Major Energy Users Inc

7 December 2006

Dr. John Tamblyn
Chairman
Australian Energy Market Commission
P O Box H166
Australia Square
NSW 1215

Dear Dr. Tamblyn,

MEU Supplementary Submission on AEMC Draft Ruling on Prices

On behalf of the Major Energy Users (MEU) I would like to express our appreciation for the opportunity to discuss with the Commissioners on 30 November our views concerning the AEMC's draft Pricing Rules.

At that meeting, I explained our reasons why we consider the AEMC's draft Ruling Prices to be unbalanced and biased in favour of transmission companies.

I illustrated this by reference to the AEMC's approach which requires that consumers need only know how network prices are developed (within the wide Baumol-Willig band of avoided costs and stand-alone costs), but leaves to the TNSP's the discretion to allocate costs and determine prices that can easily bias one customer class over another. The draft Rules provide little ability to the AER to verify that TNSP's cost allocations are efficient and balanced as between customer classes.

Secondly, notwithstanding the AEMC's stated support for Rules for (economically efficient) incentive-based regulation, the draft Rules provide little or no incentives for consumers to load shed at peak usage times and limited incentives for embedded generation (whose viability is dependent on TNSP's pricing methodologies and pricing structures). Worse, there are no (efficient) locational signals to incentivise incumbent and new generators to co-locate with customer loads and/or relieve network congestion.

Against this background, you requested that we present a supplementary submission which develops the MEU's preferred pricing Rules within the framework of the MEU's goals for the review and the underlying principles that guide the MEU's approach.

The supplementary MEU submission is attached.

Yours sincerely

Mark Gell
Chairman

Supplementary Submission on the AEMC's Draft Pricing Rules

1. Introduction

The MEU welcomes the opportunity to provide a supplementary submission to the AEMC on its draft transmission pricing rules. This supplementary submission builds on the MEU's submission (dated 30 November 2006), the presentation notes (dated 30 November 2006) and the discussions between members of the MEU and the Commissioners (on 30 November 2006).

This submission develops the MEU's preferred pricing rules within the framework of the MEU's goals for the review and the underlying principles that guide the MEU's approach.

2. The MEU Goals for the Pricing Review

The MEU is seeking pricing rules for the transmission system that:-

- Is economically efficient, and delivers lowest cost possible, and is sustainable over the long term.
- Is secure, reliable and delivers reasonable quality of service.
- Facilitates a timely national electricity market.
- Grows to meet consumer needs and reduces generator market power both intra-regionally and inter-regionally.

The pricing rules should deliver economically efficient, cost reflective, incentives-based regulation by providing:-

- Economically efficient signals to incentivise investment in networks that recover reasonable costs.
- Economically efficient locational signals and incentives to incumbent and new generators, embedded generators, consumers and demand side response.

3. MEU's Principles to guide Pricing Rules

The MEU's approach to the AEMC review is guided by the following principles:-

- equity: a requirement that pricing outcomes stemming from the rules are equitable and balanced as between generators, service providers and consumers and between different classes of consumers

- cost reflectivity: a requirement that pricing outcomes are cost reflective and do not provide incentives to TNSPs to over-recover revenues/costs, and recognise the impacts all those connected to the network impose on the transmission system

- economic efficiency: a requirement that efficient signals are provided to incentivise TNSP's, generators (including embedded generators) and consumers, including demand side response, to locate and invest efficiently and to relieve congestion.

- consistency: pricing outcomes should be calculated on a consistent basis between TNSP regions (e.g. between $/MW and $/MWh, CRNP versus modified CRNP, days for cost allocation) so that investments made by users can be evaluated on the same basis

- certainty: a requirement not to provide TNSPs with wide flexibility in cost allocations and price setting, as they do not have the (business) incentive to deliver correct economic and social outcomes.

