Australian Energy Market Commission

RULE CHANGE

RULE DETERMINATION

National Electricity Amendment (Inter-regional transmission charging) Rule 2013

Commissioners

Pierce
Henderson
Spalding

28 February 2013

JOHN PIERCE
Chairman
For and on behalf of the Australian Energy Market Commission

Summary

In this final determination the Australian Energy Market Commission (AEMC or Commission) has decided to make a more preferable rule in relation to the inter-regional transmission charging rule change request originally put forward by the Ministerial Council on Energy (MCE)[1]. This final decision seeks to introduce a modified load export charge.

The introduction of a modified load export charge will require that transmission businesses in each region levy a charge on transmission businesses in neighbouring regions. Consumers would subsequently pay a share of the costs of transmission in a neighbouring region used to import electricity into their region. The modified load export charge applying to each transmission business will be determined on a net basis, reflecting that all regions both import and export electricity.

The Commission considers the new transmission charging arrangements will better reflect the benefits transmission provides in supporting energy flows between regions.

Modelling performed for this determination shows a modified load export charge will form only a relatively small proportion of overall revenues earned by transmission businesses. For the period modelled (2009-2012) the net charge paid or received by a region ranged from approximately 1 per cent to 6 per cent of allowable revenues (on average over the three years).

Nationally, transmission charges equate to about 8 per cent of the prices paid by a typical residential consumer. The Commission anticipates that the average residential consumer's bill is likely to increase or decrease by less than 1 per cent as a result of the introduction of the modified load export charge.

A modified load export charge will contribute to the National Electricity Objective by promoting efficient investment in, and use of, electricity services, in a number of important ways:

- Transmission businesses will have stronger incentives to pursue transmission efficient investments for which the costs fall predominantly in their own regions but the benefits fall in neighbouring regions. This is because they can recover some of the costs of the investment from the neighbouring region.
- Prices consumers face for transmission services will be more reflective of the actual costs incurred in providing those services.
- Credibility of, and confidence in, regulatory arrangements is improved as the costs of transmission capacity used for conveying electricity between regions is allocated to the regions that derive benefits from such capacity.

On 15 February 2010, the MCE submitted a rule change request to the AEMC seeking to implement an inter-regional transmission charging mechanism in the form of a load export charge. Currently under the rules consumers in one region who benefit from the

1 In 2011 the Standing Council on Energy and Resources (SCER) formally assumed Ministerial Council on Energy (MCE) functions as the national policy and governance body for the Australian energy market.

use of transmission assets in a neighbouring region do not directly contribute towards the cost of those assets.

Modelling undertaken by transmission businesses showed that the calculation of the load export charge could vary across the National Electricity Market, partly as a result of different methodologies used to calculate such a charge in different regions. In response to stakeholder feedback on the draft rule determination, the Commission undertook further analysis and consultation on a number of different inter-regional charging options. In addition to the load export charge put forward in the rule change request, these included:

- modified load export charge;
- NEM-wide cost reflective network pricing; and
- A proposal for cost sharing by a group of generators.[2]

These options, including the original load export charge, are outlined in detail in Chapter 4.

Following further analysis and modelling, and taking into account submissions received, the Commission has made a preferable rule which it considers better contributes to the National Electricity Objective as it:

- provides more efficient price signals;
- is calculated and applied in a more consistent way;
- provides for greater transparency and regulatory stability; and
- is more proportionate with respect to consumer impacts.

In reaching its final decision the Commission has sought to balance a number of considerations, including cost reflectivity, transparency, regulatory stability and the costs of implementation.

The final rule attached and published with this determination includes a commencement date for the inter-regional transmission charging arrangements of 1 July 2015. This would require transmission businesses to first publish a modified load export charge by 15 March 2015. The Australian Energy Regulator is required to amend its pricing methodology guideline by 30 September 2014, with transmission network service providers to amend their price methodologies no later than the 27 February 2015.

The introduction of a modified load export charge will not affect the total revenues earned by transmission businesses; it will only affect how those revenues are allocated between consumers across the National Electricity Market.[3]

While some consumers will face an increase (others a decrease) in their transmission charges under the new arrangements, any such variations are likely to be small and proportionate to the issues the Commission has sought to address under this rule change request.

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2 These generators are AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo

3 A transmission business may recover less from their own consumers under the new arrangements, but more from consumers in a neighbouring region

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1 Ministerial Council on Energy's rule change request

1.1 The rule change request

On 15 February 2010, the Ministerial Council on Energy (MCE) (rule proponent)[4], submitted a rule change request to the Australian Energy Market Commission (AEMC or Commission).

In this rule change request the MCE proposed new inter-regional transmission charging arrangements so that transmission businesses in each region would levy a new charge - a load export charge - on transmission businesses in neighbouring regions. Consumers would subsequently pay a share of the costs of transmission used to import electricity into their region from neighbouring regions. Given that all regions both import and export electricity, the inter-regional charge applying to each transmission business would be determined on a net basis.

1.2 Rationale for the rule change request

Currently under Chapter 6A of the National Electricity Rules (rules), a transmission network service provider (transmission business) recovers the costs of building and operating its transmission system from consumers within its region.[5] The pricing provisions under the rules, which set out how these costs are to be recovered, are based on a set of principles and require each transmission business to develop and publish prices for each category of regulated (prescribed) transmission services.[6]

Each transmission business must also publish a pricing methodology which, in part, sets out how the revenue to be recovered has been allocated to each category of prescribed transmission service.[7] There are four categories of prescribed transmission services:

- entry services;
- exit services;
- transmission common services; and
- Transmission use of system TUOS services.

Prescribed common transmission services provide equivalent benefits to all transmission consumers on the network without any differentiation based on their location. Examples of assets that are used to provide these services include a

4 In 2011 the Standing Council on Energy and Resources (SCER) formally assumed Ministerial Council on Energy (MCE) functions as the national policy and governance body for the Australian energy market.

5 Clause 3.6.5(a)(5) of the rules provides for jurisdictions to establish inter-regional charges through inter-governmental agreement. However, in practice, inter-regional transmission service payments have been negotiated only between South Australia and Victoria.

6 The categories of prescribed transmission services are set out in clause 6A.23.4 of the rules. The allocation principles generally are set out under clause 6A.23 of the rules.

7 The pricing methodology is set out in clause 6A.24 of the rules.

transmission network service provider's control buildings, protection systems, and communication systems.

Prescribed transmission use of system (TUOS) services' constitutes the majority of the prescribed transmission services costs and is divided (approximate 50/50 split) into non-locational and locational services. Non-location TUOS services are recovered on a postage stamp basis (a charge that does not vary by utilisation or location) while locational TUOS services are recovered from consumers depending on their location. For example, the level of transmission infrastructure required will vary depending on where consumers are situated relative to generation capacity. For the purposes of developing an inter-regional transmission charge, prescribed entry and prescribed exit services are not considered. More detail on the process for cost allocation and price setting for prescribed transmission services is included in Appendix B.

The National Electricity Market consists of five interconnected regions where electricity may be exported and imported between regions. When electricity flows between regions, the provision of electricity to consumers in the importing region will utilise the network in the exporting region. Under the existing rules, however, the transmission system charges in the importing region are based on the capital and operational costs associated with infrastructure located within the importing region only. The transmission charges consumers pay currently do not reflect the costs of utilising the assets of the exporting region's network to import electricity.

The rule change request would have the effect of each region contributing to the costs of TUOS services associated with transmission assets located in neighbouring regions that facilitate imports of electricity into their own regions. The Ministerial Council on Energy considered the recovery of these costs through the transmission charges levied on consumers within importing regions would make these charges more cost reflective.

Further, transmission businesses, which are responsible for undertaking the regulatory investment test for transmission (RIT-T), may be less inclined in the absence of an inter-regional transmission charge to put forward efficient investment proposals where a significant proportion of the benefits of such investments are considered to fall outside their own region. An inter-regional transmission charge will also therefore support dynamic efficiency objectives.

1.3 Solution proposed in the rule change request

The MCE rule change request comprised the following key elements:[8]

- Transmission businesses in each region would be required to levy a new charge - a load export charge - on transmission businesses in neighbouring regions.
- The charge would reflect electricity flows between regions.
- A load export charge would reflect the costs of network assets in one region used to import electricity into another region.
- Where there is more than one transmission business in a region, one transmission businesses would be appointed the "co-ordinating network service provider." It

8 MCE 2010, rule change request - Inter-regional Transmission Charging, February 2010, pp. 2-3.

would be responsible for calculating both the charges to be levied on the coordinating network service providers in neighbouring regions and the allocation of charges payable by transmission businesses in its own region.[9]

- Coordinating network service providers would calculate the prices to be applied in the upcoming financial year in accordance with a pricing method that has been approved by the Australian Energy Regulator (AER).
- The total allowable revenues to be recovered by transmission businesses in aggregate would not change, however the way revenues are collected would change.[10]

1.4 Relevant background

In 1999, the National Electricity Code Administrator (NECA) proposed a change as part of its transmission pricing review that would have allowed transmission businesses to compute an inter-regional transmission charge for neighbouring regions[11]. The proposed approach put forward by NECA was rejected by the Australian Competition and Consumer Commission (ACCC) in its 2001 final authorisation decision.[12] The ACCC required NECA to undertake a further review but this review was never undertaken due to the National Electricity Law (NEL) changes that led to the transfer of NECA's responsibilities to the AEMC and the AER.

