MEU Inc

Major Energy Users Inc.

Australian Energy Markets Commission

DISCUSSION PAPER

National Electricity Amendment (Inter-regional transmission charging) Rule 2011

Comments on the Proposed Approach

Submission by

The Major Energy Users Inc

September 2011

Assistance in preparing this submission by the Major Energy Users Inc (MEU) was provided by Headberry Partners Pty Ltd and Bob Lim & Co Pty Ltd.

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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Executive Summary

The Major Energy Users Inc (MEU) considers that if the MCE/AEMC are still intending to introduce an inter-regional transmission charge, notwithstanding the complexities involved and the lack of clear net benefits, it wishes to reiterate some important pointers made in an earlier submission, but which are not fully debated by the AEMC's latest discussion paper:

The problems with inter-regional transmission charging

1 Any changes in usage that is caused by the introduction of inter-regional charging will impact the spot market and this needs to be taken into account

2 Introducing an inter-regional charge will not result in the lowest costs for consumers as local generation might give a lower cost to consumers than imported power when the inter-regional charge is added.

3 Consumers will have little ability to change their behaviour because their investment costs are sunk and the only effect they can make is to reduce their demand which might not affect the amount of imported power at all

4 Reliability is improved by interconnection. Thus a region which commonly exports but imports for short periods of time could get a significant benefit. Under all options that reflect the volumes of flows as the basis for charging, an outcome might be that an exporting region would receive a significant benefit which it does not pay for[1].

5 Where there are two interconnectors, (eg Heywood and Murraylink between Victoria and SA where, on average, SA imports on Heywood but exports on Murraylink) the actuality of the flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations.

6 Price signals are intended to change the behaviour of the party most able to manage the risk, yet the inter-regional charge is a cost to consumers which have little ability to manage or mitigate the risk and costs.

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[1] For example, Victoria sends bulk power to Tasmania and Tasmania sends peak power to Victoria at times when Victoria has a shortage of generation. On a volume basis, more power flows to Tasmania. In both cases (exporting and importing) Victoria gains a benefit because when it exports, it allows the large brown coal generators to run efficiently and stably so if there was less generation the costs (for technical reasons) to Victorian consumers would be higher. When Victoria imports peaking power from Tasmania it avoids having to install large amounts of peaking generation. Yet on a volume basis, Tasmanians would pay a charge to Victoria, giving Victorian consumers a considerable benefit at no cost.

Conversely any such export charge does not impinge on generator location decisions which have a major impact on the size of the export charge.

7 Options considered require a normalisation of cost allocations in all regions which might not be in the interests of consumers because a different approach used in one region might better benefit consumers in that region than the approach used in another region.

8 Because the inter-regional charge is levied purely as a transmission charge and does not reflect the delivered costs to consumers, competitive neutrality between all parts of the supply chain (eg between generators in different regions, between transmission and generation and between consumers in different regions) is put at risk.

9 Introducing a load export charge might not reflect the most efficient outcome. For example, SA has high quality wind generation locations, but the cost to transport this generation to Victoria (enabled by Victoria paying an import charge to pay for the transmission assets) will not deliver the overall lowest cost to Victorian consumers because it might be more economically efficient to build less technically efficient wind farms in Victoria where there would be no load export charge applicable. By implementing a load export charge through transmission costs that generators do not see, less efficient locational signals are provided to generators resulting in higher overall costs.

10 For price signals to provide the outcome sought, there must be consistency in both their development methodology and in the actual prices. If the actual price and impact on consumers shows significant variability year on year, then the price signal will not provide the outcome of improving location decisions of generators and consumers.

11 An inter-regional charge needs to reflect basic actualities. For example,

a. All of the costs for Basslink are paid for by Tasmanian consumers but the use of Victorian transmission assets by Tasmanian consumers is very small (Basslink connects at the heart of Victorian brown coal generators)
b. The connection between Victoria and NSW is close to the Victorian generation locus, but NSW has its generation locus remote from the Victorian border, north of Sydney. This means when Victoria imports from NSW it pays a higher charge than when NSW imports from Victorian, even though the amounts of power might be similar.

12 Perverse and inequitable outcomes are still likely even with the new approaches to this inter-regional charge.

13 The variability in costs is also a major concern especially in regions that have a large degree of weather risk (eg Tasmania in drought conditions)

14 The nominated new approaches are not supported by quantitative analysis or modelling to ascertain the economic costs and benefits. Furthermore, with the introduction of the carbon tax and increasing MRET the demand and regional inter-connector flows are likely to be very different to the current regime. Without extensive modelling and analysis it is difficult to fully evaluate approaches.

15 Whilst satisfying cost reflectivity appears reasonable the MEU questions the benefits (either in the short or long-term) given the issues and complexities inherent in the new approaches.

The principles behind a new approach

The MEU considers the approach to an export charge must:

1. Be simple and low cost to recognise the benefits are likely to be modest. If the administration costs are high in relation to the benefit provided, the concept should not proceed
2. Be based on demand not volume as the provision of the assets provided to enable the transfers must reflect the maximum demand that can be provided.
3. Recognise that the capacity of upstream/downstream assets and parallel assets defines the capability of power transfer. If the exporting region uses assets which can provide supply at a demand which exceeds the capacity of the importing region to receive the power, the question is raised should the payment to the exporting region be reduced because of inadequacies in the importing region? Equally, should an exporting region be reimbursed for the costs of assets which are significantly oversized for the ability of the importing region to receive the power? [2]
4. Incorporate only those assets provided which are excess to the needs of all intra-regional transfers. The concept implicit in the modified load export charge (mLEC – option 1) approach would seem to support the view that the value of the assets used for export is based on a "with and without" test.
5. Costs should be assessed in terms of intra-regional loads when the intra-regional loads are operating at their system peak demands. This ensures that the intra-regional costs reflect the full value of the regional network to the consumers in the region.

[2] The setting of an agreed "contract" demand would be required which might involve a third party to ensure equity is applied.

6. Exclude costs which are unique to specific regions and not a cost for the provision of power transport (eg the land tax that applies in Victoria) or adjustments (eg IRSR, over/under recovery).

Based on these principles, if an export charge must be introduced, the MEU offers for further consideration an alternative approach:

- An agreed demand is set at each interconnector both for imports and exports. This would reflect the power transfer settings used by AEMO in managing the market.
- If the agreed demand between two regions is the same on an interconnector, there would no export charge
- If there is a difference then the difference would be set as if this was the load at the border of the region with the greater ability to export.
- Identify the marginal value of the assets that are dedicated to enable the supply to this notional net load. This would be the difference in value of the assets used based on the difference between the "with" and "without" costs. The value would be assessed on a replacement basis.
- To ensure only needed assets are incorporated, the replacement costs would need to be optimised to allow only the flows that would occur to meet the agreed net demand.
- There would be an analysis carried out individually for each export point uniquely (ie without flows at any other interconnection point applying at the time).
- The assessments would be done when intra-regional flows are at a maximum so analysis over a number of peak system usage times would have to be undertaken. In the case of Victoria there might have to be four separate calculations (Basslink, NSW, Heywood and Murraylink).
- The approach would exclude extraneous costs such as the Victorian land tax, IRSR allocations, and under/overs adjustments.
- Long term stability of pricing is required, so there is a need to eliminate variations that might occur due to changes in generation dispatch arrangements[3]

However, even with this alternative there are still issues and possible unintended consequences that may arise.

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[3] For example, Tasmania's ability to provide peaking power to Victoria is constrained by the long term weather patterns (eg drought and wet weather affect the dam storages). Therefore the ability of consumers to budget and assess locational signals is compromised by such exogenous effects.

The MEU conclusions

Whilst agreeing that inter-regional charging increases cost reflectivity, the MEU strongly opposes any of the new inter-regional transmission charging mechanisms proposed on the basis that they raise additional risk and complexity with little economic value to the NEM.

The AEMC has offered three new approaches for review but the risks and complexities inherent in each are unlikely to produce material benefits to consumers overall.

As TNSP's are indifferent to an inter-regional transmission price signal, introducing such a charge is unlikely to change their behaviour in relation to their investment decisions. Equally, as generators do not see the bulk of transmission costs, they will be not be influenced to change their behaviour. End users have made their decisions based on costs that applied in the past, and as their investments are sunk, they will have little ability to change their behaviour. **This raises the fundamental questions – whose behaviour will be influenced by the introduction of an export charge and what effect will it really have?**

This proposed new rule must be considered within the context of current economic and policy circumstances facing manufacturing and trade-exposed industries that are presently operating in very challenging circumstances. The value of these investments is already being impaired due to a range of external factors which are listed in section 1.1

The MEU urges the AEMC to:

- Adopt a cautious approach to this issue,
- Assess the benefits and detriments in quantitative terms, not just qualitative terms
- Balance the benefits and downsides of such a change,
- Recognise the increase in risks to end users, and
- Consider the aggregate impacts already facing manufacturing industry which is the main financial contributor to the costs of providing electricity networks and the risks to remaining consumers should an existing large facility cease to contribute to the network costs.

