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25 February 2011

Mr John Pierce
Chairman
Australian Energy Market Commission
PO Box A2449
SYDNEY SOUTH NSW 1235

SUBMITTED ONLINE

Dear John,

Submission in response – Draft Rule Determination Inter-regional Transmission Charging Rule Change - ERC0106

We welcome the opportunity to respond to the AEMC's Inter-regional Transmission Charging Rule Change. Transmission charging is an important and complicated matter and changing the way it is calculated can have real, financial consequences for regions and individual market participants. However, if the changes meet the efficiency objectives in the National Electricity Objective (NEO), then we should be certain of obtaining the best result for the market as a whole.

AEMO supports inter-regional TUOS charging provided that it is done in an efficient manner and in the least distortionary way possible. We also agree that in order to have a workable charging system, the underlying pricing methodologies need to be aligned and consistent between regions. However, conclusions from our own modelling suggest that the pricing methodology proposed may not be the most efficient method. Ultimately, we would like to see a single disinterested entity determining transmission prices based on provision of services rather than with the recovery of asset costs. In the attached submission we explain the outcomes of our modelling exercise that have allowed us to reach these conclusions.

We look forward to working with the AEMC in developing the Rule change proposal. If you have any questions regarding this submission, please do not hesitate to contact me on (08) 8201 7371.

Yours sincerely

David Swift
Executive General Manager Corporate Development

Attachments: Submission to AEMC's Draft Determination on Inter-regional TUOS Charging

SUBMISSION TO AEMC'S DRAFT DETERMINATION ON INTER-REGIONAL TUOS CHARGING

25 February 2011

Contents

1 Executive Summary

AEMO appreciates the opportunity to respond to the rule change proposing the introduction of inter-regional transmission use of system charges (IR TUOS). We believe that transmission pricing is an important and complex aspect of the NEM. Charging transmission on an inter-regional basis is a big step in the evolution towards a fully integrated NEM. Any change in the way that it is carried out could have unexpected or unforeseen consequences.

AEMO carried our further TPRICE modelling from that which was originally requested by the AEMC. This enabled us to more fully explore the likely impacts of the proposed changes to the TUOS regime. The analysis was designed not only to isolate the effects of inter-regional charging from the present structure but to determine what effects moving to a consistent pricing methodology might have. Currently, the National Electricity Rules (NER) state that pricing must be based on demand at times that system demand is at its highest loading and is generally the time that network augmentations are more likely to be contemplated.[1] The AER's Pricing Methodology guideline allows Coordinating Network Service Providers (CNSP) to choose between two methodologies.[2]

The AEMC (or the AER in its guideline developing role) must choose which pricing methodology must be applied by CNSPs in order to achieve the necessary consistency required of an inter-regional TUOS regime. This means that an assessment must be made of whether the methodology adopted better achieves the National Electricity Object (NEO)[3] than the alternative.

With this objective in mind, AEMO's view, informed by the objectives of transmission pricing (which are set out in Appendix 1) and the outcome of its analysis, are:

- AEMO agrees with and supports a NEM-wide TUOS pricing regime where charges are levied inter-regionally, provided that it is under-pinned by a pricing methodology that best satisfies the efficiency objectives of the NEO. This includes linking transmission pricing with provision of services rather than with the recovery of asset costs.
- AEMO agrees with and supports a single and consistently applied model and pricing methodology to achieve an efficient pricing regime. As part of this, AEMO believes that this would be best achieved by having an independent body (such as the AER) set transmission prices on a national basis, based on information provided by CNSPs. If a single entity model cannot be implemented, then some of the issues identified in this submission, such as the iterative process required to locationally charge locational import charges to further regions must be resolved in a workable manner and to best satisfy the NEO. One approach would be to set out the method in detail in an annex to Chapter 6A of the NER.
- AEMO considers that a pricing methodology based on usage at times of system peak loading, rather than one based on peak individual element loading, best meets the NEO. The latter method will be less likely to efficiently allocate transmission costs associated with the introduction of generation encouraged by climate change policies as suggested by the AEMC's Review of Energy Market Frameworks in light of Climate Change Policies (Climate Change Review).[4]

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[1] Rule 6A.23.4(e), National Electricity Rules states "Prices for recovering the locational component of providing *prescribed TUOS services* must be based on demand at times of greatest utilisation of the *transmission network* and for which *network* investment is most likely to be contemplated."