Over 2005-2006, the Commission undertook a review of electricity transmission revenue and pricing, as required under the NEL. In this review the Commission highlighted the problems associated with the absence of an inter-regional transmission charging mechanism, although it did not offer any recommendations at that time. The need for an inter-regional charging mechanism was considered in more detail in the National Transmission Planner (NTP) Review, which set out a number of possible high level options.[13] In response to the NTP final report the MCE requested that the Commission consider the need to improve the existing inter-regional transmission pricing arrangements as a part of the Review of Energy Market Frameworks in light of Climate Change Policies (Climate Change Review).[14]

In the final report on the Climate Change Review, the Commission recommended the introduction of an obligation on transmission businesses to levy a "load export charge"

9 There are existing provisions under the rules in clause 6A.29.1 for the appointment of coordinating network service providers.

10 The Commission notes that the rule proposed by the MCE would also change the way in which costs are allocated by transmission network service providers.

11 See NECA, Transmission and Distribution Pricing Review, Final Report, Volumes I-III, July 1999. All NECA reports are available at: http://www.neca.com.au/Reviewsdd14.html?CategoryID=51&SubCategoryID=2

12 ACCC, Amendments to the National Electricity Code, Network pricing and market network service providers, 21 September 2001, pp.59-60.

13 AEMC, 2008, National Transmission Planning Arrangements, Final Report to MCE, 30 June 2008, pp. 68-72.

14 The Hon Martin Ferguson AM MP, Chair MCE, Letter to Dr Tamblyn, Chairman AEMC, 5 November 2008. See www.mce.gov.au.

on the transmission business in each neighbouring region.[15] This charge would reflect the costs of providing transmission capacity to transport electricity into neighbouring regions.

In its policy response to the Climate Change Review, the MCE supported, in principle, the introduction of the load export charge and subsequently submitted the current rule change request to the AEMC for consultation.[16]

1.5 Commencement of rule making process

On 13 May 2010, the Commission published a notice under section 95 of the NEL advising of its intention to commence the rule making process and the first round of consultation in respect of the rule change request. A consultation paper prepared by AEMC staff identifying specific issues or questions for consultation was also published with the rule change request. Submissions closed on 24 June 2010.

The Commission received eight submissions on the rule change request as part of the first round of consultation. They are available on the AEMC website.[17] A summary of issues raised in submissions and the Commission's response to each issue is contained in Appendix A.1.

The publication of the draft rule determination had been extended under section 107 of the NEL on two occasions. Firstly a notice under section 107 of the NEL was published along with the consultation paper on 30 May 2010. This extended the time by four weeks to 30 September 2010. A second 107 notice was issued on 30 September 2010 extending the time by nine weeks to 2 December 2010.

1.6 First draft determination

On 2 December 2010, the Commission published the first draft rule determination and first draft rule. The first draft rule generally maintained the intent of the proposal in the MCE rule change request in terms of the composition of the load export charge and how it should be applied. However, the Commission also made some additional amendments:

- The drafting of the load export charge provisions were amended to improve clarity.
- The proceeds of settlement residue auctions would continue to be distributed to consumers in importing regions through the locational TUOS component.[18]
- New savings and transitional provisions were to be included in the rules that required the AER to amend its pricing methodology guidelines and transmission businesses to amend their pricing methodologies.

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15 AEMC 2009, Review of Energy Market Frameworks in light of Climate Change Policies: Final Report, September 2009, pp. 42-53.

16 MCE 2009, Response to the AEMC's Final Report on the Review of Energy Market Frameworks in light of Climate Change Policies, December 2009, pp. 7-8. See www.mce.gov.au.

17 www.aemc.gov.au

18 The MCE in its rule change request proposed that auction proceeds should be distributed to consumers in the importing region on a postage stamp basis

The Commission received 17 submissions on the first draft rule determination. Many submissions in response to the draft rule determination argued against the proposed design of the load export charge. Key issues raised were concerns over including non-locational components of TUOS services in the charge, as these were considered to serve no economic signalling function; and that transmission network service providers would use different transmission charging methodologies to calculate the charge, creating potential inconsistencies between regions.

After considering submissions and undertaking independent modelling, the Commission formed the view that the inconsistency in the way the load export charge would be calculated in each region would undermine the credibility of the proposed charging mechanism. As a consequence, in April 2011 the Commission extended the period for making its determination on the rule change request to consider these issues further and committed to developing a more uniform approach to inter-regional charging.

1.7 Discussion paper

Responses to the draft determination raised a number of complex issues requiring further consultation and consideration. A section 107 notice was issued to delay publication of the final determination and a subsequent discussion paper was published on 25 August 2011 further examining the range of issues identified in submissions to the draft determination.[19]

The discussion paper described several inter-regional charging options. These options are described in Chapter 4 of this final determination. In line with the rule change request, the scope of those options did not extend into changing the approach to the current intra-regional transmission charging arrangements.

The Commission received 9 submissions in response to the discussion paper. Most submissions were supportive of the modified load export charge, where it recovered the locational component of TUOS services only. There was also support for an alternative inter-regional charging approach based on cost sharing and market modelling to determine the cost shares. This was put forward by a group of generators[20]; and is described in Section 4.4 of this determination. It was also evaluated against the other inter-regional charging options in Chapter 6. The submissions are summarised in Appendix A.2.

1.8 Modelling options

The Commission engaged ROLIB Pty Ltd to model the different charging options and provide a measure of the relevant financial impact of each option on different regions.

The modelling showed that individual consumer impacts of introducing an inter-regional charge appear to be relatively modest, with the price change that would likely occur on the introduction of an inter-regional transmission charge being similar in magnitude to typical annual price variations that consumers face currently.

19 AEMC, Discussion Paper, 25 August 2011

20 The generators are AGL, Alinta, International Power, GF Suez and LYMMCo

There was some variation however between charging options in terms of the quantum and volatility of the charges. Four submissions were received on the modelling report; they did not identify any significant technical issues or errors with the modelling.

The results of the modelling have been published on the Commission's website and are discussed in Section 6.6. Submissions on the modelling report are summarised in Appendix A.3.

1.9 Second draft determination

The Commission released a second draft determination and supporting draft rule on the 2nd of December 2012. In this determination the Commission evaluated the options set out in the discussion paper and proposed to make a more preferable rule.[21]

The Commission considered a modified load export charge would better contribute to achievement of the National Electricity Objective. This decision also took into account the need to balance a range of factors including cost reflectivity, transparency, stability, implementation costs and the impacts of a new charge on consumers.

The Commission received 8 submissions on the second draft determination. No new matters of policy were raised, however a number of aspects of the draft rule were identified as in need of clarification and both the AER and Grid Australia sought to have the deadline for implementation of the rule extended to account for heavy work programs. These submissions are summarises in Appendix A.4

21 Under section 91A of the NEL the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that having regard to the issue or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the National Electricity Objective.

2 Final rule determination

2.1 Commission's determination

The Commission has now made this final determination in relation to the rule change proposed by the SCER. It maintains the position as set out in its second draft determination for a more preferable rule to implement a modified load export charge.[22]

The reasons for making a more preferable rule are set out in Chapter 3 and the final (more preferable) rule is attached to and published with this final determination.

The final rule contains a number of savings and transitional provisions to facilitate the introduction of a modified load export charge.

2.2 Commission's considerations

In assessing the rule change request the Commission considered:

- its powers under the national electricity law to make the rule;
- the rule change request;
- the fact that there is no relevant SCER Statement of Policy Principles;[23]
- submissions received at all stages of consultation; and
- its analysis as to the ways in which the proposed rule will or is likely to, contribute to the achievement of the National Electricity Objective.

2.3 Commission's power to make the rule

The Commission is satisfied that the final rule falls within the subject matter about which the Commission may make rules. Section 34(1)(a)(iii) of the NEL provides that the Commission may make rules for or with respect to the activities of persons (including registered participants) participating in the NEM or involved in the operation of the national electricity system. The final rule also falls within the matters set out in schedule 1 to the NEL:

- Item 16(1) - The regulation of prices charged or that may be charged by owners, controllers or operators of transmission systems for the provision by them of services that are the subject of a transmission determination; and

22 Under section 91A of the NEL the AEMC may make a rule that is different (including materially different) from a market initiated proposed rule (a more preferable rule) if the AEMC is satisfied that having regard to the issue or issues that were raised by the market initiated proposed rule (to which the more preferable rule relates), the more preferable rule will or is likely to better contribute to the achievement of the National Electricity Objective.