Unless the AEMC can develop a better new Rule that addresses all the concerns raised in this submission, the MEU cannot support the introduction of an inter-regional export charge and recommends that the AEMC does not proceed further with this proposed new rule.

1. Introduction

1.1 About the MEU

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 are drawn from the following industries:

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

MEU members have a major presence in regional centres throughout Australia, e.g. Western Sydney, Newcastle, Albury, Gladstone, Port Kembla, Mount Gambier, Whyalla, Westernport, Geelong, Launceston, Port Pirie, Kwinana and Darwin.

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

The MEU members are mostly trade-exposed industries that are presently operating in very challenging circumstances. The value of these investments is already being impaired due to a range of external factors. These include:

1. A high Australian dollar and substantial reduction in international competitiveness;

2. High raw material input costs due to the rise in commodity prices;

3. Substantial increases in transmission charges that have already occurred and more increases are projected;

4. A substantial increase in the MRET costs due to the uncapped Small Scale Technology (SRES) target;

5. The planned introduction of a carbon tax from 1st July 2012. Even with EITE transitional assistance, the costs to MEU members will be large and will place further competitiveness pressures on trade exposed industries. In many cases this cost cannot be mitigated because either the process technology is fixed and/or investments made are largely sunk; and

6. The current EU sovereign debt concerns are weighing heavily on global markets – these macro-economic and financial risks could derail the global economy.

The MEU members are extremely wary of new costs and reallocation of costs that can lead to a further reduction of their competitive position and urges caution regarding any potential increases in risks and costs that are added to the manufacturing industry. It must be remembered that the manufacturing industry is the major contributor to network costs and a loss of this contribution will have a profound cost effect on all other electricity users.

1.2 The MEU view of the electricity market as a whole

It is necessary to put this issue of inter-regional pricing into context.

Consumers are seeing electricity costs rising very quickly, from a range of causes, such as:

- Generator market power (the AER has identified that Torrens Island Power Station in SA has market power when regional demand exceeds 2500 MW) and a significant contributor to this ability to exercise market power is that inter-regional connection is too weak
- Steeply rising transmission and distribution network prices – on average these will rise in real terms by ~50% over the next five years
- The electricity market exhibits excessive volatility in electricity prices, and as a result retailers are including in retail price offerings, large risk premiums which are causing significant retail price increases
- Implementation of the proposed carbon emission reduction program (carbon tax)
- Implementation of the expanded 20% renewable electricity target (eRET) and the small renewable (SRES) program which have significantly increased costs for electricity consumers
- The indirect costs caused by the need to augment networks to meet the outcomes of the carbon tax and eRET requirements
- Sundry other Federal and State Government renewable energy and climate change programs and 'initiatives', such as feed-in tariff schemes, climate change levies, energy efficiency programs, etc

Overall, there is a general expectation that electricity supply costs will rise in real terms by 100% or more over the next few years as a result of these changes, which are also largely driven by myriad government interventions and cost imposts in a supposedly competitive market. This is having a chilling effect on downstream investments and creating an environment where ability to pay is becoming a major issue for all consumers, ranging from large industrials facing international competition to small consumers, especially in the lowest income quintile.

There are many fundamental flaws in the current transmission revenue and pricing framework and these are likely to be accentuated by the many governmental policy interventions onto a supposedly competitive market. The MEU considers that these are clearly higher priority issues for review than the aspect of some cost re-allocation addressed by this proposed rule change. It is, nevertheless, a reflection of the very poor energy policy environment which has been created in recent years.

The development of current network charges reflect a high degree of averaging and tends to provide cross subsidies from consumers with a high load factor to those with low load factors.

1.3 The MEU view on inter-regional connectors

Interconnection between regions provides a number of benefits to consumers and to generators. Interconnection allows:

- Access to lower cost fuel sources and therefore lower cost generation for all
- Extra-regional generators to supply into adjacent regions and thereby increase competition amongst generators within a region
- Increased security of supply in the event of a major disruption in regional generation
- Short term reliability when regional demands exceed a regional ability to supply

It is recognised that essentially regionally based TNSPs are primarily interested in their own intra-regional augmentation and this has proceeded rapidly in the past decade, yet there has been no concurrent augmentation of interconnectors, even though there are strong price signals indicating such a need. The advent of the National Transmission Planner might result in greater attention to strengthening inter-regional connection but this has yet to be demonstrated.

The MEU and its members recognise that inter-regional connections in the NEM provide the basis for considering the NEM as a true 'national' market rather than a series of regions. In fact, the NEM is really a series of interconnected regions where, in the view of MEU members, there is too high a frequency of congestion on interconnectors, thereby causing regional price separation. These separations allow regional generators to use their market power to set regional spot prices at opportunistic pricing levels rather than provide consumers with pricing based on strong competition.

It is because of the impact of this opportunistic pricing of the regional market, that the MEU has consistently stated that the regulatory test for interconnectors should recognise the impact of regional price separation. The fact that no regulated interconnectors (including the unregulated Basslink which was essential for Tasmania to join the NEM) have been built or significantly augmented since QNI was built at the direction of the Queensland Government more than a decade ago, is testament to the shortcomings of the NEM and the constraints imposed on using market price signals therefore indicating a need for augmentation.

Strong interconnection between regions is essential to develop a truly national market. Currently, there is evidence that regional markets separate too frequently to assume that the five states provide a holistic market. In its assessment of the co-insurance application by NSW generators in 2010, the ACCC[4] (reflecting views submitted by the MEU) observed that:

> "With respect to the geographic scope of the relevant markets, the ACCC noted that physical constraints at the interconnectors between the regions (e.g. between Queensland and NSW) can result in congestion that may lead to significant price separation across the regions. The congestion often restricts a high demand region's ability to import electricity from a low demand region. As a consequence, prices in the high demand regions may spike or be set independently from the rest of the NEM. **In 2008-09 there was price separation 30 per cent of the time in the NEM**.
>
> The ACCC further noted that the interconnections between NSW and the Victorian and Queensland regions may experience congestion when import or export requirements exceed the respective interconnector's design limits. **The ACCC considered that this indicated that a NEM wide geographic approach to the wholesale market may not be appropriate** in considering the impact of the proposed co-insurance arrangement." (emphasis added)

The ACCC concluded that, in relation to the co-insurance scheme, the wholesale market for the supply of electricity in NSW was the NSW NEM region

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[4] ACCC Determination: Applications for authorisation lodged by Macquarie Generation, Delta Electricity and Eraring Energy in respect of a co-insurance arrangement between the electricity Generators and Gentraders in NSW, 20 May 2010, page 23

alone, supporting the MEU view that there is no NEM wide market for electricity generation.

Price signals occur frequently indicating that stronger interconnection is needed but there is a view[5] that price signals resulting from price congestion on interconnectors should be excluded from any assessment of the need for greater interconnection.

To ensure that inter-regional connection occurs for most of the time, intra-regional augmentation is also required. The benefit of strengthening interconnection between regions is significant but under the current rules, consumers in a region are required to pay for the transmission network within their region. This means that consumers in importing regions receive a "free ride" for investments paid for by consumers in exporting regions. Thus, at a basic level, the MEU considers that the implementation of a costing structure that ensures consumers in an importing region should contribute to the provision of the assets provided in another region is an appropriate approach so that the importation of power is possible.

1.4 The concept behind the proposed rule

The MEU has been a strong supporter of the principle that those that benefit from investment in the NEM should bear the cost of that investment on a cost reflective and equitable basis. This means that, **in principle**, the MEU would support allocating the costs of inter-connectors to the beneficiaries of the interconnectors, but this "in principle" support needs to reflect a number of issues which are developed in more detail elsewhere in this submission.

The MEU was a significant contributor to the earlier debates regarding the implementation of an inter-regional charge for using transmission assets in an electricity exporting regions. The MEU pointed out that the difficulties in developing an equitable inter-regional charging program could well result in other inequities resulting. In its first response, the MEU questioned whether the development efforts and subsequent administrative costs in introducing such a charge might cause (if one could be found that was equitable) would achieve a result that provides value to consumers as consumers are the focus of the National Electricity Objective. In this regard, the MEU observes the inter-regional charge would ultimately result in a reallocation of costs in that there would be no overall societal reduction of costs unless the resultant price signals were to cause a change.

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[5] This view is predicated on the concept that a transfer of wealth from consumers to generators when there is price separation does not generate a market benefit, even though it is consumers and not generators that pay for interconnection.

As all regions have sufficient generation in their own regions for the bulk of their demand, the current reason for most of the flows between regions is a result of pricing by generators. Consumers do benefit from generator competition but such competition is assessed in the absence of any network costs; there is a fundamental issue as to whether local generation is indeed lower cost than imported generation after the costs of networks and other charges are included. **In this regard, all of the options suggested by the AEMC in the discussion paper basically fail to recognise that when an inter-regional charge is added to the cost of the imported generation, will the total cost of the imported generation be less than the cost of locally produced electricity.**

For the discussion paper to address the issue of inter-regional charging purely in terms of network costs totally ignores the fact that consumers see their electricity costs in terms of the delivered price – that is the cost of electricity production plus the costs of transport. All of the options considered in the discussion paper exclude the costs of electricity production. This is a major failing of the AEMC approach to this issue.

