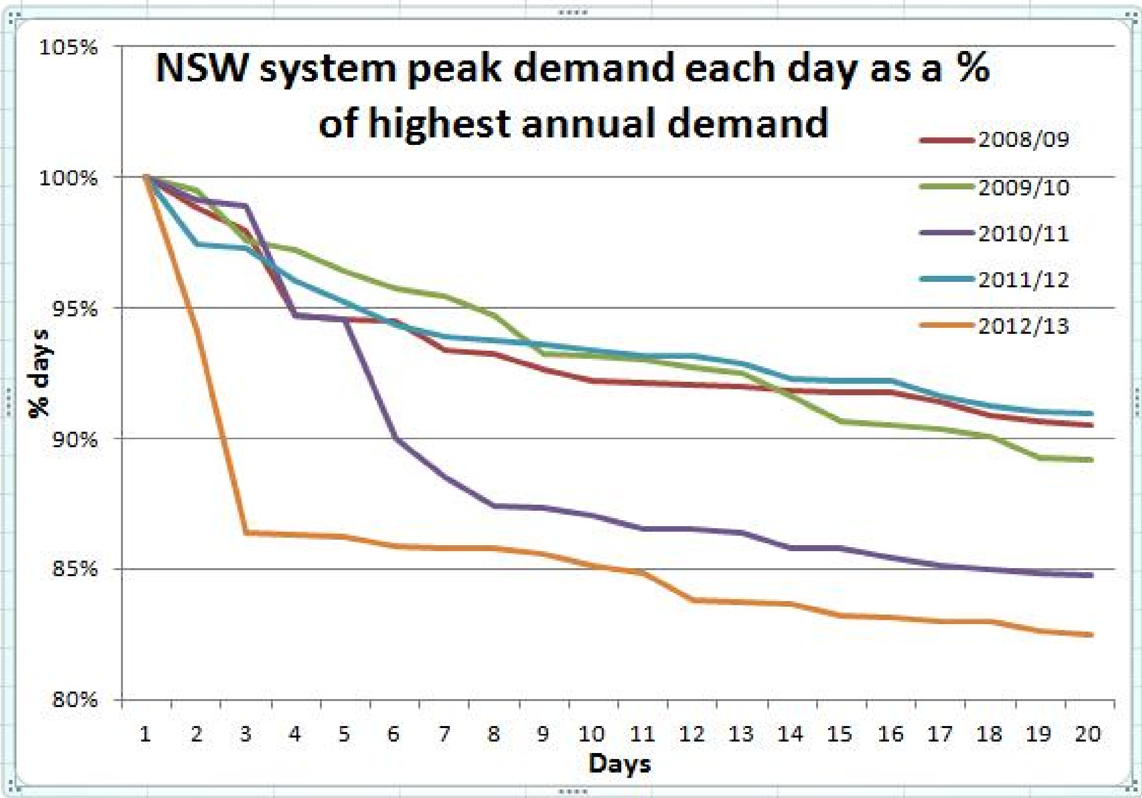
[20] Similar differentials can apply between adjacent distribution regions as well, highlighting the need to address the issue widely.

[21] 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.

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[22] 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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[22] 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[23].

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.

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[23] 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[24] 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[25], ElectraNet states:

> **"6.12 Standby service arrangements**

[24] 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.
[25] 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."