[2] The AER will need to update its Pricing methodology guidelines published in October 2007.

[3] Section 7 of the National Electricity Law states "The objective of this Law is to promote efficient investment in, an efficient operation and use of, electricity services for the long term interests of consumers of electricity with respect to-

(a) price, quality, safety, reliability and security of supply of electricity; and

(b) the reliability, safety, and security of the national electricity system.

[4] Review of Energy Market Frameworks in light of Climate Change Policies Final Report, AEMC, September 2009, p. iv. http://www.aemc.gov.au/Market-Reviews/Completed/Review-of-Energy-Market-Frameworks-in-light-of-Climate-Change-Policies.html

- AEMO believes that, on balance, non-locational costs (including common service costs) should be "postage-stamped" and allocated inter-regionally on the same basis as they allocated intra-regionally. In this way their allocation is least distortionary.

2 Objectives of IR TUOS

Having a regionally separated electricity market, the NEM has for many years grappled with the issues associated with inter-regional transmission charging. The AEMC's Climate Change Review recommended that inter-regional TUOS be introduced primarily because government policies designed to encourage renewable and lower emissions generation sources were likely to restrict investments to particular regions. It was therefore considered appropriate to allow those regions to pass the costs of transmission investments needed to accommodate the uneven distribution of such generation throughout the NEM.

In addition to this, it may also have the added benefit of persuading TNSPs to promote transmission investments that have cross-region benefits. It is sometimes suggested that TNSPs might be reluctant to invest in a transmission augmentation where the benefits substantially flow to adjoining regions.

3 Explanation of pricing methodologies and TPRICE

There are two different methods used by CNSPs to calculate the locational component of transmission charges in the NEM. The first method (referred to as the system peak method) is used in Victoria by AEMO in its Victorian transmission service provider role. The second method (referred to as the element peak method) is used by all other CNSPs in the NEM.

Both methods of calculation are available within TPRICE, the network modelling tool used exclusively by the CNSPs in the NEM to calculate TUOS locational prices.[5]

3.1 System peak method

The system peak method measures each load point's network element usage (in MW) coincident with peak system loading in a given time period (for example, monthly, 6-monthly, yearly). In its purest form, this will seek to measure each network element's loading at the unique time that coincides with system peak over the sample time period.[6]

In Victoria, AEMO has applied a variation on the system peak methodology for transmission pricing. Instead of taking a single top peak day or trading interval, it identifies the top ten trading intervals over a year. Measurements of each load point's loading of system elements are taken at times coincident with the identified system peak periods. Those measurements are then averaged to obtain a single figure. This allows each load point's proportionate demand relative to the average loading of the whole system over those ten peak intervals to be determined. The revenue requirement for the pricing period (the locational component of AEMO's *ASRR*) is apportioned (by the TPRICE model) to each load point according to its contribution to system peak demand.

3.2 Element peak method

By contrast, the element peak methodology measures the peak loading of elements (in MW) supplying a load point over a period independently of system peak. Under this method, a reading of the peak loading of each element relating to a supply point is obtained over the entire year (365 days). All the readings are then summed to obtain a notional system demand and revenue is apportioned (by the TPRICE model) on the basis of each load points contribution to that overall demand.

[5] AEMO also uses TPRICE to calculate forward looking marginal loss factors on an annual basis.

[6] If an exact system peak registers on more than one occasion over the sample period, measurements are averaged to obtain a single measure of each element's loading.

3.3 AEMO's TPRICE analysis and modelling methodology

In addition to the modelling exercise conducted in preparation for the AEMC's draft determination, AEMO also conducted a further modelling exercise to isolate the locational price effects of moving to an element peak methodology on the Victorian region as well as estimating the likely inter-regional effects. The modelling used TPRICE, configured in a manner consistent with the requirements of the Cost Reflective Network Pricing (CRNP) rules in Chapter 6A the NER.

To assess the relative use of the system, TPRICE carries out load flow studies for a number of system operating conditions and for each condition a full load flow is set up from historic system load and generation conditions. This enables an allocation of generation to load such that a particular load is distributed among generators. The result of this process is an allocation of power to the "electrically closest" generators to the load.

The annualised revenue requirement based on optimised replacement costs (ORC) of the elements that distributes the power as described in the previous paragraph is then allocated to the load and a price is derived for that load point. The data used for the modelling exercise was from the 2008/09 financial year.