The next question that must be addressed, is whether such inter-regional pricing signal will result in any change that will reduce overall societal costs. The discussion paper is heavy with economic theory that price signals will result in change to a more efficient outcome. In practice, if the price signal is small in relation to other costs, then it is unlikely that significant change will result. This means that rather than relying on economic theory alone, the AEMC needs to address whether the additional costs associated with its proposals will actually achieve any significant outcome. In its earlier responses, the MEU provided the view that there are many more aspects of the NEM that should be addressed in preference to devoting such a large amount of attention to an issue that is likely to achieve little change when it is implemented. This view has not changed.

The MEU has previously identified cost allocations used in transmission, where change is more likely to result in improving efficiency than the allocation of inter-regional costs will achieve. One such cost allocation is where the costs of transmission are related to peak demand, yet where prices are heavily biased towards consumption, it means consumers with high load factors will cross subsidize consumers with poor load factors. Another factor that ,generally, transmission prices reflect, is a strong bias to averaging costs, rather than sending the appropriate price signals for more efficient outcomes.

This issue of poor price signalling is considered in part in the discussion paper as an issue of inconsistency in the application of its proposed inter-regional charges. The cost allocation approach used in Victoria is seen as one where usage on peak system days is used to set prices, yet because all other TNSPs prefer to use an annual peak demand as their cost allocation approach, there is pressure to change the Victorian approach for the sake of consistency.

The final question that must be answered is to what extend would intra-regional networks be developed in the absence of inter-regional flows. There seems to be an implicit acceptance within the discussion paper that any assets used in inter-regional transfers are not required for intra-regional transport. This raises the challenge as to how to allocate the costs of assets used for both intra-regional and inter-regional transport. There is no doubt that the relative shares of each use will vary with time and magnitude. To overcome this, the discussion paper uses the flows that eventuate to reflect this differential. The drawback of such an approach is that it totally overlooks the other benefits that interconnection brings to both importing and exporting regions. On page 21, the discussion points out:

> "... interconnector assets, and further investment in such assets, provide a range of benefits to transmission customers, including reserve sharing and reliability, lower production costs and congestion, and competition benefits. These benefits apply regardless of the direction of flow"

Despite this recognition, the three options proposed in the discussion paper all ignore these benefits and so eliminate from any pricing signals aspects that provide a strong reason to support inter-regional transfers.

As a final observation, the MEU reiterates its comments made in earlier responses to this issue, that there has been very little investment in increasing inter-regional connectivity for a decade – the only significant exception to this statement was the development of Basslink, which is entirely funded by Tasmanian consumers through their payments to the government owned Tas Hydro.

Overall, whilst the MEU supports development of pricing which better reflects the costs involved with providing the service, it is concerned that the AEMC is focussing on an issue where there is likely to be a modest benefit at most. The MEU is concerned that more valuable outcomes can be achieved by using scarce resources which could be devoted to higher priority issues. Again, this is another example of the poor energy policy environment besetting the NEM.

1.5 What is the impact of this proposed rule change?

Overall, whist the principle behind the rule change has a degree of acceptability (as it should theoretically lead to greater cost reflectivity) the MEU is very concerned that the benefits that might flow from the rule change, will be swamped by the developmental and administrative costs, detriments and inconsistencies that it generates.

Despite the options considered in the discussion paper, there is still significant complexity inherent in the concept and this added complexity needs to be balanced against the potential changes that might result from the price signalling that results.

Existing consumers have made significant investments based on the current and previous structures of the electricity market. Just as the discussion paper observes that TNSPs have their assets now "sunk" and as a result they cannot be changed, so too are consumers' (considerably larger) assets sunk, and to assume that they will make change to reflect an inter-regional pricing signal, beggars belief. That the AEMC is of the view that TNSP investments must be protected and not subject to pricing signals but considers that consumer's investments will react and are mobile, is just bad and short sighted economics.

In its previous submissions, the MEU pointed out that the impact of the load export charges on large consumers on importing regions would be significant. In one way the discussion paper is correct in that inter-regional price signals might engender consumer change – but such change might be the down-sizing or closure of these large consumers thereby leaving higher transmission costs to be borne by fewer consumers, and due to rising unemployment, an inability to pay.

The AEMC must include in its assessment what the possible outcome on large consumers might be.

1.6 Basis for cost allocation

The discussion paper addresses four elements of CRNP pricing which impact on the basis of cost allocation. These are:

- 10 day system peak or 365 day peak element
- Postage stamping elements
- Measure of demand to set prices
- Valuation of assets

As a general comment, the MEU finds it amazing that TNSPs are provided with so much decision making power regarding the setting of transmission prices. A TNSP receives the same revenue regardless of the approach used to recover its costs. This means that TNSPs should be advised what approach to price setting is to be used so that the other goals of the electricity market (eg demand side signalling[6]) can be achieved. It is beyond belief that a TNSP which is indifferent to the way its revenue is recovered should be afforded so much influence to set its prices to suit itself.

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[6] The MEU notes that the AEMC is currently examining demand side participation

The MEU considers that transmission pricing should reflect and influence the decisions of consumers rather than TNSPs, as consumers are the main parties that will vary their activities to reflect the price signals that the electricity market is supposed to send.

The following sections discuss each of the four headings.

1.6.1 10 or 365 day peak

As network sizing is directly related to peak demand, peak demand should be the basis on which pricing is set. It must also be recognised that the system peak demand occurs for a few hours each year but this becomes the basis for a regional network design[7]. To set a value of assets based on flows does not recognise the asset is built to match the peak demand.

The 10 day approach is designed to reflect the conditions that drive the bulk of the investment in the network and the amount of investment needed. The MEU does not consider that the actual demands should be monitored over the entire day on which the peak demand is recorded, but should be the relatively few hours when the peak demand actually occurs. This reflects the actual usage of the network best, although it is conceded that specific network elements may have a higher demand on days other than the peak system demands. Both approaches have drawbacks, but using the peak demands that actually do occur is more likely to provide a more equitable basis for cost allocation than other approaches.

It is important to recognise that pricing is not an exact science and in the development of pricing, many assumptions are made and averaging applied. What results is an outcome which balances accuracy with ease of application.

One of the major benefits of using the few system peak hours in a year as the basis for measuring individual demands is that it provides a strong signal for demand side participation for demand management[8] and this approach also tends to align better with the wholesale market price signal as this does not occur with either the AEMO 10 day or the 365 day approaches.

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[7] In fact, a network is designed to a higher peak demand. As a general rule, the network is expected to accommodate the peak demand which would occur if the peak demand was more than that forecast at the level of 10% probability of exceedence.

[8] This is an issue being addressed by the AEMC DSP 3 review currently in train

The discussion paper notes that a disadvantage of the 10 day approach is that individual element peaks may occur at other times. This is true, but this is unlikely to occur for every one of the time periods used to identify the peak usage. Another disadvantage noted is that there is an ability to select the days used. This is readily overcome by allowing only times when the system peaks occur to be used – these are driven by consumers and not the TNSP. That only AEMO uses this approach reflects that other TNSPs have not addressed the issue preferring to retain the approach used before the NEM was developed.

The MEU considers that the hours when the system peaks occur, should be the basis for determining peak demands for cost allocation purposes. The benefits of such an approach is that it is more likely that these will coincide with the wholesale market price peaks providing a stronger demand side participation incentive (especially as the demand side has a better appreciation as to when to contribute to the market) and it better allocates costs reflecting actual investment.

1.6.2 Postage stamping elements

The rationale for separating common services from locational signals is that there is no easy way to allocate such costs on a locational basis. Equally, common services are required to be provided by the regional TNSP regardless of whether there is export or not, so consumers in a region are liable for these regardless of the amount of export.

Non-locational TUoS charges are also postage stamped and the rationale for setting the amount to be the same as the locational TUoS is not explained in the AEMC transmission pricing documentation, although observations have been made that non-locational TUoS being postage stamped reflects the "sunk nature" of the transmission assets. Once set, the amount for recovery as non-locational TUoS includes over and under recovery of the ASRR[9] the previous year and the allocation of the IRSR[10] so that the non-locational TUoS amount varies considerably year on year.

Because of the development of the non-locational TUoS, it does not fully reflect the value of the assets used in association with exporting of power, and it includes amounts that should not be allocated to consumers in power importing regions. Essentially, as with the common services, the non-locational TUoS is a cost that consumers within the

[9] Annual Service Revenue Requirement

[10] Inter Regional Settlement Residue

exporting region would have to pay regardless of whether there was an export or not.

Both non-locational TUoS and common service charges can be recovered on either a demand ($/MW) or consumption ($/MWh) basis, depending on which calculation gives each user the lower cost[11]. This could result in the transmission export charge under or over-recovering the actual cost reflectivity involved, as well as some of the benefits resulting from the importation of power caused by the ARSR and earlier over/under recovery of revenues.

These factors indicate that neither the non-locational nor the common service charge should be included in an export charging approach.