On the basis of the above MEU principles for economically efficient, incentive-based pricing regulation, the MEU consider that the pricing rules should be underpinned by the following principles:-

1. TNSPs should only recover their costs based on demand as it is demand which drives the cost of providing the service
2. The load and generation data used to develop the prices should only be based on the 10 system peak demand days, and for the 6-8 hours on those peak days when the peak is exhibited. This provides a strong basis for allocating costs to those that have caused the maximum system demands (and so the costs of providing the service), and an ability for consumers to provide demand side responses.
3. TUoS, general and common service costs should be allocated only on demand, and there should be no ability for TNSPs to recover costs on an energy basis. This reflects the costs incurred for providing the service are only related to the capacity of the network.
4. Entry and exit charges recover all of the costs associated with the substations to which users are connected. Therefore TUoS, general and common service costs should be recovered in proportion to the demand at the point where the entry/exit assets interface with the transmission lines
5. There should be no variation in the approach to price setting permitted between TNSPs

Applying the above principles in the AEMC pricing rules means:-

- ➢ Requiring point 1 above will equitably allocate the costs caused by users due to their load pattern when these demands are placed on the network
- ➢ Requiring point 2 above will encourage users to reduce their demand at times of network stress reducing the need for future network augmentation to accommodate increased demand
- ➢ Requiring point 3 above will equitably allocate costs to users based on their load pattern

- Requiring point 4 above will encourage consumers and generation to co-locate, reducing the need for future network augmentation
- Requiring point 5, allows consumers to make sensible decisions based on consistency between regions
- This provides the equity, certainty and consistency required by consumers

4. MEU's Principles and Rules Design

4.1 Consistency, certainty, cost reflectivity, equity

The current draft of the Pricing Rules permits a high degree of freedom to the TNSP to set its pricing approach to recover the allowed revenue. The draft Rule requires the AER to develop a guideline which TNSPs will be required to follow in the price setting, but as the draft Rule permits wide freedoms, the AER is not empowered to reduce this avenue for TNSP's to discriminate between generators and customers and between customer classes.

The AEMC should clearly state in the Rules that it desires the AER guidelines to be based on certain expectations.

Users need to have the same approach to pricing used by TNSPs across regions. This is an essential criterion for investment-location decision-making. This enables users to compare the expected outcome across different TNSPs. If this consistency is not a feature of the guidelines, then users are significantly disadvantaged whilst there is little compensating benefit to the TNSP which is primarily seeking to recover its allowed revenue.

Users need certainty that the prices appropriately reflect the costs incurred in providing the service, and that the costs incurred are efficient. Additionally, they need to know that there will not be changes made between resets, as the investments made by users have long term needs for certainty.

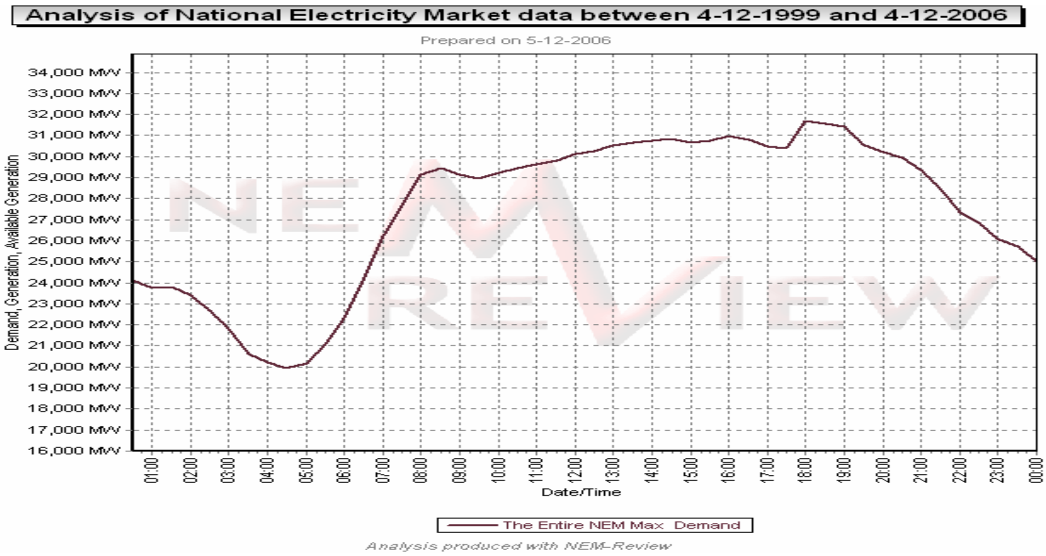
It must be explicitly stated in the Rules that there is to be equity between all users, reflecting the benefits they have and the costs incurred for the services they have.

4.2 Economic Efficiency and Demand

The Rules should require the AER to develop a guideline which is based on demand, and is to be the only basis used for pricing. Currently TNSPs allow users to pay for some services on either a demand or consumption basis whichever gives the lower cost.