23 Under section 33 of the NEL the AEMC must have regard to any relevant MCE statement of policy principles in making a Rule.

- Item 20 - The economic framework, mechanisms or methodologies to be applied or determined by the AER for the purpose of items 15 to 16 including (without limitation) the economic framework, mechanisms or methodologies to be applied or determined by the AER for the derivation of the revenue (whether maximum allowable revenue or otherwise) or prices to be applied by the AER in making a transmission determination.

The Commission considers that the final rule falls within these subject matters as the final rule relates to the setting and regulation of transmission pricing.

2.4 Rule making test

Under section 88(1) of the NEL the Commission may only make a rule if it is satisfied that the rule will, or is likely to, contribute to the achievement of the National Electricity Objective. This is the decision making framework that the Commission must apply to rule changes.

The National Electricity Objective is set out in Section 7 of the NEL as follows:

> "The objective of this Law is to promote efficient investment in, and 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."

For this rule change request, the Commission considers that the relevant aspect of the National Electricity Objective is promoting the efficient investment in, and use of, electricity services.[24]

Under section 91(8) of the NEL the Commission may only make a rule that has effect with respect to an adoptive jurisdiction if it is satisfied that the proposed rule is compatible with the proper performance of the Australian Energy Market Operator (AEMO)'s declared network functions.

The final rule sets out a new process for transmission network service providers to recover costs in the form of a modified load export charge. AEMO, in its capacity as the transmission network service provider in Victoria, would be required to amend its pricing methodology in order to implement the final rule The final rule does not however impact on AEMO's obligations associated with respect to planning or providing shared transmission services.

For these reasons, the Commission considers the final rule is compatible with AEMO's declared network functions.

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24 Under section 88(2), for the purposes of section 88(1) the AEMC may give such weight to any aspect of the NEO as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles. As noted in section 2.2, there is no relevant Statement of Policy Principles.

2.5 More preferable rule

Under section 91A of the NEL, the Commission may make a rule that is different (including materially different) from a proposed rule if it is satisfied that, having regard to the issues or issues that were raised by the proposed rule (the MCE rule change request), the more preferable rule will or is likely to better contribute to the achievement of the National Electricity Objective.

Having regard to the issues raised by the rule change request the Commission is satisfied that the rule as made will or is likely to better contribute to the National Electricity Objective compared with the proposed rule because it:

- provides more efficient price signals;
- is calculated and applied in a more consistent way;
- provides for greater transparency and regulatory stability; and
- is more proportionate with respect to consumer impacts.

The Commission's assessment framework is set out in Chapter 5 and the options are assessed against this framework in Chapter 6.

2.6 Other requirements under the National Electricity Law

Under section 88B of the NEL, the AEMC must take into account the revenue and pricing principles in making a rule on any matter that relates to the revenue and pricing of the regulation of network businesses (these matters are listed in Schedule 1 of the NEL).

The Commission has taken into account the revenue and pricing principles in making this final determination as the final rule relates to items 16(1) and 20 of Schedule 1 of the NEL (noted in Section 2.3). The revenue and pricing principles require:

- that transmission network service providers are provided a reasonable opportunity to recover efficient costs and that prices allow for a return commensurate with the regulatory and commercial risks associated with in providing the service; and
- regard is had to the economic costs and risks associated with under or over utilisation of a transmission system which provides direct control network services to consumers.

The Commission considers that the final rule is consistent with the revenue and pricing principles as it improves the cost reflectivity of the prices charged by transmission network service providers, encouraging more efficient use of the transmission network, without impacting a transmission business's ability to recover efficient costs.

The final determination does not change the total amount of revenue allowed to be recovered by transmission network service providers. However, it would result in an ongoing redistribution of transmission charges.

3 Commission's reasons

The Commission has considered the rule change request proposed by the Ministerial Council on Energy. For the reasons set out below, it has determined to make a more preferable rule.

3.1 Rationale for introducing an inter-regional transmission charge

Current transmission charging arrangements do not fully reflect the interconnected nature of the National Electricity Market. A region that experiences imports does not incur charges that reflect the full costs associated with importing that energy. In its consideration of the rule change request the Commission addressed two separate but related questions:

- whether the introduction of an inter-regional transmission charge would promote achievement of the National Electricity Objective; and
- what form the inter-regional transmission charge should take in order to best meet the National Electricity Objective.

The Commission considers an inter-regional transmission charge will promote the National Electricity Objective for the following reasons:

- Transmission network service providers will have greater incentives to pursue efficient transmission investments for which the costs fall predominantly in their own regions and benefits fall in neighbouring regions. This is because they are able to recover some of the costs of the investment from the neighbouring regions.
- Prices consumers face for transmission services will be more reflective of the actual costs incurred in providing those services.
- Credibility of, and confidence in, regulatory arrangements is improved as the costs of transmission capacity used for conveying electricity between regions is allocated to the regions that derive benefits from such capacity.

3.2 Preferred inter-regional transmission charging option

The Commission has developed and analysed several design options for inter-regional transmission charges in accordance with assessment framework described in Chapter 5. It considers that a modified load export charging option provides the best balance relative to the other options considered with respect to meeting the assessment criteria, for the reasons that it:

- is calculated and applied in a more consistent way compared to the original load export charge as set out in the rule change request;
- is more consistent with allocating costs in line with beneficiaries over time relative to the group of generators proposal;
- provides for greater administrative simplicity compared to NEM wide cost reflective pricing approach and the group of generators proposal;
- is at least as good as the NEM-wide cost reflective pricing approach with respect to transparency and better than the other options; and

- is strongest of all options with respect to promoting regulatory stability and ensuring proportionate consumer impacts.

3.3 Differences between rule change request and final rule

Under the rule change request the load export charge would be calculated to recover a proportion of both the locational and non-locational components of prescribed common services and prescribed TUOS services in the neighbouring regions (relating to assets deemed to support inter-regional flows). Transmission network service providers would also have discretion to use their individual cost reflective pricing methodologies to calculate the inter-regional charges.

The Commission's preferred rule as set out in this final determination differs from the rule change request in the following key ways:

- A standardised cost reflective network pricing methodology will be used in calculating the inter-regional charge for each region.[25]
- The modified load export charge would recover a proportion of the locational component of TUOS services in a neighbouring region only.
- The proceeds of settlements residue auctions would continue to be redistributed to consumers in the importing region on a locational basis.[26]
- The charge would be exempt from the requirement to meet the annual 2 per cent side constraint in the rules. This means that increases to the volume weighted prices of prescribed TUOS services can exceed 2 per cent provided this occurs as a consequence of the modified load export charge.
- The coordinating network service providers for a region will be required to publish the calculated modified load export charge amounts by 15 March each year.
- Savings and transitional arrangements are implemented on 1 July 2014 in which the AER is required to publish an amended pricing methodology guideline that includes the new arrangements by the 30 September 2014; and
- Each transmission network service provider will need to prepare an amended pricing methodology consistent with the amended guideline by no later than 27 February 2015, or sooner on a best endeavours basis.
- The commencement date for the operation of the new arrangements would be July 2015.

25 All network costs are allocated in the same manner, each trading interval of the previous regulatory year is considered and peak usage of each asset is used for the allocation of generation to load

26 This redistribution of proceeds is consistent with the purpose for having inter-regional transmission capacity; which is to provide access for consumers in an importing region to lower cost energy in the exporting region. Further, distributing such benefits on a locational basis allocates those benefits on the basis of proportionate utilisation of transmission capacity. The Commission considers that the allocation of some of the energy market benefits of inter-regional transmission capacity in this manner is consistent with the Commission's proposed allocation of the costs of such capacity.

3.4 Stakeholder views

The Commission's assessment has taken into consideration issues raised in stakeholder submissions to the rule change process. The issues raised in submissions are discussed in the following chapters and a detailed summary of the issues, and responses and comments from the Commission, are outlined in Appendix A.

3.5 Civil penalties

Chapter 6A contains no civil penalty provisions. The Commission does not propose to recommend to the MCE that any of the proposed amendments in the second draft rule be classified as civil penalty provisions as the second draft rule relates to the TNSPs' pricing provisions under Chapter 6A of the rules. The financial nature of the provisions under Chapter 6A provides incentives to ensure that TNSPs adhere to the requirements so that their costs may be efficiently recovered.

4 Inter-regional charging options

In assessing the rule change request, the Commission has considered four different inter-regional transmission charging options:

- load export charge;
- modified load export charge;
- a proposal for cost sharing by a group of generators; and
- NEM-wide cost reflective network pricing.