Locational TUoS is developed to provide a locational signal and is therefore charged on a demand ($/MW) basis. To a degree such an approach if applied as an export charge would reflect the cost of the assets provided to export power to an adjacent region. Using this alone would reflect an export charge even if it were used only once a year. This would create anomalies in relation to both volumes of exports and the location of generation.

In the first case, if the demand from one region to another was the same, but the volume of flows was heavily in one direction then the export charge element based on the locational TUoS would be indifferent to the volumes of the flows. In the second case, the more remote the generation locus is from the interconnector in the exporting region, the greater the cost of the locational TUoS.

The anomalies can be exemplified in the case of flows between Victoria and Tasmania. The demand in either direction on Basslink is the same yet there is a net flow from Victoria to Tasmania. As the demand is identical, there is no net transmission export benefit to Victoria by sending large flows into Tasmania. However, the connection of Basslink in Victoria is adjacent to the generation locus in Victoria (at Loy Yang) so the locational TUoS for Basslink is quite low. In contrast, the generation locus in Tasmania is across the north and west of Tasmania, necessitating a large locational TUoS to serve the south end of Basslink. This means that although Tasmania is a net importer of power the allocation of locational TUoS changes in the export charge would require Victoria to pay Tasmania.

[11] This is in contrast to locational TUoS which must be recovered in terms of demand (ie $/MW)

Postage stamping of locational TUoS would tend to overcome such an anomaly but this would necessitate a total revision of the pricing structure on an intra-regional basis.

Issues, such as the inclusion of land taxes in TUoS charges, further complicate setting equitable export charges.

1.6.3 Measure of demand

To a degree this issue is addressed in section 1.6.1. The fact that TransGrid set its maximum demand on a monthly basis does not reflect the extent of the assets used to meet the annual peak demand. The MEU considers that setting demand usage at the times of the system peak provides a much more accurate basis for sharing costs than any of the approaches used by any TNSP (including AEMO and TransGrid).

1.6.4 Valuation of assets

The discussion paper notes that assets are valued on an ORC[12] basis. This is not strictly true as the requirement to optimise asset values was removed in the development of Chapter 6A rules, as actual capex is now automatically rolled into the asset base. Each TNSP develops its own methodology for price setting and this is assessed by the AER at each revenue reset review. There is no requirement for each TNSP to use the same approach, providing the approach proposed meets certain basic parameters.

The MEU agrees with the discussion paper conclusion that a common approach is ideal but notes there maybe unintended consequences from such an approach because each region might need some differences to suit the particular region's needs.

1.7 Capability of transfers

It is recognised that assets in an exporting region might be sized to enable a greater inter-regional transfer than the importing region is capable of receiving. The reasons for this incapability might be because of a weaker intra-regional transmission network (eg flows from SA to Victoria via Murraylink are often constrained because of the inability of the Victorian region network design to accommodate the full capacity[13]) or because generators locate close to the inter-regional connection point, reducing the capacity for inter-regional flow (eg

[12] Optimised replacement cost

[13] In the ACCC decision to regulate Murraylink, part of the decision required augmentation of the Victorian network if the full capacity of Murraylink was to be realised.

the decision to build Lake Bonney wind farm where it connects to the SA network constrains the Heywood interconnector when Lake Bonney is generating).

This means that one region, with both the ability to import and export, has the ability to construct its network in such a way that could force a second (importing) region to receive more import flows compared to the second region's ability to export to the first region. Such an approach would impose costs on the importing region that are not caused by the importing region or for it to be able to operate in a way that mitigates the export charges that might be imposed.

1.8 Conclusions

Whilst allocating inter-regional charges is to provide a price signal to engender change so there will be a societal benefit, it is important to identify whether such a signal would result in an overall benefit.

Who are the parties that will be affected by the introduction of an export charge?

- TNSP's are indifferent to an inter-regional transmission price signal, introducing such a charge is unlikely to change their behaviour in relation to their investment decisions, and yet TNSPs and AEMO (as the NTP) will incur considerable costs to develop the price signal.
- Generators (who only see shallow transmission connection costs) do not see the bulk of transmission costs and will not see the export charge, so they will be not be influenced to change their behaviour.
- End users have made their decisions based on costs that applied in the past, and as their investments are sunk, they will have little ability to change their behaviour. Essentially those end users which see an increase in cost as a result of the export charge, have only one option to manage the cost increase by ceasing to use electricity, which adds to the costs for all other consumers.

This raises the fundamental questions – whose behaviour will be influenced by the introduction of an export charge and what effect will it really have?

After devoting significant time and analysis to the issue of an export charge, the MEU considers that introducing an export charge provides a massive increase in complexity and risks for all. On deeper analysis it is clear there will be so little of benefit to be achieved from it in relation to its cost of implementation, but there is potential for great harm to eventuate.

2. An overview of the issues previously raised by the MEU

In its previous submissions, the MEU pointed out that whilst it accepted the principle of cost reflectivity in transmission charges (including the proposed inter-regional charge), it also identified that there are more impacts of interconnection than the proposed approaches give regard to. The MEU considers that any changes to introduce inter-regional charging must recognise:

1 Any changes in usage that is caused by the introduction of inter-regional charging will impact the spot market and this needs to be taken into account.

2 Introducing an inter-regional charge will not result in the lowest costs for consumers as local generation (not dispatched because its price is marginally higher than generation in an adjacent region) might give a lower cost to consumers than imported power when the inter-regional charge is added.

3 Consumers will have little ability to change their behaviour because their investment costs are sunk and the only effect they can make is to reduce their demand which might not affect the amount of imported power at all

4 Reliability is improved by interconnection. Thus a region which commonly exports but imports for short periods of time could get a significant benefit. Under all options that reflect the volumes of flows as the basis for charging, an outcome might be that an exporting region would receive a significant benefit which it does not pay for[14].

5 Where there are two interconnectors, (eg Heywood and Murraylink between Victoria and SA where, on average, SA imports on Heywood but exports on Murraylink) the actuality of the flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations.

6 Price signals are intended to change the behaviour of the party most able to manage the risk, yet the inter-regional charge is a cost to consumers which have little ability to manage the risk. Conversely any such export

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[14] For example, Victoria sends bulk power to Tasmania and Tasmania sends peak power to Victoria at times when Victoria has a shortage of generation. On a volume basis, more power flows to Tasmania. In both cases (exporting and importing) Victoria gains a benefit because when it exports, it allows the large brown coal generators to run efficiently and stably so if there was less generation the costs (for technical reasons) to Victorian consumers would be higher. When Victoria imports peaking power from Tasmania it avoids having to install large amounts of peaking generation. Yet on a volume basis, Tasmanians would pay a charge to Victoria, giving Victorian consumers a considerable benefit at no cost.

charge does not impinge on generator location decisions which have a major impact on the size of the export charge.

7 Options considered require a normalisation of cost allocations in all regions which might not be in the interests of consumers because a different approach used in one region might better benefit consumers in that region than the approach used in another region.

8 Because the inter-regional charge is levied purely as a transmission charge and does not reflect the delivered costs to consumers, competitive neutrality between all parts of the supply chain (eg between generators in different regions, between transmission and generation and between consumers in different regions) is put at risk.

9 Introducing a load export charge might not reflect the most efficient outcome. For example, SA has high quality wind generation locations, but the cost to transport this generation to Victoria (enabled by Victoria paying an import charge to pay for the transmission assets) will not deliver the overall lowest cost to Victorian consumers because it might be more economically efficient to build less technically efficient wind farms in Victoria where there would be no load export charge applicable. By implementing a load export charge through transmission costs that generators do not see, less efficient locational signals are provided to generators resulting in higher overall costs.

10 For price signals to provide the outcome sought, there must be consistency in both their development methodology and in the actual prices. If the actual price and impact on consumers shows significant variability year on year, then the price signal will not provide the outcome of improving location decisions of generators and consumers.

11 An inter-regional charge needs to reflect basic actualities. For example,

  a. All of the costs for Basslink are paid for by Tasmanian consumers but the use of Victorian transmission assets by Tasmanian consumers is very small (Basslink connects at the heart of Victorian brown coal generators)
  b. The connection between Victoria and NSW is close to the Victorian generation locus, but NSW has its generation locus remote from the Victorian border, north of Sydney. This means when Victoria imports from NSW it pays a higher charge than when NSW imports from Victorian, even though the amounts of power might be similar.

These points were all made in previous responses to the AEMC regarding this issue and rather than reiterate these previous submissions, the MEU directs the AEMC to accept these points as made and to review these to understand the arguments made in support of the points made. The MEU is very concerned that these issues have not been fully debated in the AEMC's latest paper, nor have these issues been incorporated into the options discussed by the AEMC's paper.

In addition to the formal submissions the MEU made to the AEMC, it had discussions with AEMC staff that were confirmed in email exchanges. These email exchanges (with comments not related to the issue being deleted) are provided as appendix 1.

Although the principle which underpins the concept of an inter-regional charge is, prima facie, a simple and supportable one, when the implications are examined in more detail, there is a clear need to identify in the rules, the basis on which such an allocation of the costs must be made, and to eliminate anomalies that it will cause in terms of unintended transfers of benefits and detriments between regions. It must be remembered that the purpose of a load export charge is to send locational signals to achieve an outcome, as well as to provide cost reflectivity. If these outcomes are not achieved, there is little value in expending effort in the development.

