*ENERGY USERS COALITION OF VICTORIA*
2-3 Parkhaven Court
Healesville, Vic, 3777
Ph: (03) 5962 3225
Email: davidheadberry@bigpond.com

24 November 2013

Mr Warwick Anderson
General Manager
Network Regulation Branch
Australian Energy Regulator
GPO Box 3131 Canberra ACT 2601 3001

By email: AEMOdetermination@aer.gov.au

Dear Mr Anderson

**AEMO electricity transmission determination**

**Proposed Pricing Methodology**

The Australian Energy Market Operator (AEMO) is responsible for providing shared transmission services in Victoria. As the coordinating electricity transmission service provider for Victoria, AEMO effectively passes through to consumers the costs for providing the transmission services provided by others (viz SP Ausnet and Murraylink) but adds to this the costs for augmenting the Victorian transmission network, planning and operating it.

The Energy Users Coalition of Victoria (EUCV) is an affiliate of Major Energy Users, Inc. and has already provided its views to the AER on the application by SP Ausnet for its allowed revenue for providing the bulk of the Victorian electricity transmission services. EUCV affiliate - the Energy Consumers Coalition of SA (ECCSA) previously provided its views to the AER on the allowed revenue for Murraylink.

As coordinating TNSP for Victoria, AEMO has to provide a methodology for pricing the provision of the transmission service to consumers and AEMO is required to obtain approval of its pricing methodology from the AER. This letter provides the views of EUCV on the approach to pricing of electricity transmission services and how these should be structured. In making the following comments, the EUCV 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[1].

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

## The cost drivers of the network

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 are designed to provide a high degree of cost reflectivity will therefore be based on the usage made of 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 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.

Acceptance of the basic premise (that demand is the driver of both new and historic investment and therefore should be used as the main pricing variable) then has repercussions throughout the development of the pricing methodology proposed by an NSP if pricing is to be cost reflective.

## Better cost reflectivity must be an outcome

The EUCV 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[2] 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 some other constraints within the rules which 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.

Concurrent with the assessments of establishing network pricing methodologies by network service providers, is the decision of SCER to examine ways of increasing demand side participation in the energy markets as a tool to reduce the burgeoning costs of electricity and gas. To this end, SCER sought advice from AEMC on ways

[2] 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 less than the avoided (marginal) cost for the service provision.

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.

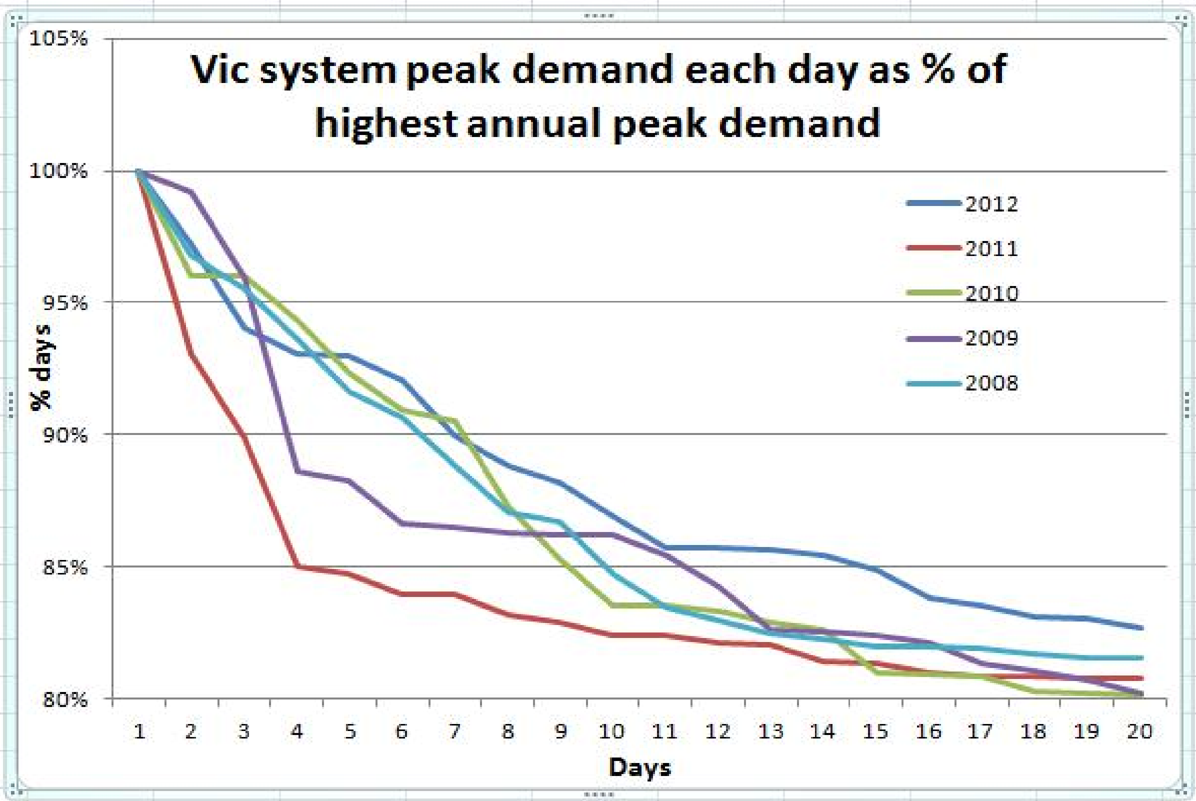
One of the most important aspects of the AEMC report is that efficient demand side participation will be increased by providing prices for network services that are as close as possible (given the constraints in the rules) to cost reflective prices. This means that accepting cost reflectivity as only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