Demand is the basis which sets the size of the transport assets, and therefore the costs a TNSP incurs are overwhelmingly related to the demand placed on the network by users. By allowing TNSPs the ability to price on the basis of demand or consumption does not reflect the costs involved with providing the service. This approach has an identifiable bias in favouring users that use the network occasionally, but when they do, creates the need for larger assets to be provided which are then available but unused for much of the time.

Currently there is wide flexibility available to TNSPs as to the basis for the allocation of costs. Whilst the Rules require the allocation of generator and demand flows to be calculated on a minimum number of days, there is no limit as to the maximum number of days that can be used. A number of TNSPs use the generator and demand flows for every half hour of the year, and this is equivalent to developing a cost allocation on an **average** demand basis. **Average** demand is not what drives the investment; it is **peak** demand. Therefore the cost allocation must reflect the usage made when there is maximum demand on the system. Maximum demand occurs infrequently and only during the times of midday and 8 pm as shown on the following chart, although an argument for a more accurate allocation could be made on the peak occurring at 6 pm.



By focusing attention to a fewer high system demand days and to the critical hours of those days when the maximum occurs when the peaks occur, the allocation of costs becomes much more appropriate in reflecting the costs for the service provided to users.

By addressing the allocation in this way:-

- Incentivises consumers to provide demand side responses. A consumer which reduces its demand in the critical periods when the peaks occur can receive a benefit by having an overall lower demand level on which its charges are based.
- An embedded generator (merchant or self generator) has a strong incentive to schedule its downtime for maintenance away from times when the generation is most needed (i.e. at peak demand times) to times when the demand is low.

Thus by using a demand based approach only for setting cost allocations (and therefore prices) and using only the peak times only on a set number of days when peak demands occur, is supportive of cost reflectivity, and provides incentives for embedded and self generation and demand side responses. The current approaches permitted by the Rules do not achieve this outcome – in fact they provide a clear disincentive.

Therefore MEU considers that:-

- Demand should be the only basis for pricing as it is demand that determines the value of the assets required
- Entry and exit charges, TUoS, general and common services should be recovered in proportion to demand occurring at peak usage
- Demand should be assessed based on usage on the 10 peak system demand days, and only over the 6-8 hours when this peak demand occurs
- The priority of cost allocation should reflect that any cost adjustments should be made to TUoS and G&CS charges before entry/exit charges

4.3 Point of allocation of costs

Currently the costs associated with general and common services are allocated to consumers at the point of their (i.e. consumers) connection to the network. This detracts from consumers encouraging generation to locate to nearer to the point of consumption, as there is no benefit to generators to co-locate. And consumers get no benefit from this occurring.

The AEMC requires TNSPs to allocate costs on a causer pays, and where the causer can be reasonably readily identified, then the specific causer should be allocated the cost associated with provision of the entry and exit services. This means that the entry and exit services are fully recovered by the TNSP directly from those that benefit from the service provided.

This creates two issues in cost allocation. Firstly when assets provide both an entry and an exit service, how are the costs to be allocated. Secondly at what point in the network should TUoS, general and common services be levied at.

- <u>Shared entry and exit</u>
  The Rules require entry and exit costs to be fully costed and the costs allocated to those that use the assets

  Generators most commonly generate power in the range 240v up to 22,000 volts. This means that for a generator to sell its product into the NEM there are two fundamental constraints – the capacity of the network and the need to step up voltage to the regional transmission voltage. In most cases of embedded generation the output is well less than the amount of consumption in the distribution network, i.e. the power generated by the embedded generator is absorbed by consumers connected to the distribution network. In this case the embedded generator does not need the transmission network to sell its product.

  However there are cases where the embedded generator is sufficiently large that not all its output can be accommodated within the distribution network and must use the transmission network or be constrained off. A generator of this size would most commonly be generating at 11 kV and therefore require the services of transmission entry assets to the NEM for its product to be sold. Currently the Rules permit the large embedded generator free access to transmission assets paid for by consumers in order to access the transmission system.

If the large embedded generator is provided with free step up transformation to the transmission system, then it has a benefit paid for by another party which other generators (even those connected at the same substation) do not have. Thus by the cost allocation approach used by the TNSP, the incumbent large embedded generator is not being treated with competitive neutrality in relation to other generators which are required to pay full entry costs to the transmission network, including step up transformation.

The approach should require the large embedded generator to pay its share for use of the assets if it requires access to the transmission system.

- Point of allocation of TUoS, general and common services

The Rules require entry and exit costs to be fully costed and the costs allocated to those that use the assets. Thus there are no other costs associated with the entry and exit substation which have to be recovered. This means that all other TNSP costs relate to the services to deliver or remove power from entry and exit substations.