The MEU considers that the complexity of implementing the proposal might reach a level where the value of the proposal has only a marginal benefit compared to the costs of implementation and the degree of moving from the relative simplicity of the current arrangements. The MEU also sees that, inevitably, to manage the complexity simplifying assumptions will have to be made which will result in the concept providing much less benefit than is anticipated.

3. Three options proposed by AEMC

In the discussion paper the AEMC proposes three basic options for discussion to identify if any have the potential to address most of the concerns raised by stakeholders to previous proposals. These three are:

1. Modified load export charge
2. Cost sharing
3. NEM wide CRNP

The MEU provides its views on the concepts behind each of these three options and then responds to each of the AEMC initiated questions in the following section.

3.1 Modified load export charge (mLEC)

The MEU has previously advised its views on the original load export charge (oLEC) and pointed out that the approach would result in significant harm. In the discussion paper, the AEMC notes that (pages 18 and 19):

> "The cost impacts of the original LEC [oLEC] were modelled in a way that identified disaggregated prescribed locational TUoS, non-locational TUoS and common transmission services charges. These were based on each TNSPs' own methodologies. Based on the inclusion of prescribed non-locational TUoS service charges, it was found that customers in NSW and Tasmania would be net payers of the original LEC, though in each case the increase in a small customer's bill in those regions would be less than 1%. However, the cost increases for larger customers have not been assessed. Some submissions suggested that this could be considerable if the prescribed non-locational TUoS service component is included in the charge. Nevertheless, those costs may be justified if the intention of the charge is to encourage more efficient locational decisions with respect to ensuring efficient investment in inter-regional transmission over time. Based on internal modelling these figures would change if the prescribed non-locational TUoS service component was removed, such that Victorian customers would become the only net payers in the NEM, with the total net impact in Victoria of approximately 5% of Aggregate Annual Revenue Requirement (AARR). The actual cost impacts would depend on the exact composition of the inter-regional charging methodology adopted."

The MEU is very concerned about a number of comments in this statement.

Firstly, the oLEC as calculated has a number of basic flaws embedded within it, such as the Victorian land tax and a number of other aspects discussed in earlier submissions on this topic making it essentially inequitable.

Secondly, the impact on large consumers was measured in terms of $millions adding considerably to their operating costs. They cannot be lightly dismissed.

Thirdly, the AEMC notes that such "... costs might be justified if the intention ... is to encourage more efficient locational decisions ..." What the AEMC totally overlooks is that these large consumers have made locational decisions based on earlier cost structures and as their assets are now sunk, to relocate is not an option. The AEMC has previously decided that as TNSPs assets are sunk, they should not be required to optimise or bear the costs for assets no longer used. To assume that a different pricing environment will cause consumers to relocate is purely fanciful. The only outcome would be for those consumers to cease operations. There is inconsistency in this type of reasoning by the AEMC.

Fourthly, it would be anomalous for Victoria to be the only region paying a LEC under a locational TUoS only basis as Victoria is a net exporter of power to all of the regions adjacent to it. This would be tantamount to Victorians paying for the privilege to be an exporter!

The AEMC proposes a modified load export charge (mLEC) for consideration. From the description provided and the approach used, it appears that the mLEC would become an assessment of the marginal cost to provide exports. In principle, the MEU would support such an approach and it reflects a concept the MEU provided in its response to the AEMC draft rule in February 2011. In that response the MEU commented (page 5):

> "The MEU believes that a more equitable system might involve the calculation of the LEC to be based only on those assets specifically used in exporting power and for the marginal costs to be allocated in terms of demand on those assets when the region is operating at its peak demand. This recognises that many of the costs an exporting region incurs are totally unrelated to any export of power and, therefore, should not be allocated to an importing region."

The MEU still considers that this approach has merit, but it suffers (as does the mLEC) from those other shortcomings identified by many submitters and detailed above (such as the land tax issue and more fully explained in sections 1 and 2 above).

The discussion paper quite rightly highlights that the mLEC as calculated between adjacent regions actually could result in further anomalies. The example of where region A provides power to region C but transfers this through region B is a case in point and the MEU agrees that there is potential for region B to either under or over recover its costs purely for being an intermediary. To be fair, region C could only receive a benefit due to region B providing transit capability but the relative locations of the generator loci in each region would provide some distortion of an equitable outcome for all regions involved.

The main benefit of the mLEC over the oLEC is that is seems to address the issues that the difference in assets needed within a region should be paid for by that region, and the only cost that an importing region should pay is related to the additional cost an exporting region has to incur so that power can be exported.

From the MEU point of view the mLEC suffers from a major flaw in that it does not reflect the value each region is provided in terms of increased reliability and security or to reflect the value of generation in an adjacent region. This point was made in the MEU response to the AEMC consultation paper (even though the AEMC again remained silent on the issue) where the MEU commented (page 11):

> "However, the [LEC] approach does not appear to reflect the importance of any power flows at any given time.
>
> Such small flows could be for overcoming reliability issues or to offset a large spot price change, where the small flows are in one direction for short periods but which have a massive impact on consumers in the importing region to avoid blackouts or large transfers of wealth between consumers and generators in the importing region. Flows in the other direction might be much greater in aggregated volume, but have a minor impact on consumers in the other region."

Another major drawback of the mLEC is that it still is based on net flows between regions and is not based on the costs to provide for the peak demands which are the drivers of investment in a network[15].

In the discussion paper AEMC notes that the mLEC would result in:

- Benefits to consumers in the exporting region which would not be paid for. The AEMC notes that these benefits provide value to both an importing and an exporting region and therefore there is no need to recognise these costs. The MEU disagrees with the AEMC on this point as discussed in section 2 above and in earlier submissions. The value to one region to have peaking power available may exceed the value to a region to have slightly lower priced bulk generation.
- Recognition of the net flows of electricity transferred. The MEU points out transmission assets are sized to reflect peak demands and not the

[15] This is also a flaw in the setting of non-locational TUoS within a region

volume of flows. To allocate a charge based on flows does not reflect the cost the exporting region devotes to enabling the peak demand the importing region imposes on the exporting region. To use any other measure than demand biases the mLEC allocations away from reflecting the actual costs incurred in providing the ability to export. It requires an exporting region the same to export 600 MW for one half hour as it does to export 600 MW continuously.

- A mLEC will be administratively complex to manage, both from the time involved and to impose consistent methodologies. The MEU agrees with the AEMC in this regard
- An mLEC will result is considerable volatility and thereby reduce the value of the price signal The MEU agrees with the AEMC in this regard

3.2 Cost sharing

The concept behind the cost sharing approach appears to be the defining of those assets used to carry the bulk of inter-regional flows – effectively identifying the "spine" of the NEM and excluding the intra-regional network which delivers power to the various load centres within each region. Such an approach would deliver an approximation of the national network and this provides some attraction for the concept as it provides the basis for development of a truly national network where needed augmentations of interconnection capability can be clearly identified.

One major benefit of such an approach is that it does provide some recognition that improved reliability and security result and that costs of this provision are shared by all consumers. The discussion paper identifies that these broader benefits would be considered as part of any RIT-T assessment, but this could only apply to new augmentations, limiting its application for existing assets.

There are some drawbacks which would need to be addressed, including:

- Power flows use more assets than just the "spine" of the NEM. This means that the carrying capability of the "spine" is limited by flows within parallel paths that would be embedded in the intra-regional networks. The implications of this are that to increase the carrying capacity of the spine, augmentation in the parallel flow paths might be needed rather than work on the spine. Augmentation of the parallel flow paths also increases the capacity of intra-regional flows which should be a cost to consumers within the region and so this has the potential for consumers in other regions to contribute to intra-regional network augmentation.
- Such an approach does not provide locational signals to generators and consumers of the impact of their decisions.
- The approach to allocation of costs would be fraught, with the potential for consumers in a region which provides "transit" (ie the ability to flow

power from one region to a non-adjacent region) would carry costs for assets that they do not use or benefit from.

- The approach does not address the problem of cost allocation based on demand versus volume. Should consumers pay in proportion to the demand they impose occasionally (which sets the value of the assets) or on the volume of the flows which has little bearing on the cost of the assets used? As noted above, the MEU considers that demand should be the basis for cost allocation.
- The approach does not recognise that even though the assets might be provided but not used (ie there is no flow) there will be a cost to provide the assets that are lying idle
- In the case of some interconnection assets (eg Murraylink and Directlink) these assets have to be assessed whether they are or are not part of the national "spine". In reality, they only connect elements of the intra-regional transmission assets in different regions and their carrying capacities are severely constrained by the capacities of the intra-regional networks in each region.
- The large proportion of the assets comprising the "spine" to enable trade between regions are mainly located in NSW and Victoria and these assets are also used for intra-regional transport of electricity. A key issue will be to assess the proportion of the value of the assets between inter-regional transfer and intra-regional needs so that SA, Queensland and Tasmanian consumers do not incur costs that are rightly costs for consumers in Victoria and NSW.