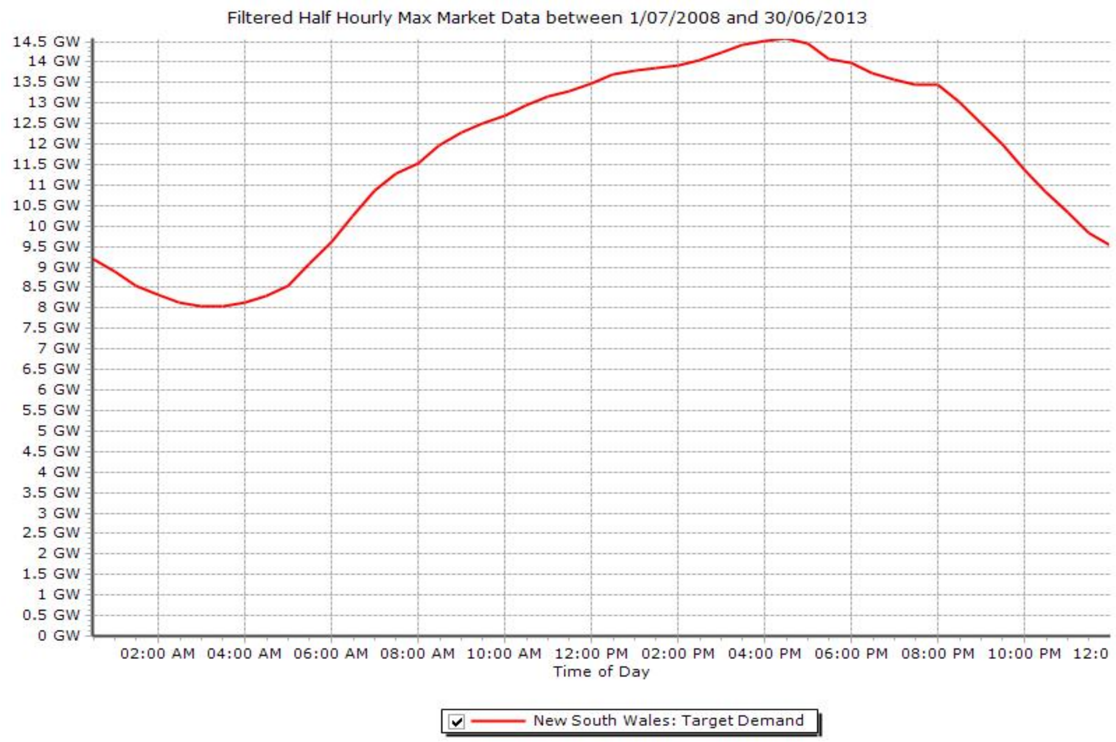
On this basis the EMRF supports the AEMO approach to pricing its network services and considers that charging for services should be made on the basis of usage only at peak usage times. This means that those causing the network to be sized to serve the peak demands would be exposed to the costs they 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.

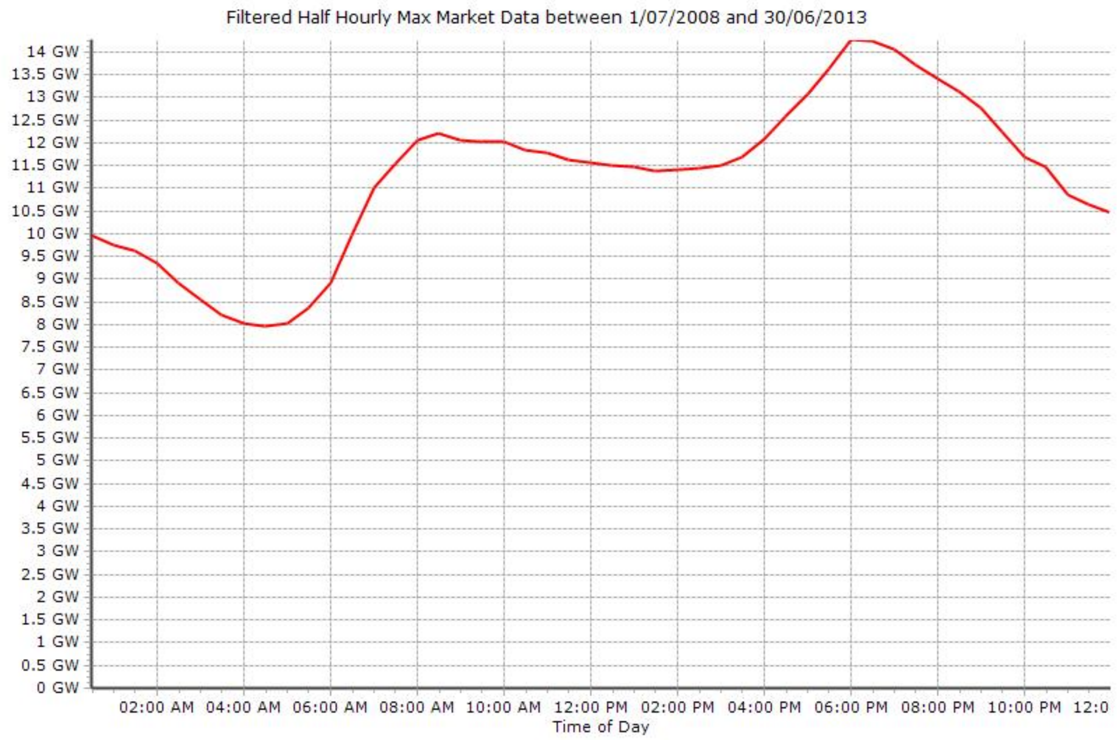
1.12 Time of use pricing

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.