These options were assessed against the status quo arrangements.

All regions both import and export electricity, therefore the charges applying to each transmission business under the cost reflective pricing options will be determined on a net basis. The net charges are then recovered from consumers.

4.1 Status quo

The status quo is a continuation of the existing arrangements for the recovery of costs associated with inter-regional transmission flows. So that recovery of these costs would be from consumers within the region of the transmission network provider only, with no change to the current pricing methodologies used.

4.2 Load export charge

Under this option, a transmission network service provider in each region calculates and levies a load export charge (the net of those charges) on transmission network service providers in neighbouring regions. The charge for a transmission business would reflect the costs of transmission assets located in the neighbouring region used for supporting electricity flows into its own region.

Cost reflective network pricing

Transmission businesses currently use cost reflective network pricing to allocate costs to consumer load points. This approach measures the level of peak utilisation of network elements and assigning costs on that basis (so that more of the costs are allocated to heavily loaded network elements).

There are two versions of cost reflective network pricing currently used in the NEM: the standard approach assigns the full optimised replacement costs of the assets to consumers; while modified cost reflective network pricing only allocates that proportion of the asset actually being used to individual consumer load points (with the remainder of asset costs recovered from the non-locational component of prescribed TUOS services). A full summary of the cost reflective network pricing methodology is contained in Schedule 6.4 of the rules.

Transmission network service providers also currently use two different measures of peak utilisation to assign costs:

- 10-day system peak method; and
- 365-day element peak method.

The 10-day system peak method is currently used by AEMO in Victoria. It takes the top ten system half-hour demand intervals over the last 12 months (which must occur on different days); measures transmission element[27] loadings during each of those ten half-hour intervals to determine a maximum loading for the purposes of assigning transmission costs. The individual contributions of consumers at connection points over the same time period is then measured so that transmission costs can be allocated to consumers on a proportionate basis. As a result, this method apportions transmission costs to loads on the basis of their contribution to system peak demand.

In contrast, the 365-day element peak method is used by the other transmission network service providers. It measures the peak loading on all elements supplying a load point over 365 days and determines the contribution of each load point to the total flows on each element at the time of peak load on that element (rather than at system peak). Costs are then apportioned to load in proportion to their contribution to the individual element's peak loading.

The methodologies for calculating the load export charge would be the same used by transmission network service providers currently to calculate charges for their within region consumers. This means that the methodologies for calculating the load export charge would vary between regions (ie the form of cost reflective network pricing used and the measure of utilisation).

Recovery of the charge

The draft rule determination prescribed how the charges levied on an importing transmission business would be recovered from that business's consumers. The prescribed locational TUOS service component of the load export charge would be added to the prescribed locational TUOS service component of the intra-regional transmission charge, and the prescribed non-locational TUOS service component of the load export charge would be added to the prescribed non-locational TUOS service component of the intra-regional transmission charge. In other words, the load export point is treated in the same way as all the exporting transmission network service provider's other intra-regional load points.

The load export charge as proposed in the rule change would recover from an importing region a proportion of prescribed locational and non-locational TUOS costs and the prescribed common transmission costs applied in the neighbouring exporting region. The charge would be recovered from importing regions consumers on the same basis as current intra-regional TUOS charges.

The draft rule determination supported the introduction of a load export charge, consistent with the MCE rule change request, but provided an amendment to the rule change request proposing that auction revenues be redistributed on a locational basis to importing region consumers rather than a non-location basis.

4.3 Modified load export charge

The modified load export charge is determined in a manner similar to the load export charge; but differs in a number of important respects. First, it requires a

27 Transmission elements are usually either lines or transformers

consistent pricing methodology is applied by transmission network service providers in each region. That is, the same form of cost reflective network pricing and approach to measuring peak utilisation should be applied by all transmission businesses in calculating the charge. The Commission has decided on the standard cost reflective pricing approach for calculation of a modified load export charge and the 365 day peak element (capacity) approach for measuring utilisation. The Commission's reasons are set out in Chapter 6.

A further important aspect of this approach is that the modified load export charge would be calculated separately from calculation of intra-regional transmission charges, so that transmission network service providers could retain their individual pricing methodologies for transmission assets that do not contribute to inter-regional flows.

Operationally this would occur as follows. The transmission network service provider would undertake one application of its cost reflective network pricing methodology for intra-regional load points according to current arrangements in which no inter-regional load points would be included. The transmission network service provider would then perform an additional run of the cost reflective network pricing methodology (based on standardised components) including the export load point (or points, depending on how many neighbouring regions there were). This second application of the cost reflective network pricing methodology would only have the function of producing a charge for the importing regions.

Recovery of the charge

A modified load export charge can be implemented to recover either the locational component of prescribed TUOS services or all relevant components (locational, non-locational and common services components). The Commission has decided that the modified load export charge should only recover the locational component. This component would then be allocated to consumers on the basis of their proportionate utilisation of intra-regional transmission capacity.

4.4 Cost sharing

Under this option assets associated with inter-regional flows are identified and then the costs are apportioned between different regions on some basis. The interconnector cost share is then recovered by each transmission network service provider from its own consumers in some manner. In practice, all of the options discussed above do this; however, under the cost-sharing option the allocation across regions is determined in advance and fixed for the duration of the asset life.

There are two steps required under this approach:

- identifying interconnector assets for which costs are to be shared; and
- determining how the cost of those assets should be split between regions and allocated to consumers.

There is a range of ways for undertaking these two steps, which are discussed in detail the discussion paper. One option was proposed by the "group of generators"[28] and contains the following key elements:

- Only the costs of "new" assets (ie those developed and commissioned after the implementation of the inter-regional transmission charge approach) are allocated between regions.
- A market modelling approach similar to that which underpins the regulatory investment test - transmission (RIT-T) is used to estimate the market benefits of new transmission assets and in which regions the market benefits are estimated to be derived.
- Costs are allocated to each region in proportion to modelled market benefits.
- The cost-allocation would be determined and agreed between relevant transmission network service providers ex ante: that is, before the new asset was developed.
- The cost-allocation would then generally be fixed for the life of the asset, regardless of actual inter-regional flows, although in exceptional circumstances it may be possible to "re-open" and vary the cost-allocation at a later time.

The applicable annual revenues associated with the interconnector assets would be shared in accordance with the agreed allocation.

Recovery of the charge

The group of generators specified that the charge would be recovered from consumers on a postage stamp basis.

4.5 NEM-wide cost reflective network pricing

This option is an extension of the modified load export charge, creating a single nationally consistent NEM-wide transmission charging methodology.

Like the modified load export charge this approach would use a separate methodology for charging for those assets supporting inter-regional flows versus those intra-regional assets that support within region flows only. In contrast to that approach, however, in this option the charging methodology is applied once, on a NEM-wide basis, rather than being applied separately by each transmission network service provider for assets in its region. The charge levied for a particular consumer would reflect that consumer's utilisation of all assets within all regions of the NEM (including non-neighbouring regions).

The locational component for prescribed transmission services would be determined across the NEM based on the cost of all transmission network assets in the NEM rather than just those within a region (as occurs under the status quo). This would require a NEM wide assessment of utilisation, and therefore potentially also a central body to administer the levying of the inter-regional charge. This body might be AEMO or

28 AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo, Response to the AEMC's discussion paper, 23 September, p1

another body established jointly by transmission network service providers for the purpose of applying the methodology and levying the charge.

The NEM cost reflective pricing approach to determining an inter-regional charge is best demonstrated with an example. An asset in region A may have a total optimised replacement cost of $100,000. On the basis of measuring utilisation (using cost reflective pricing) $70,000 of that asset is allocated to consumers in region A, $20,000 to region B and $10,000 to region C. The $20,000 allocation contributes to the inter-regional transmission charge payable by the transmission network service provider in region B to the transmission network service provider in region A. The $10,000 allocation contributes to the inter-regional transmission charge payable by transmission network service provider in region C to the transmission network service provider in region A.

Recovery of the charge

As with the other cost reflective pricing-based options, inter-regional charges are aggregated and netted off against one another, to determine the amounts payable bilaterally between transmission network service providers. Net amounts are then recovered through adjustment to intra- regional locational TUOS charges (based on utilisation of the network).

5 Commission's assessment approach

This chapter describes the assessment framework that the Commission has applied to assess the rule change request in accordance with the requirements set out in the National Electricity Law (as explained in Chapter 2).

5.1 Assessment criteria

In evaluating which option as a more preferable rule better achieves the National Electricity Objective, the Commission considered the following assessment criteria:

- Efficient transmission pricing
- Regional beneficiaries pay
- Regulatory stability
- Administrative efficiency
- Transparency
- Consumer impacts

Pricing efficiency relates specifically to cost reflectivity of charges. The other criteria focus on promoting the efficiency of regulatory arrangements. The Commission considers this is important for engendering confidence in, and credibility of, regulatory arrangements (in turn promoting efficient operation of associated markets). These assessment criteria are briefly outlined below.