The output of the modelling exercise was a table of locational prices at load points (inclusive of all of the interconnectors in the Victorian region under both a system peak methodology and a element peak methodology.

4 AEMO's interpretation of the modelling results

AEMO approached the interpretation of the results in the context of economic efficiency objectives and from the objective of attempting to achieve consistency between regions.

The first of the two above perspectives is considered in light of the economic objectives set out in Appendix 1. The second is a practical consideration driven by the requirement that if regions are to be charged for the use of a neighbouring region's transmission system, calculation of the import charges must be done on a reliably consistent manner.

4.1 Consistency

One of the principles that the AEMC wanted applied with the introduction of an inter-regional TUOS pricing regime is that it should cause as little disruption to the CNSP's price determination processes as possible. However, it became clear that the two methodologies outlined above would yield different results at regions' borders and therefore justifying alignment of approach for all regions.

There are many variables in the application of TPRICE other than the pricing methodologies that would result in potentially substantial divergences. The TPRICE model is complex and has many flexible parameters. There are also parameters outside the application of TPRICE that should be considered. Consistency of approach can be difficult and therefore needs more transparency than is currently the case. The AEMC should consider how these matters are to be dealt with and also ascertain whether there are any more issues that need to be considered. Some of the issues that AEMO considers significant are:

- Consistent database of unit transmission elements' ORC. The foundation blocks of the valuation process needs to be explored in order to be sure that each TNSP uses the same fundamental valuation base. We agree that each region may have different topography that affect base transmission costs. However, our understanding is that in an effort to standardise valuation in the past, two base methodologies were allowed – rural/non-rural, and flat/hilly terrain. Further, the current approach of requiring AER approval of individual TNSP pricing approaches is still likely to result in some inconsistent applications over time.
- Consistent application in TPRICE of the "fault contribution matrix" method of allocating generation to load as required by the NER both intra-regionally and inter-regionally. Furthermore, we raise the question whether the "modified CRNP methodology" in

rule S6A.3.3 NER might create sufficient pricing differences compared to regions that use the "CRNP methodology" in rule S6A.3.2 NER.

- Consistent use of "zeroreverse" to discount usage of transmission by loads that would logically reduce total loading on an element.
- Use of "alphascale" to deal with marginal loss factors should be applied in a consistent manner.

4.2 Economic considerations

As stated previously, adopting a consistent methodology is essential to having a sensible inter-regional TUOS charging regime. However, the results of AEMO's modelling exercise suggest that moving towards an element peak methodology from a system peak methodology could have the following consequences for the Victorian region:

- Customers who can vary their load (direct connect customers) have less incentive to avoid using the transmission system during system peaks under the element peak method.
- The element peak method tends to dilute the locational signal to locate closer to generation.
- The element peak method allocates significantly more to interconnectors and result in less efficient system usage.
- It is not clear how the objectives of avoided TUOS can be effected by the element peak method.

4.2.1 Locational charges

As a general proposition, provided they are calculated under the CRNP principles set out in the NER, locational charges represent an efficient cost allocation and therefore are justified in being passed on to other regions. However, some results from AEMO's modelling exercise indicate some adverse economic effects in transitioning to the element peak methodology for Victoria.

AEMO's analysis found that in general, both methods allocated proportionately more revenue relative to its load the further from generation the load was located. Therefore, both apportioned relatively more revenue to load points such as Red Cliffs, Horsham and Kerang compared to loads very close to generation such as Morwell. This is what a well designed transmission pricing regime is meant to do.

Both methods also apportioned more revenue to loads that demand more from the network. Therefore, loads closer to Melbourne, such as Thomastown, Richmond, Brooklyn all bear a greater proportion of the revenue requirement than say Kerang which draws a relatively very small load (despite its distance from generation).

However, despite this commonality, there are differences in revenue distribution between the two methods that deserve some further discussion. A graph of some of the load points within the Victorian region (including all of the interconnectors) appears in Appendix 2[7] showing the change in locational charges to selected load points in moving towards a element peak methodology. Overall, the element peak method apportioned less of the revenue requirement to each internal load point (that is, a point that is not an interconnector) than the system peak method did. This was because the element peak method apportioned a greater proportion of the revenue requirement to the interconnectors.