**Costs must be shared equitably**

AEMO pricing is unique in the NEM in that it bases the prices for providing the service based on sharing the costs incurred at times when the network is most fully utilised. To this end, AEMO assesses the flows on the network by consumers on the 10 days in a year when the network is most heavily used.

The EUCV sees that this approach is cost reflective in that those consumers which 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.

The following chart shows the electricity peak system demand on the highest 20 demand days in the last 5 years in Victoria. For the sake of comparison, the lowest daily peak demand over these same 5 years averages some 50% of the peaks recorded in each year, and the average demand across all half hour periods is about 60% of the peak demand recorded in each year.




**Source: AEMO data**

The data shows that 10th highest peak demand in any year averages some 15% below the peak recorded in the year, and the 20th highest peak demand in any year is nearly 20% below the highest peak recorded in the year. This shows that demand in Victoria is quite peaky and that large demands are made on the network for a very few days in the year.

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 to the network 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).

In contrast, most other TNSPs assess the network usage for each half hour period of the year which leads to an average. The average demand on the Victorian network is about 60% of the peak demand recorded in each of the last 5 years so using this alternative allocation 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, forcing the network to be oversized.

The EUCV 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:

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

**Use of the network as a standby**

A number of consumers could provide their own generation and by doing so significantly increase the efficiency both of the energy market and nationally by increasing efficiency of energy conversion by more efficient cogeneration.

If a consumer removes itself (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 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% 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 a charge regardless of whether the usage is made when the network has spare capacity.

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 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, 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[3] and the network services priced to achieve this outcome.

On this basis the EUCV 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.

**The use of historical data for TUOS charges and common service charge**

AEMO points out that it essentially operates as a "middle man" with the assets required to provide the service being provided by others - sub-providers. Additionally AEMO only operates on a cost recovery basis and therefore must receive sufficient funding throughout the year to pay the sub-providers of the transmission assets (predominantly SP Ausnet and Murraylink). Therefore it has very limited reserves to pay out more to the sub-providers than it receives from users.

At the same time, AEMO is required to set pre-determined prices for the provision of the transmission services. Therefore AEMO must ensure that the prices set and the payments it receives from users match the payments it must make to the sub-providers.

AEMO proposes to change its approach to assessing locational TUOS charges and is seeking views from stakeholders about this revised approach.

Specifically, AEMO currently uses forecasts of maximum demand to calculate locational TUOS *prices* but then uses *actual* or contracted maximum demand to calculate the locational TUOS *charges*.[4] AEMO is now proposing to use historical maximum demands to calculate locational prices AEMO would then recalculate prices towards the end of the year to ensure the payments received for service match the outgoings AEMO is exposed to. Further AEMO appears to be seeking to

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[3] 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.