5.1.1 Efficient transmission pricing

Promotion of efficiency for the long term interest of consumers lies at the heart of the National Electricity Objective. There are three components to efficiency:

- Productive efficiency - occurs when firms using given inputs and technologies produce the goods and services they offer to consumers at 'least cost'.
- Allocative efficiency - occurs where resources are allocated to the uses most valued by society (which means they will deliver the greatest possible benefit to society). Allocative efficiency requires that energy services are provided, and consumption decisions are made, on the basis of prices that reflect the opportunity (or marginal) costs of goods and services; and that energy services are both provided and priced in line with the preferences and valuations of consumers.
- Dynamic efficiency - ensures productive and allocative efficiencies are achieved over time, taking account of technological change and innovation. Dynamic efficiency requires firms to adapt to changing consumer preferences and productive opportunities over time.

All three components are reflected in the National Electricity Objective, as changes to rules must promote efficient operation (productive efficiency); use of (allocative efficiency) and investment (dynamic efficiency) in electricity services.

Allocative and dynamic efficiency are supported by prices that reflect the full costs of the resources used to produce goods and services. Where costs are allocated to those who cause them this provides incentives for scarce resources to be used more efficiently. This is because those who cause costs to be incurred are usually in the best position to respond in ways that reduce or minimise such costs over time.

Further, prices should to the extent possible reflect future costs (rather than past costs or sunk costs) as these are the costs that consumers have greatest prospect of influencing. Given the long lived nature of transmission assets and the planning horizons involved for investing in transmission, prices should reflect the long run marginal cost of the provision of network services.

Currently, consumers located in regions that import energy do not pay the full costs associated with conveyance of electricity to their locations. Introducing an inter-regional transmission charge seeks to address this issue.

5.1.2 Regional beneficiaries pay

Stakeholders may be more likely to support regulatory arrangements that link costs with benefits relative to those that do not. It is likely new costs or a reallocation of costs will achieve greater acceptance by consumers and stakeholders if they perceive a commensurate level of benefits associated with the cost being incurred.[29]

The Commission considers therefore that the allocation of transmission costs through an inter-regional charge between regions (ie between consumers in aggregate in each region) should be broadly commensurate with the perceived regional allocation of benefits of transmission. This promotes confidence in regulatory arrangements.

5.1.3 Regulatory stability

Changes to arrangements should be manageable and understandable by stakeholders, commensurate with perceived benefits and proportionate to the problem being addressed. Regulatory changes that overreach, are duplicative or are inconsistently applied reduce regulatory credibility and create a less stable regulatory environment. Lack of stability in arrangements can affect confidence of stakeholders to invest and participate in associated markets (dynamic efficiency).

5.1.4 Administrative efficiency

There are often indirect consequences that arise from introducing a new set of arrangements (in economics called transactions costs) that must also be taken into account to ensure such arrangements do not create issues or distortions elsewhere in the energy supply chain.

29 Case law from the United States of America has established that the Federal Energy Regulatory Commission (FERC) cannot approve a transmission pricing scheme that requires parties to pay for facilities from which they derive no benefits, or face charges where the benefits to them are trivial in relation to the costs sought. FERC has adopted these principles in its order No. 1000, issued in July 2011, and recently confirmed them after considering submissions. See Illinois Commerce Commission v FERC, 576 F.3d 470, 476

With respect to the current rule change request these consequences include the implementation and administrative costs for transmission service providers and network users in calculating a potentially complex new charge (for instance requiring implementation of new methods, procedures, systems, models and training etc.) and the impacts of a new charge on the ability of a firm to understand or predict its financial exposures over time. Further, inconsistent arrangements between different regions with respect to how an inter-regional charge is applied adds costs for stakeholders who are required to understand these difference and ensure their systems and processes can accommodate them.

5.1.5 Transparency

The way charges are derived and applied (including any cross-subsidies) should be transparent to consumers so they can effectively adjust their behaviour in ways that reduces those costs. Transparency in regulatory arrangements (for example, with respect to costs and benefits and where they fall) enhances the credibility of and confidence in regulation, supporting efficiency of associated markets.

5.1.6 Consumer impacts

While it is important that charges are cost reflective they should not be excessively volatile or onerous and should be implemented in a way that provides a reasonable opportunity for consumers to respond.

6 Assessment of the inter-regional transmission charging options

In this chapter we evaluate the inter-regional transmission charging options with respect to each of the assessment criteria discussed in Chapter 5. The Commission also sets out its reasoning in this chapter for choosing the modified load export charge.

The Commission received submissions to a consultation paper, draft determination, discussion paper and second draft determination. These are summarised in Appendix A, which includes our responses to these submissions. Here we discuss issues raised in submissions that bear directly on the specific assessment criterion being considered.

6.1 Pricing efficiency

An efficient transmission price would reflect all costs incurred in providing the transmission service to that consumer and ideally this should be signalled in the way that allows consumers to effectively respond to such costs. All inter-regional options are considered to be an improvement over the status quo, given that under the status quo there is no price signalling of inter-regional costs.

6.1.1 Stakeholder views

Submissions to the rule change request raised a range of considerations in relation to the pricing efficiency of the charging options considered. These can be summarised as follows:

- The role of cost reflective network pricing.
- The ability of consumers to respond to an inter-regional transmission charge.
- Whether sunk costs should be included in the charge.
- Impact of an inter-regional charge on the wholesale market.
- How an inter-regional charge should be recovered from consumers.

Role of cost reflective network pricing

In its submission to the draft rule determination, the MEU argued the cost reflective network pricing methodology did not provide efficient forward looking signals.[30] It also considered the use of cost reflective pricing more generally did not "recognise that interconnection assets provide non-price benefits, such as increased reliability."[31]

The group of generators, in a submission provided in response to the discussion paper, also did not support use of cost reflective pricing in determining the charge, because they considered it was based on allocating the costs of existing assets, and therefore offered little in the way of economic signalling.[32] They proposed an approach where an inter-regional charge was based on allocating the costs of new inter-regional assets

30 MEU submission to draft determination, February 2011, p 4

31 MEU submission to draft determination, February 2011, p 4

32 Group of generators submission to the discussion paper, 23 September 2011, p 2

before they are built. Costs would then be recovered in accordance with the "purpose of the investment, and not on the essentially cost-free opportunistic use of transmission assets once they exist"[33].

While most stakeholders appeared supportive of the use of cost reflective network pricing in determining inter-regional charges. Many raised concerns however with regard to the potential for inconsistent application of this approach across different regions. In response to the discussion paper AEMO noted that "differing valuation and apportionment methodologies between those regions will cause consumers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours."[34]

For this reason few stakeholders supported the original load export charge, which allowed for such discretion to be applied with respect to determining an inter-regional charge. A central theme in submissions was that an inter-regional charge should be calculated consistently across different regions. Both AEMO and TRU Energy supported the NEM wide cost reflective network pricing option for this reason.[35]

No submissions expressed a strong opinion on whether cost reflective network pricing or modified cost reflective network pricing should be preferred for calculating an inter-regional charge. Grid Australian in a submission to the draft determination did not consider the use of the modified version would make a material difference to the quantum of charges.[36]

There were a range of views expressed however on what measure of utilisation should be used in the charging approach. In a submission to the draft determination AEMO supported a system peak approach to assessing utilisation because they considered this approach reflected the key drivers for network investment.[37] In contrast, Grid Australia considered an element peak approach was more consistent with the cause of network investment.[38]

Ability of consumers to respond

The MEU argued in its submission to the discussion paper that there may be little value in consumers facing an inter-regional transmission charge, because they are unlikely to be able to influence the quantum of the charges they face.[39] They considered this to be the case for two reasons. First, an inter-regional charge based on cost reflective network pricing would allocate costs on the basis of flows; such flows however are determined by bidding behaviour and locational decisions of generators, over which consumers have no control. Second, existing consumers would have little capacity to respond to a transmission charge because their investment is mostly sunk. The efficiency properties

33 Group of generators submission to the discussion paper, 23 September 2011, p 2

34 AEMO submission to the discussion paper, 4 October 2011, p 4

35 AEMO submission to the discussion paper, 4 October 2011, p 6; TruEnergy submission to the discussion paper, 23 September 2011, p2

36 Grid Australia supplementary submission to the draft determination, 7 March 2011, p 3

37 AEMO submission to the draft rule determination, 25 February, p 2

38 Grid Australia supplementary submission to the draft determination, 7 March 2011, pp 2- 3

39 MEU submission to discussion paper, 23 September 2011, p 7

of all of the inter-regional charging options under consideration are therefore negligible.[40]

Inclusion of sunk costs

The original load export charge sought to recover both the locational and non-locational costs of transmission assets associated with supporting inter-regional flows. It did not distinguish between new or old assets. The majority of submissions did not support inclusion of non-locational costs in an inter-regional transmission charge however. The response by the Victorian Department of Primary Industries to the draft determination reflected sentiments expressed in many submissions that "changing which consumers pay for the recovery of sunk costs will not promote efficient future investment nor enhance dynamic efficiency."[41]

The group of generators considers an inter-regional charge should be determined before the investment takes place as there is "no justification in terms of the NEO in now undoing these past decisions [to construct interconnectors], by re-allocating these historical and sunk costs."[42] The group of generators preferred approach was to determine an upfront charge for new investment only.