This is consistent with the purpose behind the element peak method as it seeks to measure the absolute peak of each element over the year which will usually be higher than the system peak method.[8] Consequently, when an additional load point is added to the system (such as the interconnectors), the new load points make up a much greater proportion of total system capacity

[7] Note: not all Victorian load points appear on the graph, so summing all the percentage contributions will not add to 100%.

[8] The system peak method's peak measure can never be higher than the element peak method's measure for a given element.

than the system peak method. The system peak method will produce the same result only if the element peak coincides with a system peak day.

This has the potential to lead to the following:

- *Less incentive to avoid use of transmission during system peaks*

Some direct connect customers have relatively flexible loads and are able to vary their own load at times of system peak and thereby provide some relief. If this incentive is strong, it provides sizeable benefits by potentially deferring immediately necessary transmission augmentations.

Pt Henry and Portland Smelter are cases in point. Both Pt Henry and Portland Smelter are aluminium smelters that draw significant load from the transmission system and both have the capability to reduce their TUOS charges by voluntarily reducing their loads at times of peak system loading. However, the analysis suggests that for these loads, the element peak method tends to diminish the incentive to do so.

The reason why that incentive is reduced is that the element peak method uses the element peak loading to price the load point no matter when that peak occurred. So if the peak occurs at 11.30 am on a mild spring day, a time of the day and year when there is little loading on the system as a whole, that load point is still charged a maximum TUOS price. This is notwithstanding that it had the capability to reduce its load at system peak and therefore potentially contribute to the deferral of a necessary augmentation.

AEMO's view is that a load that places stress on the system at times of peak demand is much more likely to contribute to a need to augment than one that occurs at times of lighter system loads. A pricing methodology that reflects this better placed to meet the NEO.

- *Less incentive to locate closer to generation sources*

The outcomes depicted in Appendix 2 suggest that notwithstanding that both methods charge proportionately more to loads located further from generation, the system peak method provides a stronger signal. The Pt Henry load has the Anglesea generator embedded behind its system connection point and although the smelter draws substantially from the transmission system, it also takes a significant amount from the power station when it is generating.

The generator participates in central dispatch according to its bidding strategy and therefore it is hard for the smelter to align its load requirements with the generator's operating schedule on a daily basis. But it does attempt to coordinate its own outage schedule with that of Anglesea power stations where it can, in an effort to reduce its TUOS charges.

Another example is provided by Morwell (a generation rich area) where the charge under the system peak method is lower than under the element peak method. In general the system peak method charged loads less the closer they were to generation and more the further away they were in comparison to the element peak method.

- *Element peak method lessens the effectiveness of avoided TUOS*

Where a generator is located in the distribution system and can show that by its operation it can avoid the local retailer TUOS charges that would otherwise be payable by it were it not for the embedded generator, the NER allows the embedded generator to be paid those avoided TUOS amounts.

AEMO is unsure how the element peak method can integrate the avoided TUOS system. Under that methodology, the embedded generator would need to operate every day of the year to ensure that it can qualify for the payment. In practice this is unlikely to happen because all generators must be taken offline for a time each year for maintenance.

In comparison, under the system peak method, the generator would need to operate at the times of year where the system is likely to be at its peak loading. Victoria does have an embedded generator located in the south-east of the State that qualifies annually for an avoided TUOS payment. We are unaware of any examples in other regions.

- *Element peak method allocates significantly more to interconnectors.*

The analysis of AEMO's modelling exercise shows that the element peak method allocates and charges significantly more to the interconnectors than the system peak method. The reason for this is that the former method uses an interconnector's absolute peak loading during all trading intervals in the year. By contrast, the system peak method, is restricted to using only the peak identified during the 10 highest system load intervals.

By way of example Appendix 2 shows that under the element peak method, the NSW region is charged considerably more for Victorian exports than under the system peak method. This is because NSW is far less likely to import from Victoria at times of high Victorian system loading than at other times. This suggests that NSW imports considerably more energy at times when Victorian energy prices are relatively lower than in NSW which corresponds to lower system loading in Victoria.

AEMO questions whether this represents an efficient pricing mechanism. From an efficiency perspective, if the NSW region and Victorian generators benefit from the export to NSW of relatively cheaper energy at times when it does not impinge on system capability, it is questionable why NSW should be charged so much. In theory, these charges have the capacity to create perverse incentives to avoid using an under-utilised system if the charges are sufficiently high. In practice, it is hard for an entire region to avoid such charges given the NEM's dispatch process.