The MEU considers that the cost sharing option needs to be more carefully considered than is currently included in the discussion paper. As noted above, there are some considerable drawbacks to this option although it has some features which make it more attractive than the LEC option. A clear delineation is needed to identify the assets comprising the "spine" and how to allocate the costs equitably across all consumers.

As with the LEC, the MEU considers that allocating costs based on demand is a more appropriate approach but with the cost sharing option, this approach is unlikely to deliver equity to all.

3.3 NEM wide CRNP

The NEM wide CRNP approach combines some of the features of the LEC approach with some of the cost sharing approach. The challenge for the NEM wide approach is to identify which assets are used for inter-regional transfers and what extent. It would seem from the description provided, that assets providing parallel flows would be included in the NEM wide approach, further complicating the calculations.

As with the LEC approach, it is based on power flows and as discussed above, this eliminates the benefits that consumers get in terms of improved reliability and security as a result of interconnection. Being based on load flows, it does not recognise that occasional imports require provision of the same assets as continuous import at the same demand. It does have the advantage of recognising the costs and benefits a non-adjacent region might incur.

To eliminate the need for every TNSP to comply with a standard approach to price setting (and allow individual TNSPs an appropriate flexibility to address price setting to suit its specific needs), it would be most appropriate to use a standard approach and this would be best achieved by AEMO in its role as the national planner. However, this will create a need to duplicate all the work done by each TNSP and it would be necessary to establish whether the program used by all TNSPs to set their prices (T-Price) had the ability to manage such a large dataset as would occur if the cost setting approach is to be addressed on a NEM wide basis.

As the outcome is likely to be a relatively modest cost reallocation and one which will still be beset by averaging, it raises the question as to whether the exercise delivers a benefit that outweighs the costs involved. Any national pricing regime may present greater risks to consumers as they will be a smaller part of the larger picture. Until there is certainty of the benefits of such an approach (and that these benefits are material and outweigh the risks) the MEU is not convinced that such an approach should be implemented.

As with the mLEC proposal, the MEU does not consider that the outcomes from a NEM wide CRNP approach will overcome the significant disadvantages and inequities that apply to either the mLEC approach or the cost sharing approach.

3.4 Conclusions

Overall, the MEU does not consider that any of the three new options proposed reduces the risks or complexities inherent in deriving an export charge, to a level that makes them viable options for further consideration.

The MEU considers that they have the same unacceptable outcome as the original export charge proposal, but at significant cost. The basic concept is to provide better signalling in the market. TNSPs and generators are essentially indifferent to the signals but an export charge based on the four options considered (the MCE option and the three new AEMC options) all introduce a much greater potential to harm end users than any benefit it might provide to them.

4. An alternative approach

The MEU has concluded that implementing an export charge for inter-region transfers is quite complex and beset by challenges in trying to balance significant competing issues. It is extremely concerned that in attempting to develop an export charge, significant harm may occur as inequities are inevitable. In this regard, the MEU is very concerned that the values of its members' very large investments are not impaired by theoretical assumptions and assertions about charges being necessary to achieve "efficient investment".

At the same time, there will be significant transaction costs and drivers to create commonalities of approach that might not be in the best interests of consumers.

Overall, the MEU has concluded that despite supporting the concept of increasing cost reflectivity in inter-regional power transfers, there are major difficulties in developing a better solution than that which currently applies. At the same time, the MEU considers there are greater problems in getting better cost reflectivity right across the transmission and network pricing approaches than inter-regional trades. This lack of cost reflectivity endemic in all intra-regional network pricing creates greater problems in achieving the aims of the electricity objective than does the potential of improving cost reflectivity in inter-regional trades.

If there must be export charges, the MEU considers there are some basic concepts that must apply to the setting of inter-regional charges for transfers or power.

The MEU considers that any approach must:

1. Be simple and low cost to recognise the benefits are likely to be modest. If the administration costs are high in relation to the benefit provided, the concept should not proceed
2. Be based on demand not volume as the provision of the assets provided to enable the transfers must reflect the maximum demand that can be provided.
3. Recognise that the capacity of upstream/downstream assets and parallel assets defines the capability of power transfer. If the exporting region uses assets which can provide supply at a demand which exceeds the capacity of the importing region to receive the power, the question is raised should the payment to the exporting region be reduced because of inadequacies in the importing region? Equally, should an exporting region be reimbursed for the costs of assets which are significantly oversized for the ability of the importing region to receive the power? [16]

[16] The setting of an agreed "contract" demand would be required which might involve a third party to ensure equity is applied.

4. Incorporate only those assets provided which are excess to the needs of all intra-regional transfers. The concept implicit in the modified load export charge approach (option 1) would seem to support the view that the value of the assets used for export is based on a "with and without" test.
5. Costs should be assessed in terms of intra-regional loads when the intra-regional loads are operating at their system peak demands. This ensures that the intra-regional costs reflect the full value of the regional network to the consumers in the region.
6. Exclude costs which are unique to specific regions and not a cost for the provision of power transport (eg the land tax that applies in Victoria) or adjustments (eg IRSR, over/under recovery).

Based on these principles, the following alternative approach is offered for further consideration:

- An agreed demand is set at each interconnector both for imports and exports. This would reflect the power transfer settings used by AEMO in managing the market.
- If the agreed demand between two regions is the same on an interconnector, there would no export charge
- If there is a difference then the difference would be set as if this was the load at the border of the region with the greater ability to export.
- Identify the marginal value of the assets that are dedicated to enable the supply to this notional net load. This would be the difference in value of the assets used based on the difference between the "with" and "without" costs. The value would be assessed on a replacement basis.
- To ensure only needed assets are incorporated, the replacement costs would need to be optimised to allow only the flows that would occur to meet the agreed net demand.
- There would be an analysis carried out individually for each export point uniquely (ie without flows at any other interconnection point applying at the time).
- The assessments would be done when intra-regional flows are at a maximum so analysis over a number of peak system usage times would have to be undertaken. In the case of Victoria there might have to be four separate calculations (Basslink, NSW, Heywood and Murraylink).
- The approach would exclude extraneous costs such as the Victorian land tax, IRSR allocations, and under/overs adjustments.
- Long term stability of pricing is required, so there is a need to eliminate variations that might occur due to changes in generation dispatch arrangements[17]

[17] For example, Tasmania's ability to provide peaking power to Victoria is constrained by the long term weather patterns (eg drought and wet weather affect the dam storages). Therefore the ability of consumers to budget and assess locational signals is compromised by such exogenous effects.

The MEU sees that the alternative approach also introduces inequities and approximations but does provide significant simplification compared to all the other options.

This alternative approach, like all of the other options considered, does not make adjustment for the fact that a major issue is that the location of the generator loci in each region is either closer or further away from the interconnector and so biases the cost outcomes for each region.

For instance the locus of Victorian generation is close to the northern end of Basslink but the locus of Tasmanian generation is well remote from the southern end of Basslink. Under the MEU approach because Basslink can and does provide the same demand in either direction, there would be no export charge in either direction, despite the fact that Transend would have to provide more assets to enable flow to Victoria than Victoria provides for flows to Tasmania.

5. MEU conclusions

The genesis of the export charge arose from the AEMC review of the impacts on the electricity market of the climate change policies. In its rule change proposal[18] the MCE advised that the main benefit of the export charge was that it would (page 5):

> "...remove a potential barrier to the co-ordinated planning of transmission investment across regions, which will become increasingly important as the dispersion of generation across the network and resulting patterns of network flows changes as a result of climate change policies."

The MCE provided no quantification for this asserted benefit but opined that the costs were expected to be insignificant and that its introduction would be simple, straight forward and require only minor amendments. On this basis the MCE considered the proposal to be a proportionate and efficient response.

The work carried out by the AEMC since this rule change proposal was submitted has shown that the implementation will not be low cost, simple or straightforward, and that it is beset by difficulties and a need to make simplifying assumptions that result in significant distortions[19]. With this in mind, **the AEMC must reassess the costs and detriments of the proposal and balance these against quantified potential benefits.**

Despite providing an alternative solution which it considers is better than that provided by the MCE and the three additional options proposed by the AEMC, the MEU considers that all of the concepts proposed to date (including its own proposed alternative detailed above) provide little or no increased overall benefit but sees that all alternatives suffer greater inaccuracies and complexities than the current approach of no export charge.

The MCE (and the AEMC in its various proposals) predicates the benefits of the export charge will derive from signals provided to participants to make change so that the market operates more efficiently. But analysis of who will change their actions because of these signals shows that the signals are likely to provide little benefit.

Transmission businesses receive their allowed revenue regardless of how the export charge is allocated and so they will not be impacted by the export charge, other than to incur increased costs from its calculation and application. Investments by existing generators are sunk and will not impact this class of

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[18] MCE Rule change request, Implementation of the rule change recommendation of the Review of the Energy Market Frameworks in light of Climate Change Policies undertaken by the AEMC, 15 February 2010

[19] The MEU detailed these in earlier submissions and summarised them in section 2 above

participant. New generators only pay shallow connection costs, so they will not be influenced by the existence of the export charge as the cost is imposed only on consumers. This means that the only class of participants impacted by the export charge is consumers.