[4] Charges are based on the price * the demand at the connection point. This demand can be assessed on either a forecast or a historical basis (currently AEMO uses forecast demand)

base the charges on historic values incurred in year t-2 rather than on agreed contacted demand or actual consumption values applying for year t.

AEMO states that the benefits of this approach are twofold:

1. The calculated locational prices demand and the user charges for peak usage will be both calculated from historical data thereby limiting AEMO exposure to cash flow mismatch; and

2. The approach will remove the need for a carry over to the following year of any under/over recovery for the provision of transmission[5] that results from forecasting errors.

The EUCV is very concerned that in the current climate where consumption of electricity is declining and changes in actual peak demand are significantly less than those forecast, historical data is not a good indicator of usage in the future. Whilst the development of prices based on historic values is used in other jurisdictions, they apply prices to agreed contact demands[6] or actual consumption values to calculate the charges that apply in year t. In contrast AEMO appears to be intending to apply prices calculated on historic data (in year t-2) to values assessed from historic data (also from year t-2) to generate the charges. Whilst such an approach would be effective to over-recover revenue in a market with falling demand and/or consumption (as is currently occurring), it would under recover revenue when demand and consumption is rising (as applied up to 3 years ago).

Such an approach is contrary to the intentions of governments for consumers to drive towards greater efficiency in their usage of energy. Charging for transmission services based on historic usage might enable AEMO to be less exposed to variations between revenue and payments, but would not deliver the benefits sought by improved demand side responsiveness.

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

AEMO is seeking to use historical data for development of both its prices and charges which is many months out of date. This is because that AEMO proposes to use data recorded in full financial years yet by the time that AEMO would be calculating (and then recalculating later in the year) prices when historic data is many months (even years) out of date.

[5] Currently, the TUOS locational charges are based on the forecast maximum demand, and then AEMO subsequently conducts reconciliation with charges based on actual demand, with over and under variations repaid to or recovered from customers.

[6] Contracted demands are often set as the highest demand recorded in the previous 12 month period unless the end user has demonstrated that the forecast demand will be different due to changed circumstance

The EUCV considers that as a minimum, AEMO must use 12 month data that is the most up to date possible for the development of prices[7]. For example, if AEMO 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.

The EUCV has a deep concern that AEMO is seeking to vary prices for the later part of a year. Whilst such an approach would result in AEMO being able to "balance its books" it will impose on users very large price variations for a short period of the year.

As a matter of principle, users would prefer to see a pricing regime that applied for the entire year, with changes forecast in sufficient time for users to be able to build the new prices into their budgets for the coming year.

The EUCV notes that the AEMO approach of using historical data for both prices and charges would ensure that AEMO limits its risk of under recovery of revenue but by doing so it transfers this risk to consumers. Consumers therefore will be exposed to costs which do not reflect their actual usage of the service. This results in inefficient cost allocation and therefore is not in keeping with the Objective.

**Inclusion of known significant changes**

AEMO proposes to use historical average maximum demand data as the basis of its locational TUOS prices and charges where before it had used historical average maximum demand for locational TUOS **prices** but had calculated locational TUOS **charges** on the basis of forecast average demands or agreed contract demands for the financial year t.

The EUCV 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 EUCV considers that recent historical data is an acceptable surrogate for setting prices, with recent historical data used to set agreed contract demands for calculating charges 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 EUCV therefore supports the proposal by AEMO to provide some flexibility; for example, if there is decommissioning of significant loads or highly variable load, then AEMO may consider using forecast demand to calculate locational TUOS charges. However, it is noted that:

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[7] But not for charges which must be calculated on agreed contract demands or actual consumption

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

2. AEMO would only allow this flexibility under 'exceptional circumstances'.[8]

It is most important therefore that customers are made aware of these options for flexibility. However, it is equally important that AEMO more clearly define the circumstances in which it would be considered.

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.

**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 charges 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 EUCV and its affiliates have noted there is some inconsistency in allocation between different TNSPs in different regions.