Interaction with wholesale market

In its submission to the draft rule determination the MEU argued that the Commission had not adequately considered the development of an inter-regional charge in a holistic fashion with respect to the wholesale market[43]. In particular they noted that when the cost of an inter-regional charge is added to cost of imported generation, the total cost may not always be lower than the cost of local generation. In such circumstances introducing an inter-regional charge would undermine the National Electricity Objective. They provided some quantitative analysis to support their views in a submission to the second draft determination.[44]

Recovery of the charge

Most submissions did not comment directly on how an inter-regional charge once it is determined, should be recovered from consumers in the importing region. The group of generators proposed under its approach that the investment costs would be recovered on a non-locational basis (that is, as a postage stamp).

Grid Australia, in its submission to the second draft determination, noted that recovering such a charge on a locational basis from consumers under existing methodologies would allocate the costs on the basis of intra-regional utilisation and not a consumer's use of inter-regional assets.[45] They considered this would have the effect of diluting the price signal with respect to inter-regional asset costs.

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40 MEU submission to discussion paper , 23 September 2011, p 7

41 Vict Department of Primary Industries submission to draft rule determination, 25 February, p 6

42 Group of generators, submission to the discussion paper, 23 September 2012, p 2

43 MEU submission to the draft rule determination , 25 February, p 9

44 MEU submission to the second draft determination, January 2013, pp 16-18

45 Grid Australia submission to the second draft determination, 18 January 2013, p 3

6.1.2 Commission's analysis

Role of cost reflective network pricing

The Commission recognises that cost reflective network pricing may not be a perfect proxy for signalling the long run marginal costs of the network, because it is based on allocating the costs of existing assets, not future assets. It provides a reasonable proxy nonetheless, because it allocates costs on the basis of peak utilisation and electrical distance from generation sources. Both factors are significant drivers of future network investment.

While the Commission considers there may be scope for reviewing the effectiveness of cost reflective network pricing as means for efficiently signalling costs, it considers this is best undertaken as part of a broader review of transmission pricing. Implementing more fundamental reforms to pricing methodologies is beyond the scope of the current rule change request.

The group of generators offered an alternative to the use of cost reflective network pricing for calculating inter-regional charges. They propose this should be done using market modelling before an investment takes place, with costs allocated on the basis of which regions are deemed to benefit from the investment.

The Commission considers that a key weakness of this approach is the significant uncertainty associated with modelling the spread of benefits before the assets are built. This would need to be done on forecast direction of flows, which could potentially change with each new investment in generation or load, as well as depending on the bidding behaviour of generators which is notoriously difficult to model.

Consequently, there would be a substantial risk for long lived transmission assets that costs of a long lived asset will become misallocated over time, given the likelihood that beneficiaries will change over time. Further, in light of such uncertainty surrounding calculating future benefits, obtaining agreement on cost sharing between different jurisdictions before such assets are built under the RIT-T process is likely to be challenging and could delay projects while disputes over benefit allocation are resolved.

Cost reflective pricing approaches

A further consideration for the Commission was whether cost reflective network pricing or modified cost reflective network pricing should be used for the purposes of calculating the charge. Modified cost reflective network pricing can be considered to be more reflective of long run marginal costs, because it discounts transmission charges based on the level of excess transmission capacity in different parts of the network. This should encourage more efficient locational decisions, because consumers will have incentives, all other things equal, to locate in areas where there is spare capacity.

However, modified cost reflective network pricing would also be more complicated to apply than the standard cost reflective network pricing approach, as a certain level of subjectivity would be required to establish line ratings under a range of operating conditions for shared parts of the network contributing to inter-regional flows. These line ratings would be used by the transmission networks service provider as part of the process to determine the level of utilisation on a line. On balance we consider that the subjectivity inherent in such a process is unlikely to outweigh the benefits the modified cost reflective network pricing approach would deliver for calculating an inter-regional charge.

This was supported by modelling done by ROLIB Pty Ltd, which illustrated that the use of cost reflective network pricing versus modified cost reflective network pricing would not lead to significant differences in the quantum of cost allocations, primarily because excess capacity is expected to be a factor on radial transmission lines in parts of the network more remote from inter-regional transmission assets.[46]

Peak utilisation measures

The Commission was also required to make a decision on what measure of peak utilisation to incorporate in the inter-regional pricing methodology. A measure based on system peaks has intuitive appeal, because it is usually at times of peak system demand that congestion occurs on the network, and congestion is an important driver of investment in the shared network. The Commission considers an element peak approach has number advantages over system peak approach however:

- it is less arbitrary than the system peak method, because there is no requirement to choose peak days for allocating costs, and thus inadvertently choosing winners and losers on the basis of the days chosen;
- it takes into account a much broader range of operating conditions for which investment in networks is typically considered. It is consequently more consistent with the drivers for network investment; and
- consumers may find it easier to respond to a charge based on element peak utilisation which is more closely related to their own peak demand relative to a charge which is based on their contribution to system peak demand (consumers can predict their own behaviour better than collective system behaviour).

Ability of consumers to respond

An important requirement for achieving efficiency is that network users have the ability and incentive to respond to any price signal generated by a charge. Absent any potential for response there will be no improvement in efficiency.

The Commission considers that it is mostly large consumers that will have the incentive and ability to respond to an inter-regional charge (which will form a component of the intra-regional transmission charge). They can avoid such a charge by locating or relocating to the exporting region, and because such charges are recovered on the basis of peak utilisation, they can reduce their future exposure to such charges by improving their load factor.

A further strength of recovering the charge on a locational basis is that it sharpens existing signals for large consumers to locate closer to generation sources. Cost reflective network pricing charges are based on the notion that if the transmission prices are used to pursue least distortionary cost recovery only, then transmission consumers may locate in areas remote from generation sources. This would increase the need for

[46] ROLIB Modelling report, p 13

network investment and lead to inefficiently high network costs over time. Using cost reflective network pricing as a basis for allocation of an inter-regional charge on a locational basis ensures this signal is maintained and strengthened.

Inclusion of sunk costs

In principle, an efficient network price would require both a long run marginal cost based charge and a fixed postage stamp charge to ensure recovery of costs for a transmission network service provider.[47] In the context of an inter-regional transmission charge however, there is no efficiency gain from including sunk costs in the charge, because they are already being recovered from consumers within the exporting region. In other words, because there is no risk of a transmission business failing to recover all of its costs, the basis for including sunk costs in the inter-regional charge is lost. From an efficiency perspective, this would support an inter-regional charge being focused on recovering the long run marginal costs of the network only. The Commission considers that locational component of prescribed transmission services provides a good proxy for long run costs.

Interactions with the wholesale market

The Commission considers that a competitive National Electricity Market ensures that energy flows between regions is normally efficient (that it flows from regions with low cost generation to regions of higher cost generation). In addition, the RIT-T process requires that transmission investment is only built if it is efficient from an overall market perspective. For these reasons, the Commission is satisfied that while separately imposed on consumers, an inter-regional transmission charge should not distort the wholesale energy market.

In this regard the Commission considers the example provided by MEU in its submission to the second draft determination does not shed light on the MEU's concerns, because it assumes that energy offers of local generation would be the same in the absence of inter-regional transfer capacity. This is unlikely to be the case however, since generation offers in an importing region would be higher in the absence of an interregional connection. One of the benefits of inter-regional transmission capability is that it provides competitive discipline on the bidding behaviour of generators in all regions connected by that capability

Recovery of the charge

The Commission recognises that under its preferred approach recovery of the inter-regional charge would be on the basis of intra-regional utilisation rather than inter-regional utilisation. The Commission decided on this approach because it better reflects the fact that all consumers derive benefits from (or can be considered to have caused the need for) inter-regional capability, not just those located near the border. Even those consumers remote from the border benefit from reliability and competition benefits of transmission (discussed in more detail in 6.2). Further, as illustrated in Grid

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[47] Networks are subject to natural monopoly characteristics, which create a tension in achieving allocative and dynamic efficiency objectives. These characteristics, such as economies of scale and scope, mean that long run marginal costs are below average costs. Consequently, prices that are set purely on the basis of long run marginal costs would not recover the full costs of the network. This would undermine future (investment incentives for transmission businesses, as may be disinclined to invest in new assets if they are unable to recover the costs of the investment.