The AEMC recognises that an element of the Pricing Rules must be to encourage generation and consumption to co-locate, as this is the most efficient (both technically and economically) approach to operating the NEM. Thus if a consumer and generator co-locate there should be an incentive to do so and a benefit should result if this occurs.

Currently the application of the Rules is that a consumer is charged its TUoS, general and common services on the actual demand it incurs at its premises, i.e. at a point remote from the entry/exit substation to which it is connected. If a generator were to co-locate suing the same entry/exit point as the consumer, this reduces the impact of the consumer demand at the entry/exit point to the substation by reducing the need for future investment, reducing losses and reducing the need for generation from remote sources.

Demand is the driver for network investment. Thus a reduction in demand at a substation due to the co-location of generation and consumption should result in users at that substation being allocated a lower share of the TUoS, general and common services as a reward for co-location. This can be readily achieved by the allocation of costs based on demand measured at the connection point between the substation and the transmission network.

TUoS will reduce as it reflects the lower flows resulting from the coincident consumption and generation at the entry/exit point. The allocation of general and common services should be equally impacted by the reduced demand at that entry/exit point.

Consider that a substation is only an exit point of supplying 50 MW. In this case the demand allocated to that substation will be the same as the demand at the points of actual consumption i.e. the consumer will pay for exit costs, TUoS, general and common services based on the demand of 50 MW. When a

50 MW generator and the 50 MW consumer co-locate, there is a net reduction in the demand at the point of connection to the network, nominally to zero. In this case there would be the full costs of the entry and exit assets paid by the generator and consumer

Under the current Rules, the consumer still pays TUoS, general and common service charges related to its 50 MW demand as if there were no generation, and the benefit of the net reduction in demand due to co-location is not recognised as the point of measurement is in the wrong place. This creates a situation where the benefit of co-location. This is an unexpected but negative outcome of the Rules and the failure to address issues from the viewpoint of consumers.

The MEU is of the view that general and common service costs should be calculated at the point where the entry/exit assets interface with the transmission lines as these costs only apply external to substations (the entry/exit points)

4.4 Allocation of IRSRs

The priority approach incorporated in the draft Pricing Rule, clearly does envisage generators sharing in the allocation of IRSRs as stated on page 39.

> "In this regard it is appropriate for generators to receive some benefit from intraregional settlement residues."

The generators in the importing region are the cause of the IRSR price differential leading to the residue, as these generators can be scheduled out of merit order in order to maintain stability in the system. The consumers in the importing region pay this premium as a result of the local generators raising prices above generators in adjacent regions (if there is no flow on the IC, there is no residue created). The consumers in the exporting region pay for their network to be sized to accommodate the inter regional export flow, yet they also benefit from the ability to import at critical times.

It is accepted that there is a needed debate as to how IRSRs should be allocated but it should be clearly stated that generators should not benefit at all from reductions in their transmission costs as a result of allocation of IRSRs. The approach in the draft Rule can allow this to occur under certain circumstances.

4.5 Prudent Discounts

There is little incentive for TNSPs to negotiate a prudent discount. There is real value in the granting of prudent discounts as the value of receiving some revenue is better for all users than the receiving of no benefit is the customer is lost – the only comment is that the discount granted should not create a revenue contribution less than the avoided cost. If the TNSP is readily able to have its lost revenue recovered from other consumers, then the loss of revenue from a user bypassing the TNSP is not an issue, and the TNSP can avoid the cost and aggravation of negotiating. The AEMC has stipulated that the value of the assets which must be bypassed before there is a penalty applied to the TNSP by the AER being permitted to optimize the asset out of the RAB is set at $20m subject to inflation. This is too high a hurdle.

A review of entry and exit charges in NSW and SA shows that a small number would be impacted by this benchmark. Of these all have large multiple loads and therefore are unlikely to be exposed to significant optimization or the likelihood of being subject to a request for a prudent discount. As most of the transmission lines have multiple users it is unrealistic to assume that these would be optimized significantly by the loss of even a significant consumer.

On balance whilst the approach suggested by the AEMC might seem to have merit, in practice the draft Rule as written will impose virtually no incentive to on a TNSP to negotiate a prudent discount.

The MEU considers that the application of the penalty with regard to negotiation of prudent discounts must be made to allow smaller users to benefit (~~ie~~i.e. the $20m asset limit is set too high). We would recommend that the value be made $2m.