Another example of an unusual outcome capable under the element peak method is shown by the Vic/SA interconnector. Under the modelling exercise conducted by the CNSPs for the AEMC, the SA region calculated an export charge to the Victoria region of $27 million. We assume that such a sizeable amount of SA exports into Victoria was caused by wind generation and, if consistent with historical wind generation patterns, that it was generated at a time that was not coincident with high system loading in SA. Similar to the argument above in relation to Victorian exports to NSW, we find it hard to justify an import charge on the basis of efficiency, if the SA system is under-utilised and not in need of investment to clear such generation.[9]

There is a point at which an importing region would prefer to physically locate the marginal generator in the importing region rather than augment the exporting region's transmission system. We believe that because it measures element usage at the time of heaviest system load (and therefore coincidence of high energy price and high network value reflecting scarcity) the system peak method would provide a much better pricing indication of the timing of augmentation required to relieve congestion. This point is expanded further below.

Lastly, we note that there is a view held by some TNSPs that other provisions of the NER[10] restrict distribution of import charges on a locational basis to intra-regional load points only and not carry them through inter-regionally via other interconnectors. For regions such as Victoria and NSW, that will mean that any import charges will remain in the region even when interconnector flows justify that they be passed onto an adjoining region.

4.2.2 Practical limitations

The previous discussion highlights the practical limitation of having individual CNSPs calculate transmission pricing for their region including import charges. The alternative is to have a disinterested body solve locational pricing for the whole NEM.

It removes the need to run further TPRICE runs once an exporting region notifies the importing region of its import charge. In fact, it should remove the need to have import and export charges entirely. The costs of transmission at a load point anywhere in the NEM would be inclusive of the costs of any element needed to serve that load point irrespective of where that element is located.

[9] The estimated import charge from SA to Victoria seems to be intensified by the fact that the SA portion of the Vic/SA interconnector is particularly long and carries little SA load on it after it leaves the more populated part of the State. Consequently, a very high proportion of its annual costs would be allocated to the Victorian region.

[10] We understand the reasoning to be that because some TNSPs' TUOS price publication deadlines do not align with others', that all CNSPs are limited to doing just one further TPRICE run subsequent to receiving notification of import charges.

There is no need to treat interconnectors as notional load points on the importing region in this case. The AEMC might wish to further consider this alternative.

4.3 Justification for IR TUOS and meeting the NEO

4.3.1 Investments as a result of climate change policies

We mentioned earlier that one of the justifications for introducing inter-regional TUOS is to allow regions to pass through transmission investment costs where government environmental policies (such as ERET and carbon pricing) causes a disproportionate distribution of some types of generators to locate in a particular region or regions (for example, to date, the bulk of wind generation has located in South Australia with incentives from the ERET scheme).

However, we should consider that there is a point at which it is more economically efficient to locate the marginal generator in a less optimal position than to build transmission to relieve congestion in the generator's most optimal region.[11] IR TUOS, as currently intended, will not help solve for that or send a signal to generators to locate elsewhere.

Particularly for wind, building transmission to export energy at times when it is not that much cheaper than average pool price (i.e. winter, evenings etc) is probably not the most efficient outcome and therefore it could be seen as sub-optimal to pass these costs on to the importing region. We are not sure that this level of analysis is undertaken in RIT-T assessments and consequently, there is a risk that inefficient costs might be passed on to adjoining regions.

AEMO is willing to assist the AEMC consider the best approach to meet the NEO standard if it felt it warranted. AEMO considers that one approach is to ensure that full market benefit analysis (including costs of unserved energy[12] inclusive of benefits to importing regions) is done to justify transmission investment for generators. This should ensure that not only the network investments themselves are efficient but that the resulting charges would be more efficient.

4.3.2 Meeting the NEO

We understand that the move to one consistent locational pricing methodology is to be effected by the AER in its guidelines. A consistent methodology is necessary for the calculation of nationally consistent inter-regional TUOS charges. However, AEMO contends that this should not occur at the expense of a loss of economic efficiency. We therefore believe that the AER in developing the guidelines must also be mindful of the NEO objective and the AEMC should make it clear in its final determination that the NEO is the correct measuring tool. It is arguable that the element peak method might, due to the larger sample size (that is 365 days rather than 10 days) produce more stable pricing over time. It is also arguable that it is more equitable because customers that can control their loads do not have the opportunity to reduce their demand on high system load days and therefore potentially reduce their TUOS charges at the cost of other network users. However, neither of these outcomes results in a more efficient use of the transmission network and therefore, in AEMO's view, the system peak method better satisfies the NEO .