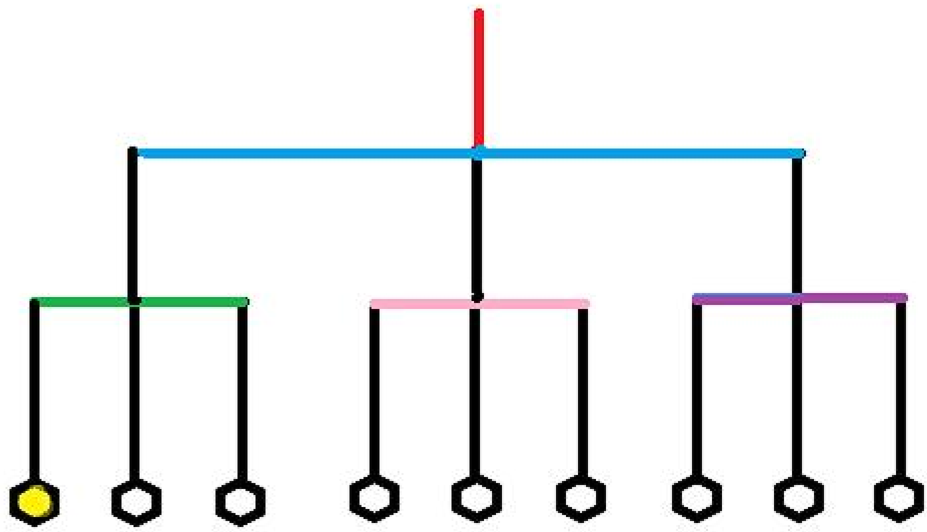
Charges calculated on usage during the times of the day of peak demand (rather than usage across the whole day) would provide a clear signal to end users to reduce their usage at times when the network is most likely to be heavily loaded.

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[26].

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.

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[26] 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[27]" 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[28] 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.

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[27] 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)

[28] 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.

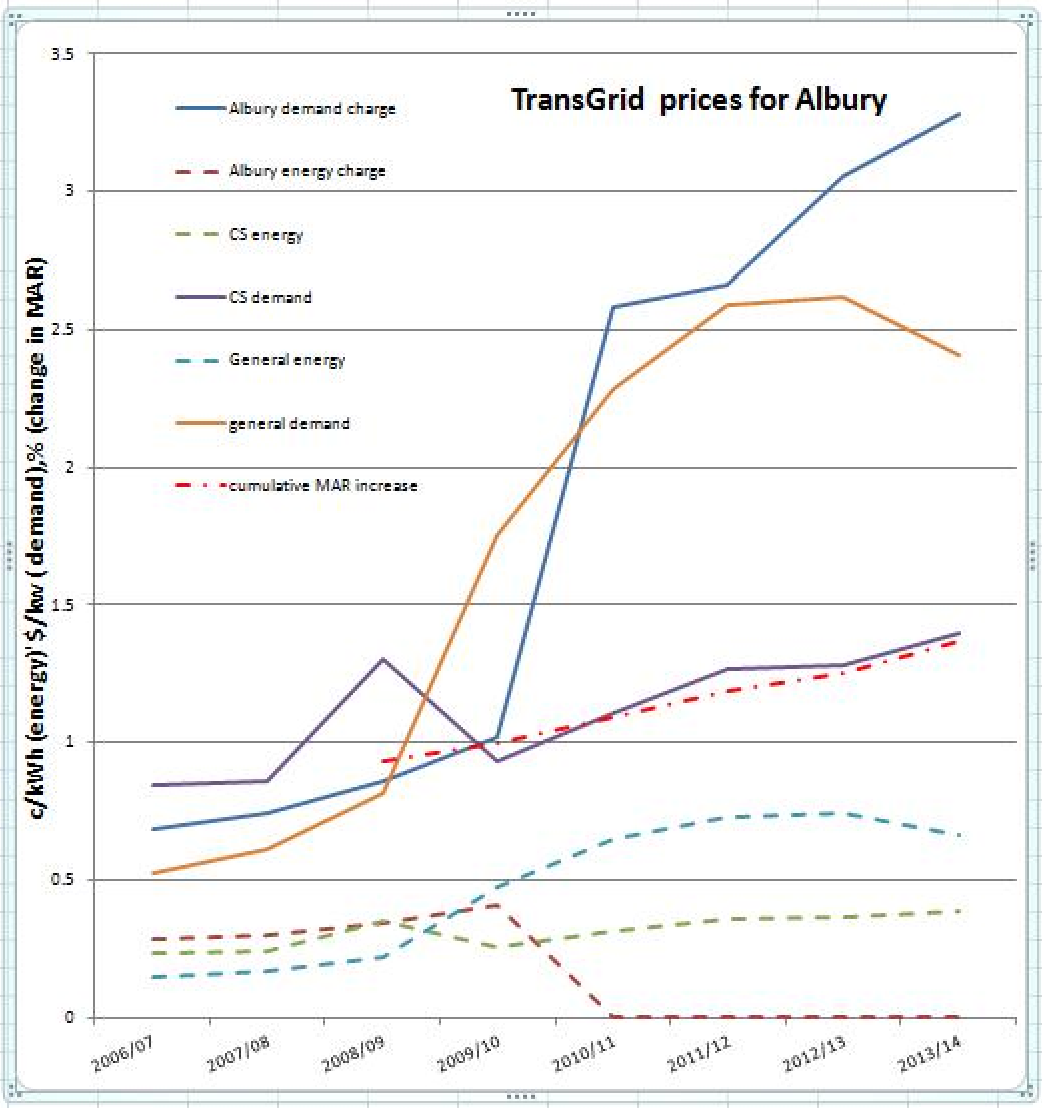
2.1 TransGrid's focus on cost reflective network pricing so far.