4.6 Arbitration of terms and conditions

As discussed at length, it is inconsistent that whilst the price for a negotiated service should be subject to ~~arbitration, that~~arbitration that the arbitrator is not empowered to ensure that the terms and conditions associated with the price are consistent with the arbitrator ruling.

The MEU is of the view that terms and conditions for negotiated services must be subject to arbitration as is price

4.7 Priority of cost allocation

The MEU concurs that the priority of cost allocation should reflect that any cost adjustments required for revenue to come from prices the should be made to TUoS and G&CS charges before entry/exit charges

4.7 Generation

The draft Rule advises that generators are only subject to "shallow connection" costs. Because of this the draft Pricing Rules fail in a number of fundamental needs with respect to signalling the most appropriate location for new generation and equity between generation and consumers.

- Incumbent and new large generators must have efficient locational signals (to incentivise location with customers and to relieve congestion) – to rely on losses or potential congestion is insufficient incentive
- Generators should not benefit at all from reductions in transmission costs as a result of allocation of IRSRs. As it is only consumers who provide the residues, so should they be the only beneficiaries of its distribution

- Non firm generation (e.g. wind) must have efficient signals and costs allocated based on their unique load pattern and the low load factor they create

4.6 Causer pays

After much debate the AEMC determined that the principle of causer pays should be the basis for allocating costs between users of the network. Principally the AEMC used this approach to decide that generators should only be allocated “shallow connection” costs. The AEMC did not use the principle as the basis to allocate costs between different classes of consumer.

However the application of causer pays creates difficulty in resolution of congestion issues, and acts to disadvantage DSR and embedded generation (there must be efficient signals and incentive for consumers to reduce demand or self generate at times of high demand).

If the approach suggested above (i.e. using demand, and applying the approach only to a few peak system days and to the key eight hours of peak demand on those days) then the principle of causer pays does apply between consumers. Failing the approach suggested, the AEMC must identify an alternative approach to causer pays for allocation of costs between consumers.

However between consumers and generators the approach is not as clear. The AEMC has used the basis approach that as consumers need electricity, it is they which cause the need for generators to be built. This has a superficial attraction but it creates problems elsewhere. In particular it causes the problem in relation to how to address the matter of embedded and self generation which the AEMC admits is controversial and therefore it referred the issue to the MCE for resolution.

Embedded and self generation can be viewed essentially as a demand side response to reducing demand. Most embedded generation can only be commercially viable if it is associated with a consumer being prepared to underwrite some of the costs associated with it. Under the existing Rules (absent the sharing of TUoS) embedded generation suffers on two counts – it suffers due to having to pay transport of the fuel to the location of the generator, and it suffers due to economies of scale as the distribution network is often too small to be able to carry more than a modest amount of generation.

Conversely remote generation tends to be large getting benefits of scale, and it is permitted to locate near to the fuel source with consumers paying the transport of the power from the remote location to the point of consumption. This is because of the causer pays approach to allocating TNSP costs.
Causer pays allows the remote generation to locate most conveniently.

What the AEMC should have done is to addressing the supply of power from the viewpoint of the consumer as implied by the NEL objective, i.e. at the point of consumption. When a consumer places a value on alternative forms of generation (egg embedded generation located nearby suffering economies of scale and paying for delivery of its fuel, compared to a large remote generator getting economies of scale and not having to pay costs for fuel transport) the difference in the costs associated with the embedded generation and the remote generation can be identified.

Rather than follow the assumption that the consumer caused the need for power and therefore should pay for the costs for transport as well as generation, looking at the issue from the consumer viewpoint, the remote generator caused the need for the transmission network to benefit from economies of scale and closeness of fuel. This approach then allows an equitable evaluation between the two forms of generation and the costs they impose on the system. Applying this approach avoids the contentious issue of whether to incentivise embedded generation and how. Applying the approach from the consumer viewpoint eliminates the need to give any incentive to embedded generation.

The problem then becomes what happens when the embedded generation fails to supply and the consumer must draw from the NEM. If the approach to allocation is based on the generator and demand flows applying only at peak usage times, then the consumer and embedded generator have an incentive to use the network at low demand times when they do not add to the stress of the transport system. If they do use the network at peak times they incur the costs associated with providing the network.