In summary, we conclude from our analysis that:

- The element peak method has the potential to lessen locational signals compared to the system peak method for direct connect customers that can control their loads.
- The element peak method has the potential to lessen the incentive to reduce consumption at times of high system loading on customers that are able to do so. It also dampens any incentive for embedded generators to locate where avoided TUOS may be maximised and therefore reduce reliance on the transmission system.

[11] For clarity, we are not referring to connection costs which should be borne by the generator proponent. The discussion here concentrates on shared network augmentations undertaken by the TNSP to remove congestion caused by the marginal generator.

[12] The RIT-T mandates cost benefit and NPV type analysis but does not require that involuntary unserved energy be valued when a Jurisdictional reliability provides a mandate for a TNSP to build transmission.

- The element peak method has the potential to pass on less efficient transmission costs to importing regions because it measures peak export at any time of the year and therefore encourages less efficient use of the system. Therefore we believe that it is not as adept at meeting the objective of the Climate Change Review as efficiently as the system peak method.
- Unless there is a single TPRICE run that considers the NEM regions together, locational charging of import charges would need to be done in an iterative process until resolution is reached. Accordingly, a single NEM-wide TPRICE run without artificial load/generator points at each region border may be justified.

4.3.3 Non-locational charges

Non-locational and common services are not efficient charges and therefore there is debate about whether they should be charged inter-regionally. Non-locational charges are the net amount to be recovered by a TNSP after the locational component is carved out of the revenue requirement. It includes a range of sundry costs including recovery of ‘bypass’ costs, over and under recovery of past costs and costs that could not be said to benefit any particular existing customers (for example scale components of an investment).

Where individual beneficiaries are not clear, the costs should be distributed in a manner that minimises distortions. In the current TUOS regime, non-locational and common service costs are “postage stamped” in a manner that is least distortionary to customers. Consequently, customers have a choice as to whether they are charged on a MW or MWh basis depending on what best suits their consumption profile. Provided that this is still able to be done for any non-locational portion of an import charge, then it seems that the distortionary aspects of allocation of such charges could be avoided and therefore pass-through may be justified.

It is also arguable these are still transmission related costs (including the Victorian easement land tax) and therefore it may be entirely appropriate to pass these costs through on the same justification as they are charged to customers in the current intra-regional regional system. Furthermore, not being able to pass through non-locational costs would limit inter-regional recovery of costs to less than half of all annual *ASRR* for *prescribed TUOS services* costs. This may be seen to weaken the intent of inter-regional TUOS.

On balance, AEMO believes that it is better to pass through non-locational costs on the same basis as they are currently charged to customers intra-regionally, provided that they are passed-through in the least distortionary way. We believe that this would better meet the NEO.

5 Conclusions

AEMO believes that implementing a single national TUOS pricing system is the most efficient pricing system that could be adopted. If the AEMC believes that this model cannot be implemented, AEMO believes that its proposed model can achieve the requirements of the NEO if a single pricing model is used and a single pricing methodology is consistently applied, based on times of peak system loading. In addition, the recovery of non-locational costs (including common service costs) should be done in the least distortionary manner possible, which in our view justifies a recovering it inter-regionally.