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

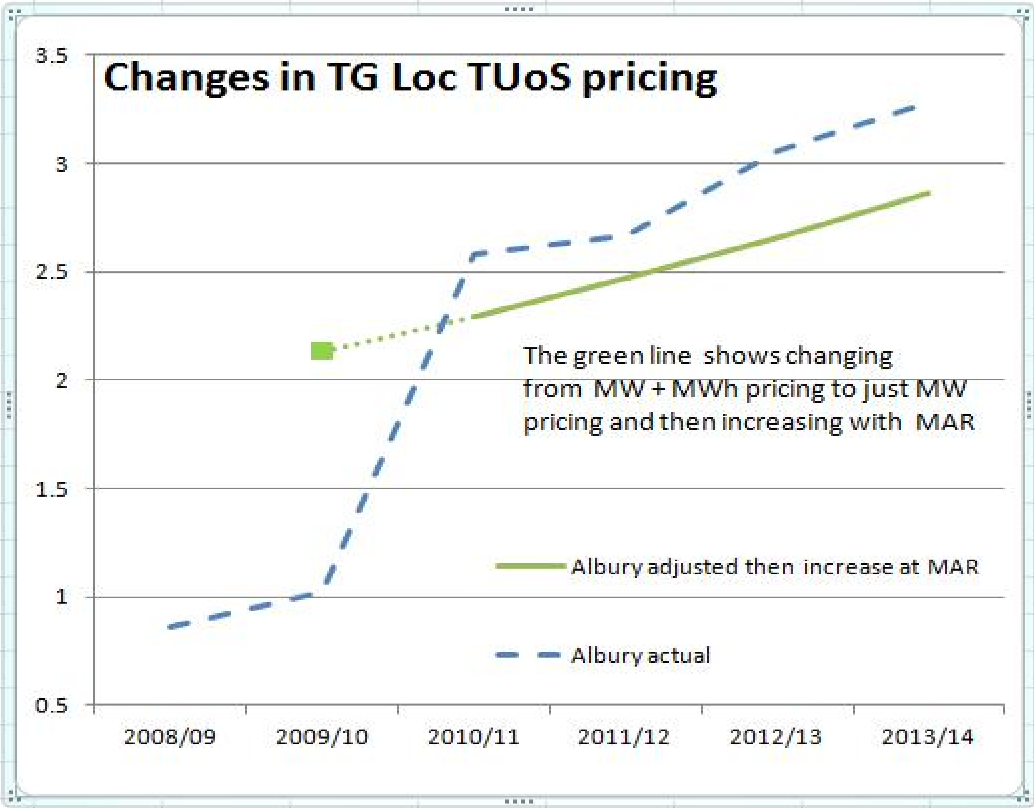
The first chart highlights a number of anomalies in the changes in prices:

- 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)[29] 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**[30] 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.

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[29] See Transmission pricing rules for definitions of CRNP (cost reflective network pricing) modified CRNP

[30] 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[31].

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 whether this provides adequate price signals to reasonably equate to long run

[31] 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.

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[32] 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.

[32] 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 consistency of pricing approach across the NEM yet the flexibility

		currently provided to TransGrid in setting transmission prices? If not, what changes would you propose?	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 appropriate? If not, what changes would you propose?**	No. See response to Q4

	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[33]) 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[34]. 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. 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.

[33] 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.

[34] 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.

			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.