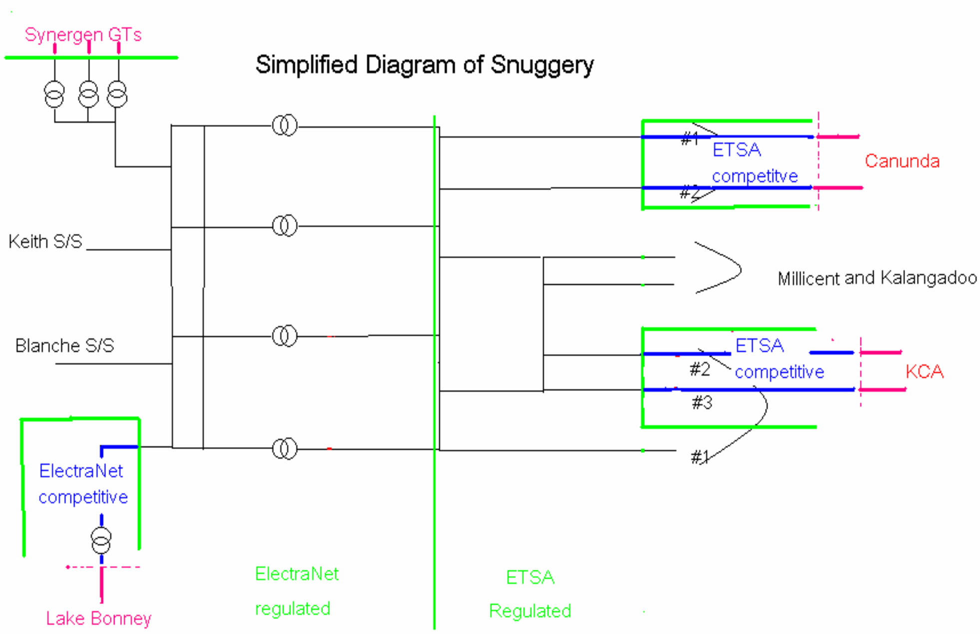
This approach also provides a clear signal to competing large remote generators – the closer they are to the point of consumption the lower the costs they incur in delivering their product to market. A new lower cost generator seeking to use the assets already used by an incumbent generator will have to ensure that its costs delivered at the point where the incumbent generator is already connected to avoid the potential of congestion which is an issue that the AEMC was waiting for a decision from the review of congestion in the NEM.

In principle, the MEU suggests that a number of difficult issues can be better addressed if the issue is addressed from the viewpoint of the consumer. We are of the view that if this is done as suggested, then issues such as embedded generation and congestion can be more clearly addressed and the concerns appear to be less contentious and vexing.

The MEU is prepared to assist the AEMC in discussing this matter in more depth, and identifying and addressing the benefits and detriments that come from the application of this approach.

4.7 Examples of actual experiences

Snuggery substation in ElectraNet's network near Mt Gambier exemplifies a number of the issues addressed in this attachment.



This simplified diagram shows the major connections at Snuggery substation. Connected at the substation are large generators (Lake Bonney and Synergen) and large embedded generator (Canunda), a large consumer (KCA) and a number of small consumers. Canunda exports more power than KCA and the other consumers guarantee to take at any time, indicating that Canunda needs access to the transmission system.

KCA gets a pass through of ElectraNet charges even though it is embedded in the ETSA distribution network. Canunda uses for step up transformation the assets used by KCA.

NEMMCo has identified that the net import of power at Snuggery is equivalent to an average demand of 11 MW, although the peak demand reaches 50+MW at times.

The issues that arise are as follows:-

a. Canunda is embedded but is not permitted to have an incentive from ElectraNet because ElectraNet charges all of its TUoS in demand. In Queensland even though Canunda is an "unschedulable" generator, it would receive an incentive payment based on the energy exported (this is a consistency issue).

b. Canunda output exceeds the demand of KCA and therefore needs access to the transmission network, but pays no entry charges to the transmission system. Both Synergen and Lake Bonney pay entry charges (this is an equity issue).
c. KCA and other consumers pay TUoS, general and common services charges based on consumption measured at their premises, rather than a share of the charges applicable to the connection point to the network reflecting the actual demand Snuggery substation imposes on the network (this is a clarity issue, and a co-locational incentive issue)
d. ElectraNet allows general and common services to be reimbursed on demand or consumption, whichever is the lower, encouraging those involved to manipulate matters to get the best outcome. This approach under recovers the costs requiring higher charges to be used than if demand only was used (this is an allocative problem)
e. ElectraNet sets its TUoS based on every half hour in the year, resulting in the average demand being used to allocate costs rather than peak demands (this is an equity problem)