Australia's submission to the second draft determination, identifying precisely which consumers utilise inter-regional capacity and allocating costs on that basis requires a significantly more complex allocation methodology.

6.1.3 Conclusions on pricing efficiency

The group of generators' proposal is the only option under consideration that does not use cost reflective network pricing as a proxy for signalling long run marginal costs. While it has merit from a price signalling perspective in that it focuses on future costs, its dependency on allocating costs on the basis of market modelling creates a substantial risk that costs are misallocated over time.

The Commission concludes that cost reflective network pricing using an element peak (capacity) approach for measuring utilisation provides a better proxy of for signalling long run marginal costs of the network. Further, only locational costs should be recovered by the cost reflective pricing methodology, given the lack of economic signalling of including non-locational TUOS services. Both the modified load export charge and NEM wide pricing methodology are consistent with these requirements.

The Commission is also satisfied that use of cost reflective pricing for allocating costs will provide some incentives for consumer responses at the margin (large consumers) which will generate efficiency gains over time.

6.2 Regional beneficiaries pay

Regional beneficiaries pay means that consumers in a region contribute to the cost of an asset in proportion to the perceived benefits they are deemed to receive from it. This engenders confidence in regulatory arrangements and is consistent with outcomes in competitive markets. There are a range of benefits delivered by transmission assets that support inter-regional flows, including access to lower cost generation capacity, competition and reliability (reserve sharing) benefits.

6.2.1 Stakeholder's views

The MEU, in its submission to the second draft determination, noted that inter-regional transmission charge options based on cost reflective network pricing would not be consistent with allocating costs on a beneficiary pays basis, because it would lead to outcomes that potentially some regions pay higher charges despite prevailing flows being in the opposite direction.[48]They also note that none of the inter-regional transmission charge options considered adequately accounted for reliability benefits derived from inter-regional transmission capability. The MEU did not offer a coherent alternative to any of the options under consideration for an inter-regional transmission charge.

The Government of South Australia, also responding to the second draft determination, proposed that an energy based rather than capacity based approach should be used for measuring utilisation under cost reflective network pricing methodology, as a capacity based approach would not allocate costs in line with energy exports. They consider the key reason why SCER sought the introduction of and inter-regional transmission

48 MEU submission to the second draft determination, January 2013, p 13

charge was to allow regions to pass through transmission investment costs that arise from the need to export large amounts of renewable energy due to environmental policies.[49]

The group of generators argued that a cost-sharing approach based on market modelling would be the best way of allocating the costs of inter-regional transmission assets between regions. They proposed that the ex-ante benefit analysis should use a similar modelling approach to that used for the RIT-T. The cost allocation would be locked to that ex ante benefit analysis, except under specified circumstances where the costs might be re-allocated.

AEMO noted that "if agreement could be reached, [cost sharing] could be the most accurate way of allocating interconnecting costs to the beneficiaries of the interconnector."[50]

6.2.2 Commission's analysis

Cost reflective network pricing, based on a capacity based approach to measuring peak utilisation, would assess the peak use made by an importing region of assets located in a neighbouring region for conveyance of imports. This would have the effect of allocating costs based on peak use and not the frequency flows from one region into another. Thus a particular region may face a positive inter-regional transmission charge despite export flows exceeding imports for that region. This is demonstrated in modelling outcomes discussed in Section 6.6.

The Commission considers that a capacity based approach to assessing peak use better reflects the rationale for having inter-regional transfer capability; which is not just providing access to low cost generation capacity in other regions, but also to secure reliability and competition benefits.

The benefits of reliability are related more to peak requirements than frequency of energy flows. Peak capacity may not be used frequently but its value will be very high if it avoids sustained prices at the market price cap or load shedding. This is reflected in the investment drivers for transmission network service providers, who invest to meet peak demand requirements, not average demand (in order to avoid load shedding).

A further important benefit of transmission is its ability to connect geographically dispersed generation sources so that they can compete for supply. Again this benefit is largely independent of the direction of energy flows. Part of the reason for why a region may be exporting, for instance, is because potential and actual competition from generation in the importing region forces generators in the exporting region to bid closer to their marginal costs.

The Commission considers therefore that the peak capacity approach reflects a better proxy for capturing reliability and competition benefits relative to an approach that measures energy flows. The capacity approach is also consistent with the methodologies used by the majority of transmission businesses for calculating their intra-regional charges.

49 Government of South Australia submission to second draft determination, 7 February 2013, p 2

50 AEMO, submission the AEMC's discussion paper p 2

The inter-regional cost sharing approach proposed by the group of generators can also be considered to satisfy the regional beneficiary pays criterion, although only for new assets. This however ignores that consumers in importing region derive a significant benefit from existing inter-regional transmission capacity as well. Further, as argued previously, the beneficiaries' criterion under the group's proposal is likely to be unstable, with the beneficiaries changing over time. Making the cost allocation dynamic whether through a regular recalculation or in response to "re-opener" criteria as proposed by the group would address this flaw, but at the expense of significant additional administrative complexity.

6.2.3 Conclusions on regional beneficiaries pay

The Commission considers that a capacity based approach to assessing utilisation under a modified load export charge is more consistent with regional beneficiary pays than energy based approach (which allocated charges on the basis of energy flows between regions). The former approach underpins our preferred model for a modified load export charge.

Further, while the group of generators' proposal for cost sharing prima facie also has merit in allocating costs on a regional beneficiary pays basis, the lack of stability of beneficiaries over time weakens the approach.

6.3 Transparency

Transparency is important for consumers to be able to understand the charges to which they are exposed and respond to them. Transparency makes future prices more predictable, which allows long-term decision making (e.g., choice of location) by consumers in response to those anticipated prices. More broadly, transparency of regulatory arrangements also underpins confidence in and credibility of regulatory arrangements.

There are two aspects of transparency that are relevant to the rule change request:

a) network prices and the methodology used to arrive at those prices should be easy to understand by consumers ; and

b) the methodology used to arrive at those prices should be applied in a consistent fashion.

6.3.1 Stakeholder's views

Stakeholders were concerned that methodological inconsistencies across transmission network service providers' pricing methodologies would lead to a loss of transparency. Under the load export charge, transmission network service providers would be given discretion to implement variations in cost reflective network pricing methodology consistent with their intra-regional pricing approaches. The majority of stakeholders disagreed with this approach, because they considered this could lead to inconsistent application of inter-regional transmission charge across NEM states, with the charge varying on the basis of methodology rather than cost.

In its submission to the discussion paper TruEnergy noted that, "The original load export charge was simpler to implement but the inconsistencies in how key elements to transmission pricing were to be applied cast doubt on the validity of the pricing under that method."[51]

Other approaches, such as modified load export charging option, are based on a different approach used for calculating the inter-regional transmission charge versus intra-regional approaches. In this regard the Tasmanian Office of Energy Planning and Conservation (OEPC) noted in its response to the discussion paper that: "Consumers and stakeholders may find differences in method between intra and inter regional charging confusing, adding to an already complex system of calculating prescribed transmission charges."[52]

The group of generators argued that a cost-sharing approach is more transparent relative to cost reflective network pricing based approaches because "it is based on the transmission planning process which is already significantly transparent; it adds a further level of transparency in requiring an independent review; it involves a small number of individually significant decisions, and is thus inherently more open to scrutiny than multiple small decisions, especially if these frequent decisions were to involve complex calculations as the other options proposed would require."[53]

6.3.2 Commission's analysis

The most significant outcome from the application of an inter-regional transmission charge will be the net payment from one transmission business to a neighbouring transmission business. The net payment from transmission business A to transmission business B is the difference between:

- The inter-regional transmission charge calculated by transmission business B as payable by transmission business A; and
- The inter-regional transmission charge calculated by transmission business A as payable by transmission business B.

If these two components are calculated using different cost reflective network pricing methods, then part of the net payment is as a result of the differences in the methods rather than the underlying fundamentals. The Commission undertook some modelling to see how variations in cost reflective network pricing methodology could lead to different pricing outcomes. This is illustrated in Table 6.1

Table 6.1 Inter-regional transmission charge outcomes using different cost reflective network pricing methods ($M annual average)

Method	NSW pays VIC gross	Vic pays NSW gross	NSW Pays Vic Net
modified load export charge using 365 peak element method	32	25	+7

51 TruEnergy, submission to the discussion paper, 23 September, p2

52 OEPC submission to the discussion paper, 23 September 2012, p5

53 Group of generators submission to the discussion paper, 23 September 2012, P 8

Method	NSW pays VIC gross	Vic pays NSW gross	NSW Pays Vic Net
modified load export charge using 10 days system peak	0	4	- 4

The 365 day interval capacity element method is currently used intra-regionally in NSW and the 10 day peak interval energy element method intra-regionally in Victoria. As observed in the table, using one or the other method can lead to significant difference is in pricing outcomes. The Commission is persuaded therefore that a consistent cost reflective network pricing methodology will form an important component to the inter-regional transmission charge.