In a similar way, the EUCV and its affiliates have seen that allocation of common services vary between TNSPs in different regions. The EUCV 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 EUCV members and members of its affiliates have varying approaches to allocation of these costs, so it is expected that there will be variance between NSPs. However, EUCV members highlight that current business practice trend is to maximise the costs incurred at "the workface" and minimise the overhead

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[8] Cited from AER Issues Paper, October 2013, p 12.

costs. If the TNSPs complied with this current business trend 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 EUCV 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, so the EUCV 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 EUCV notes that the opex used by NSPs is allocated as a common service on the basis that opex varies from location to location during a regulatory period and is therefore not specific to any element of the network. The EUCV 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 should then be recovered across the entire asset base and included in the TUoS element. The EUCV agrees that this approach is sensible.

But this argument 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 financing costs for the assets. Applying these costs to the TUoS reflects reality and would follow the same approach used to allocate depreciation.

By 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% on a locational basis and 50% 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 AEMO in this current assessment for its pricing methodology.

**Pricing approach**

The rules require the recovery of entry and exit costs to be based on a fixed charge per day ($/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.

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 EUCV finds 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 Victorian network is about 60% (ie the average demand in a year is about 60% 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% it is incentivised to pay these charges on a consumption basis whereas a user with a higher capacity factor than 60% 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% (typical of most flat load users) and the other has a capacity factor of less than 35% (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 AEMO 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.

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[9].

[9] 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 the AER continues to allow the pricing methodologies of NSPs to embed overt non-cost reflective practices, then it is allowing NSPs to set the agenda for network management which they will do to maximise their returns. The approach taken by NSPs 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, merely propagates their self interest.

**Response to AER questions posed in the Issues paper**

The EUCV has provided its responses to the questions posed by the AER in its Issues Paper in the table below. However, the commentary above provides more detail on the views of the EUCV.

| Q# | AER question | EUCV response |
|---|---|---|
| 1 | How has AEMO engaged with its customers about transmission pricing? | The EUCV was not requested to provide its views prior to the AEMO developing its views.<br>The EUCV has not been advised by its members that AEMO had contacted them on this issue.<br>The EUCV accepts that AEMO may have published a request for involvement on its website or raised the question in one of its stakeholder forums, but the EUCV does not consider that this is necessarily sufficient to obtain an appropriate level of involvement of consumers in issues that affect them. |
| 2 | What do stakeholders think about using historical maximum demand to calculate TUOS prices and charges? | As noted above, the EUCV accepts that this is a pragmatic approach to the issue, providing that known and certain future changes in demand are incorporated in the calculation of future charges (such as plant closures). |
| 3 | What do stakeholders think about using forecast maximum demand in certain circumstances to calculate TUOS charges? | See response to question 2 and comments above. The EUCV would like to see further clarity about what the AEMO considers 'exceptional circumstances'. |
| 4 | Is the process through which customers can apply to have their locational TUOS charges based on forecast average maximum demand been explained sufficiently? Are stakeholders satisfied with this process? | The EUCV understands how the locational TUoS prices are developed and then converted to charges. The use of the historical maximum demands (moderated by known changes) is supported in the development of the prices.<br>The EUCV accepts that for those users with contracted maximum demands, the application of prices on the contracted demand for the user |

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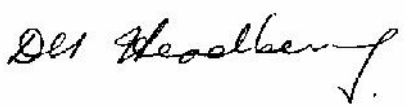
| | | develops the charges each user has to pay. To encourage users to moderate their demands at peak times as a demand side response, the EUCV considers that the locational TUoS should be calculated from the actual demand the user has on the peak system days rather the contract demand. The reasons for this view are made in the commentary above.<br>The EUCV notes that each DNSP is charged for its locational TUoS on its agreed contract demand or actual peak demand imposed by the DNSP. Just as DNSPs have to pay for their contract or peak demand in relation to locational TUoS, to be better cost reflective DNSPs should be required to pay their non-locational and common service charges based on their demand rather than on consumption. By paying on consumption, this provides a bias in favour of DNSPs and increases the costs for those paying on contract demands. |
| **5** | Are there any other changes that stakeholders consider AEMO should include in its pricing methodology? | See the commentary above on a range of issues that impact consumers in regard to pricing issues. |

The EUCV hopes that the above comments and responses are clear but if the AER or AEMO would like to discuss the points made in more detail, please contact the undersigned.

Yours sincerely



David Headberry
Secretary to EUCV
Public Officer, MEU