The introduction of an export charge will significantly increase network price volatility and increase risks for existing consumers who have made significant investments on the basis there was no export charge. These investments are "sunk" and a load export charge will not impact on these users other than to change their costs. As the export charge will cause some consumers to incur greater costs, it has the potential for them to cease operations which, as the MEU points out in section 1.1, are already under significant stress from other factors. Cessation of operations will cause their contributions to transmission networks to be transferred to remaining consumers in the region, further exacerbating the increase caused by the export charge.

New consumers examine all effects on their cost structures and the load export charge on transmission might be an influencing factor, but it will be only one of many aspects that influence the final decision.

The National Electricity Objective requires that changes must improve the efficiency of the market so that there is a net long term benefit for consumers. This means that the proposed change must clearly provide a benefit. Other than an assertion that it would improve cost reflectivity, neither the MCE nor AEMC has quantified a benefit for consumers that will offset the detriments that will be incurred by the implementation of an export charge.

In its Draft Rule Determination issued on 2 December 2010, the AEMC provided some quantification of the outcomes of the proposed rule. This showed that there were likely to be significant costs transferred as a result of the proposed rule, and some large electricity users have advised that these costs, when combined with other impacts on their current costs, would be sufficient to cause them to cease operations. This reinforces the MEU view that there is potential for this proposal to result in significant detriment and the proposal needs to be seen in this light.

An export charge has the potential to increase cost reflectivity but in its application (as provided by the proposals of the MCE and AEMC) an export charge creates many detriments and complexities that detract from any benefit that the improved cost reflectivity might deliver.

Analysis of the current approach to intra-regional network pricing shows that there are so many more aspects of pricing which are not based on cost reflectivity or act to reduce it, that imposing an export charge purely because it increases cost reflectivity, is not sufficient reason to incur considerable disruption to consumers, especially where there are few, if any, benefits elsewhere for the electricity market from the change.

With these points in mind, unless the AEMC can develop a better new Rule that addresses all the concerns raised in this submission, the MEU cannot support the introduction of an inter-regional charge and recommends that the AEMC does not proceed further with this proposed new rule.

6. Response to the specific questions raised

#	AEMC Question	MEU response
1	Is the assessment criteria identified in this Discussion Paper appropriate for developing a uniform national interregional transmission charging methodology?	No. Whilst the six criteria provide a basis for assessing a uniform approach, the listing should also address whether: • there is a benefit of such a size that warrants the cost of development and administration • the assumptions and simplifications necessary to implement an approach provide adequate and appropriate signalling • equity between all consumers is achieved • the signals that result will provide sufficient impetus to generate the desired outcome in relation to causing change from the locational signals • the signals will cause unintended consequences (such as driving larger consumers out of business) • the signals aggregate the impact of the total delivered costs seen by consumers or just reflect transmission costs • those parties able to affect change see the signals (eg if generators will see the locational signals and act on them) • competitive neutrality is maintained • price signals show stability • in forcing pricing consistency across all regions, less efficient outcomes result in some regions
2	Is the criteria for assessment proposed appropriate for assessing the various options for a uniform national interregional transmission charging regime	No. See above

3	If a uniform national CRNP methodology were chosen, should the components of the methodology be specified in the NER or else left to the TNSPs to determine?	As noted above, the MEU is not convinced that a uniform CRNP methodology is the most appropriate approach to be used as the basic tool for setting transmission prices, even though the MEU does consider there needs to be increased commonality in the development of transmission pricing. The MEU considers that a common basic approach is necessary but a TNSP should be able to vary its approach for specific reasons.
4	If a uniform national CRNP methodology were chosen, which components need to be determined as part of a uniform national CRNP methodology?	See section 1.6
5	If an inter-regional transmission methodology was chose which required a consistent form of CRNP methodology, would the standard CRNP or modified methodology be the most appropriate to use for inter-regional transmission charging?	A common approach should be used. The MEU does not have a view whether one or other option is better suited to a common approach as there is insufficient information provided in the discussion paper to form a view.
6	If an inter-regional transmission methodology was chosen which required a consistent form of methodology for determining the operating conditions for cost allocation, would the 10-day system	See section 1.6. The MEU considers that only the peak hours on the peak system days should be used for allocating costs.

	peak methodology or 365-day element peak methodology be the most appropriate to use for inter-regional transmission charging? Or, is there another more preferable alternative?	
7	To the extent that there are any differences between TNSPs' measure of demand for setting and calculating prescribed locational and non-locational TUoS services, and prescribed common transmission service prices and charges, is it necessary to have a single measure of demand in order to achieve a uniform inter-regional transmission charging regime?	See section 1.6
8	To the extent that there are any differences between TNSPs' asset valuation methodologies, is it necessary to have a single methodology to achieve a uniform interregional transmission charging regime?	See section 1.6
9	If a LEC were chosen, would the modified LEC be preferable to the original LEC	On the basis that the mLEC assesses the marginal cost of providing assets to export power, it provides a better solution to the oLEC. However the mLEC still

	proposed in the draft Rule determination?	retains many features that prevents it from being acceptable as a method for calculating an export charge. These detriments are discussed more fully in section 3.1
10	If a LEC were chosen, would there any other difficulties in applying the modified LEC?	Yes. See section 3.1
11	Is the modified LEC preferable to the other inter-regional transmission charging options proposed in this Discussion Paper?	None of the options discussed in the discussion paper provide a solution that is equitable or appropriate.
12	If a Cost Sharing option was chosen as the inter-regional transmission charging approach, which methodology should be used to identify the assets which allow for interregional flows? For instance, could the assets be determined by a load flow analysis?	The MEU considers that the "spine" of the network which basically delivers inter-regional trade should comprise the assets used for cost sharing. Such delineation would be made on a qualitative basis as load flow analysis would include the flows on parallel paths which are not really part of the "spine" of the NEM transmission system.
13	Which assets should be covered in an inter-regional transmission charging arrangement? Should the cost of existing transmission assets used to allow for interregional flows be included? Should there be a technical threshold applied in	As most of the "spine" would be located in NSW and Victoria, the approach to cost allocation has to be adjusted (again probably on a qualitative basis) to ensure equitable cost sharing with the SA, Tasmania and Queensland consumers. Using load flow analysis, volume or a consumer numbers basis would lead to inequity in cost allocation. Whilst demand is the driver of asset investment, demand would not be an appropriate approach to use in the cost sharing approach.

	order for assets to be included?	With volume, customer numbers and demand not being an appropriate basis to allocate costs, this raises the concern as to what is the most appropriate basis to allocate costs
14	In allocating costs under a Cost Sharing option, what methodology should be used? For instance, should it be allocated on a simple split based on the size of a TNSP's customer base?	See response to question 13
15	Under a Cost Sharing option, how should the costs be recovered from customers? For instance, should it be recovered on a postage stamp or locational basis?	Consumers in a region are charged for locational TUoS based on demand. As noted in the response to question 13, demand is not an appropriate approach to allocation of costs under the cost sharing option. This means that the costs resulting from the cost sharing option might be better recovered in the general postage stamp approach used for non-locational TUoS as with other cost adjustments (such as IRSR, and over/under recovery) but this is not ideal either.
16	Would a Cost Sharing option be preferable to the other options proposed?	None of the options discussed in the discussion paper provide a solution that is equitable or appropriate.
17	Would it be possible to apply a CRNP methodology on a NEM-wide basis? If so, what difficulties would be faced?	Yes, assuming that the computer program (T-price) used by all TNSPs is capable of managing such a large data base. However this approach does not overcome the basic problems identified with both the mLEC and cost sharing approaches and removes any flexibility for transmission pricing between regions which might provide a benefit to consumers.
18	If so, how easy would it be for the	Implementation is a matter of cost and as TNSPs and AEMO (as the national

	transmission businesses in the NEM jointly to implement a NEM-wide CRNP methodology?	planner) recover their costs from consumers, cost would not be a problem to the TNSPs or AEMO, although it would be an issue for consumers. Getting AEMO as the national planner to apply the approach would allow a single methodology to setting the costs but increase the administration costs significantly, raising the concern that the benefits of a marginally better cost reflectivity will be outweighed by the transactional costs of achieving it.
19	Would a NEM-wide CRNP methodology be preferable to the other options proposed?	None of the options discussed in the discussion paper provide a solution that is equitable or appropriate.
20	Are there any options for a uniform national inter-regional transmission methodology (other than the three options presented in this Discussion Paper) that should be considered?	See section 6.4

APPENDIX 1 – Email exchanges between MEU and AEMC

[redacted]

Subject: Re discussion on IRTUoS

[redacted]

Thanks for the chance to provide the MEU's further views on the issue of IRTUoS. The MEU supports the principle of cost reflective pricing but we reiterate our concerns on the practicalities of implementation (based on the proposed methodology) as demonstrated by the calculations for IRTUoS which are getting quite complicated and showing perverse outcomes as we discussed in our email of 22 March (attached).