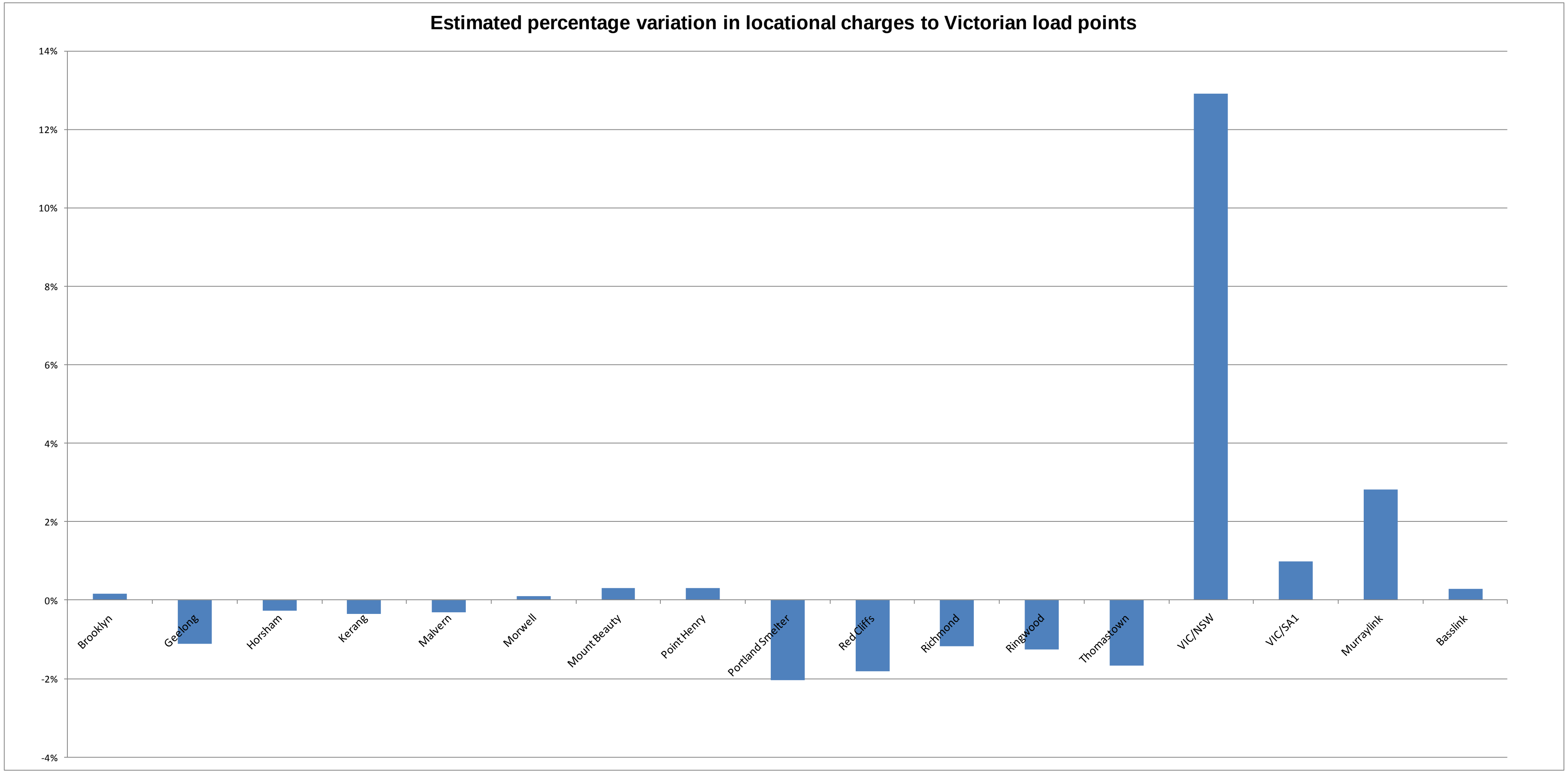
Appendix 1 - Objectives of Transmission Pricing

Transmission pricing has three main objectives:

- Cost Recovery - from a TNSP's perspective, the prices are the means to recover the costs of expanding and operating the transmission network.
- Reflect Transmission Augmentation Requirements - in terms of transmission investment, transmission augmentations are driven by capacity requirements and not system utilisation.
- Locational Signalling - ultimately, transmission investment should be demonstrably efficient. It is therefore appropriate and justifiable to charge on a locational basis. On the demand side, pricing can affect locational decisions, particularly of large, direct connect customers and influence whether users attempt to by-pass the network if the prices are set excessively high. They can affect consumption decisions such as when they choose to consume.

Although, not a transmission pricing objective, on efficiency grounds, it has been good policy to encourage avoided TUOS. Transmission pricing can, if a well designed avoided TUOS regime allows for it, affect the investment decisions of embedded generators. These are well established objectives that have previously been endorsed by the AEMC and AER.

Appendix 2 - Outcomes of AEMO's TPRICE modelling exercise



This graph shows the estimated change in locational charges to various load points in moving towards a element peak methodology