To reiterate some of the points we made in our telephone conversation

- We believe that the issue of IRTUoS needs to be examined from the viewpoint of a consumer, especially as it is consumers that will pay the LEC in their TUoS charges. This then leads to the basic question "where is the consumer benefit?" Cost reflectivity in principle is important, but the purpose of providing signals is to generate a better (more efficient) outcome. If the cost adjustments do not provide a signal to those that can make a change, then the value of the signal is questionable.
- As we see it, on the simplistic basis we provided in our email on 22 March, the proposal to charge just for locational TUoS is likely to give a better outcome compared to the previous proposal, but when the numbers were worked out, the outcome was not reflective of the intuitive result we expected. You mentioned that you would be looking to calculating the overall flows, like examining the export from Qld and seeing where it ends. In this way the LEC we calculated for Victoria might be transferred to other regions. This is possible, but it would increase the transaction costs considerably (these can be significant given the relatively small magnitude of the overall transmission costs). Other aspects to this approach would have to be accommodated, such as if there is a flow to Victoria from SA, and Victoria exports to both NSW and Tas, where do you assume where the SA generated power goes?
- This would be further complicated where there are two interconnections, such as Heywood and Murraylink between SA and Vic. As we noted in our first submission (pages 15 and 16), there is a general westward flow at Heywood and a general eastward flow at Murraylink. For some 40% of the time in 2009, flows on these two connectors were in opposite directions. This makes the actual calculations more complex and introduces the issue of the value for reliability.

- If there are counter flows on the two connectors, it implies that one (probably Murraylink) is providing improved reliability to the Mildura region of Victoria as obviously supply from within Victoria is not possible. So how to value that reliability? Currently consumers see that cost of reliability in terms of "if it is used once a year then it is paid for as if it is used all year". This approach has prevented many self generation projects from getting even to first base.
- When we looked at the outworkings from the observations in our 22 March email (where only Victoria is liable for the LEC and all other regions get a benefit even though Vic is a net exporter – resulting in a counter intuitive outcome) it became apparent that the cause was due to the specific locations of generation in NSW, SA and Tas. In each case the locus of the generation in these states is remote from the Vic border, leading to a large TUoS cost. In contrast, the locus of generation in Victoria is close to the NSW and Tas connection points meaning the cost for Vic to export is quite small. It is the locational decisions of the generators that causes this disparity, so allocating the LEC so that Vic is the only payer further mutes locational signals for generation in SA, NSW and Tas.
- One of the main drivers of the IRTUoS was to allocate a cost to importing regions. If generators (eg high efficiency wind farms on Eyre Peninsula) choose a location to maximise their benefit it will mean that there will be cost increases to SA consumers (and potentially Vic consumers if an LEC is introduced) to augment Pt Augusta to Heywood assets. The only economic assessment made by the generators as to whether high efficiency wind farms in Eyre Peninsula are a better overall solution than lower efficiency ones located in Victoria or NSW relates to potential congestion and losses. Looking at the total cost for the delivery of power to Vic, Vic consumers will pay an LEC based on significant augmentation of the transmission network if the Eyre option prevails when the cost from a Vic consumer viewpoint might be to pay a little more for less efficient generation in Vic but without any transmission upgrade. We must remember that consumers see the cost of power as the sum of generation plus transmission whereas generators only see the cost of generation.
- As we discussed, the Transmission Frameworks Review (TFR) is likely to change things considerably (if it doesn't it raises the question of why have it). We see that tinkering with the IRTUoS when there are likely to be major changes from the TFR which will impact on the IRTUoS further (and potentially have significant cost impacts) is putting the cart before the horse. We would much prefer to readdress the issue of IRTUoS after we have some direction from the TFR.
- Your view is that by looking at the total flow impacts (ie from Qld via NSW and Vic to SA/Tas and in the reverse direction) this might reduce the impact on Vic consumers. Based on the figures in our email of 22 March, SA would get \$12m, Qld \$5m, Tas \$5m and NSW zero and Vic would pay \$23m. We observe that if your approach does reduce the amount Vic pays, the amounts the others get

will be less. With the increased transaction costs (which consumers pay) there becomes only a marginal benefit of the IRTUoS to each region (if at all). To establish a new rule for such relatively small but uncertain net benefits seems not to be "in the long term interests of consumers", especially when the new rule is likely to be impacted by the TFR and potentially has to be changed in two years time.

- As was noted during our discussion there is expected to be some annual variation in the LEC compared to the single year 2008/09 that has been costed. In this regard we note that large consumers are already seeing the impact of the variation in non-locational TUoS with respect to the inter-regional settlements residue and this causes some concern already due to the resultant variability of TUoS prices. Adding a variable LEC will exacerbate this annual variability making it more difficult for large electricity users to budget for next year costs.
- Whilst the overall cost numbers are not large in relation to the total payments for transmission services, we note that depending on methodology applied, the cost impacts on individual large consumers could be quite large (as mentioned to you recently in our discussions). As well, the outcomes can be quite perverse, as illustrated by applying the latest proposed methodology. Worse, it undermines the principle of sending efficient locational signals to generators. The latest set of figures, which require close scrutiny, adds considerably to transactions costs, indicating that we are fast approaching the point of diminishing returns with the proposed LEC.

We would be pleased to provide more input, or to review other proposals, if this will assist you in developing a better outcome. As the changes you have discussed with us are a considerable variation from the draft rule that was reviewed by stakeholders, if you decide to proceed with an IRTUoS rule, we suggest that the changed approach should be issued as a draft rule for wider consultation before issuing a final determination.

Regards

[redacted]

Major Energy Users, Inc

[redacted]

Subject: RE: MEU response to IRTUoS rule change

[redacted]

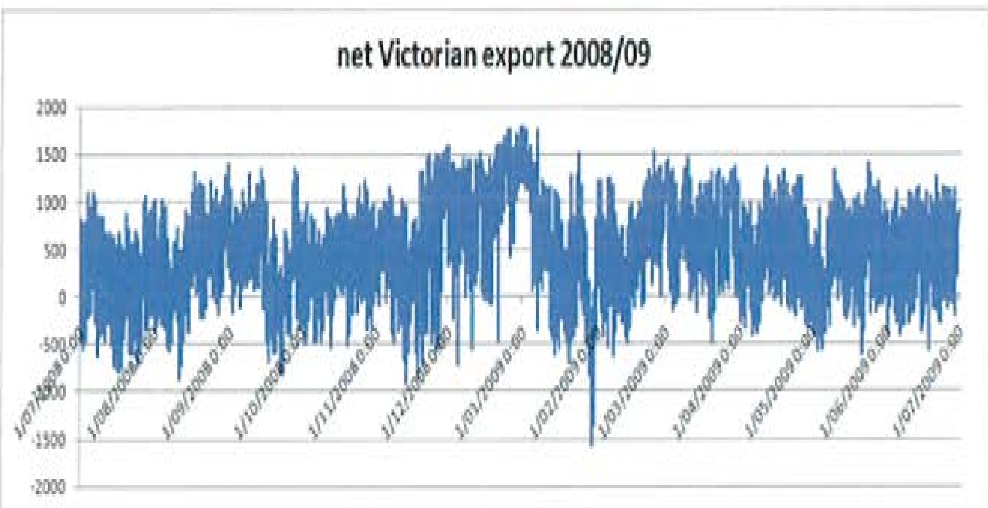
Thanks for the heads up

We are free at 2pm Thursday for the teleconference.

...

From the overview that you have provided, we see that many of the problems we saw are either minimised or addressed but our remaining concerns are:

- There still needs to be a recognition of the value of the improved reliability of supply that it provided even if the interconnection is only used occasionally – this particularly applies in the case of Basslink where all of the costs of the interconnector are carried by Tasmania
- We still see that the locational TUoS should be set when the system is most heavily used so that peak users carry their fair share of the cost of the networks. In this regard we support the AEMO approach used in Victoria over the annual averaging approach used in the other regions. We see this is more cost reflective for allocating the cost of the assets used.
- Allocating only locational TUoS as the LEC, using the table 7.1, we see that all regions now become beneficiaries of the new rule ($12.5m going to SA, $5.4m to Qld, $5m to Tas and $0.3m to NSW) except for Victoria which has to pay some $23m, yet Victoria was a net exporter of power for the year with an average export of some 420 MW each half hour. To charge Victorian consumers an average premium of some $0.50/MWh as a load import charge despite being a net exporter, seems incongruous so perhaps the approach needs be adjusted to reflect reasonableness



Regards

[redacted]

Major Energy Users, Inc

[redacted]

Subject: RE: MEU response to IRTUoS rule change

[redacted]

Thank you again for MEU submission to the draft Rule and the opportunity to talk through the issues.

The Commission has now had a chance to review the submissions to the IR-TUOS draft Rule Determination. It has decided to proceed to make the final Rule but with some changes to policy.

The crucial difference being considered is the load export charge will only comprise the locational TUOS charge and not the postage stamp components to TUOS charges. The Commission is also considering moving the start date to 1/7/13 to gave the TNSPs more time to develop their pricing systems.

We would like the opportunity to discuss the policy with MEU and the progress going forward. Would you be free this Thursday or Friday for a conference call to discuss this?

Kind Regards

[redacted]

AEMC

[redacted]