In principle, the NEM wide cost reflective network pricing approach would create the most consistent approach to calculating an inter-regional transmission charge, however a number of issues were identified in the modelling which would make such an approach difficult to implement (for instance the need for a NEM wide consistent replacement cost methodology). These are discussed in Section 6.5.

The Commission notes that the modified load export charge and NEM wide cost reflective network pricing would all require a separate calculation to be performed for calculating the inter regional and intra-regional charge. The Commission agrees this creates a level of inconsistency between intra-regional and inter-regional charging approaches. While in theory cost reflective network pricing could be applied in a way that would remove this distinction, this would require significant changes to be made to intra-regional charging approaches for some transmission businesses. This is beyond the scope of the current rule change consultation.

Transparency associated with the group of generators proposal

The RIT-T based cost-sharing approach has two main components:

- identify new “inter-regional” assets that are to be developed, having passed a RIT-T test; and
- allocate the costs of the assets between regions, based on the expected regional distribution of benefits provided by those assets.

A key benefit of the group of generator's proposal for cost sharing is that it would integrate calculation of inter-regional transmission charge with the RIT-T. The RIT-T is premised on creating a transparent process with significant stakeholder involvement in determining the cost and benefits of new investments. Allocation of costs of investment are under this process is likely to be reasonably transparent, with costs allocated ex ante and with substantial opportunity for consumer engagement.

Thus, cost-sharing will be relatively transparent at the time that the cost allocation is determined. However, if that cost allocation is then fixed for an extended period that transparency will erode over time. For example, a consumer in 2035 may be paying an inter-regional transmission charge based (to some extent) on a cost allocation that was agreed and fixed in 2015. Clearly, that consumer is unlikely to have any knowledge or understanding of that historical cost allocation decision and may question its relevance to present-day pricing, particularly where there have been significant changes in direction of network flows over time so that the original basis on which the costs were allocated no longer holds.

A similar situation could arise if a consumer signed a long term contract in 2015: e.g. a connection agreement with a term of 30 years. But the two contexts are fundamentally different. In the case of inter-regional transmission charge, there was no agreement from consumers, in 2015, to lock themselves into long-term cost sharing. Rather, the transmission network service provider has built a long-lived asset on the expectation that the asset will continue to be useful in providing transmission services to consumers over the life of the asset.

6.3.3 Conclusions on transparency

It is important for transparency that consistent methods are applied by all transmission network service providers in calculating gross inter-regional transmission charge. If there is inconsistency between methods, then the net inter-regional transmission charge may simply reflect methodological differences rather than fundamentals and be practically impossible for stakeholders to understand and predict. Therefore, in this respect, the load export charge is inferior to the other cost reflective network pricing options.

The cost-sharing option provides the most transparency of all the options at the time that the cost allocation decision is made. However, because the cost allocation is then generally fixed for the life of the assets (i.e. for several decades) the historical decision will become less transparent and irrelevant for future consumers.

The Commission concludes therefore that the modified load export charge and NEM-wide cost reflective pricing approach are most consistent with supporting transparency.

6.4 Regulatory stability

Regulatory stability requires that changes to rules or market arrangements are proportionate to the issues being addressed, consistently applied and transparent. All of the assessment criteria used for evaluating the inter-regional transmission charge options contribute to regulatory stability. Here we focus specifically on the issue of consistency of arrangements. Any changes made to arrangements should be consistent with changes being contemplated in other reviews (in particular the Transmission Frameworks Review) and not duplicate or undermine either existing or future regulatory arrangements.

6.4.1 Stakeholder's views

Grid Australia, in its submission to the discussion paper, was concerned to ensure that any rule change made would not prejudice future reform arising out of the Transmission Frameworks Review, noting that: “introducing a relatively simple arrangement now would not necessarily interfere with further changes required as a result of the TFR. However, more complex far reaching options may create issues for future subsequent changes."[54]

6.4.2 Commission analysis

The modified load export charge and NEM wide cost reflective network pricing are consistent with existing intra-regional transmission pricing arrangements. They are robust should they remain in place for an extended period of time but would allow for more significant reforms to transmission pricing more generally should that be considered necessary. The load export charge might be considered to entrench existing inconsistency in cost reflective network pricing methods between regions and thus would represent a move to more unstable regulatory arrangements.

The cost sharing proposal by the group of generators would represent a method of determining inter-regional transmission charge which is fundamentally different to current network pricing approaches. It would represent a substantial change from existing arrangements. From this perspective at least, it would add to regulatory instability.

6.4.3 Conclusions regulatory stability

The modified load export charge is the most incremental improvement on existing arrangements within the scope set by the SCER rule change request. It is therefore also the most consistent with regulatory stability.

6.5 Administrative efficiency

The Commission considers it important that administrative costs, especially implementation costs, are low to ensure that the rule change delivers net benefits in accordance with the National Electricity Objective.

6.5.1 Stakeholder's views

For cost reflective network pricing options, stakeholders generally expected administrative costs to be proportionate to the difference between inter-regional methods and existing intra-regional methods. In its response to the discussion paper Grid Australia noted that "new options appear to be administratively complex to implement, as they represent a shift away from the existing method transmission network service providers use for their intra-regional charging."[55] Similarly, OEPC anticipated that "administrative costs will be higher for those jurisdictions that apply a different method in calculating intra-regional charges to that used for calculating the nationally consistent inter-regional."[56]

Grid Australia predicted that administrative costs could be minimised by being pragmatic about requiring uniformity only to address "major" differences in intra-regional methods.

54 GridAustralia, submission to the discussion paper, 23 September 2011, p 8

55 Grid Australia, response to the AEMC's discussion paper, 23 September 2011,p 8

56 OEPC, submission to discussion paper, 23 September 2012, p 4

Nevertheless, it can be expected to be administratively onerous for those transmission businesses using standard cost reflective network pricing intra-regionally to apply a modified cost reflective network pricing method to calculating an inter-regional transmission charge. This is because collecting and applying asset utilisation data is complex and time consuming. For transmission businesses that have never used modified cost reflective network pricing, there will also be the time and costs associated with the adjustment to the new process.

In relation to cost sharing, the group of generators acknowledged a risk that “desirable projects may be delayed by a stalemate over cost allocation”[57] and proposed that cost allocation should be verified by an “independent authority” to mitigate this risk, acknowledging that this might require some “additional administrative effort.”[58]

AEMO noted that agreement between transmission businesses to share transmission costs across regional boundaries has “been applied only once in the NEM.”[59]

Grid Australia considered that implementation of an NEM-wide cost reflective network pricing would require “a consistent national valuation and cost allocation model” and existing “inconsistencies between replacement cost models” therefore presented a” fundamental obstacle.”[60]

6.5.2 Commission's analysis

Implementation costs

Implementation costs of the load export charge and modified load export charge are expected to be modest. This is because these methods require only minor changes to existing intra-regional pricing processes in:

- including connection points within the cost reflective network pricing cost allocation process for the purposes of calculating load export charge or modified load export charge; and
- for modified load export charge, the need to apply a standard form of cost reflective network pricing for the purposes of calculating the charge.

The variant of cost reflective network pricing to be used in the modified load export charge minimises these implementation costs.

The NEM-wide cost reflective network pricing option requires that the pricing institution establishes a cost reflective network pricing process that covers the entire NEM. In principle, this should not be too complex, since NEM-wide data exists in a form that can be fed into TPRICE.[61] The modelling consultant engaged by the Commission to estimate consumer impacts (see section 6.6) found that establishing an NEM-wide cost reflective network pricing method was not as straightforward as

57 Group of generators, submission to discussion paper, 23 September 2011, p4

58 Group of generators, submission to discussion paper, 23 September 2011, p8

59 AEMO, submission to discussion paper, 4 October 2011, p 2

60 Grid Australia, submission to the discussion paper, 23 September 2011, p 14

61 TPRICE is the computer program used by TNSPs in calculating their prices

expected, and a number of issues arose that would require resolution in an NEM-wide cost reflective network pricing implementation. These included:

- data errors and inconsistencies within a region leading to anomalous interconnector flows. These were corrected in the modelling by introducing fictitious generators on region boundaries; and
- outcomes were sensitive to assumptions on generator source impedances. In the cost reflective network pricing method this affects how generation is matched to load for the purposes of deeming asset usage.

These issues would need to be resolved in any implementation of a NEM-wide cost reflective network pricing.

The Commission agrees with Grid Australia that a NEM-wide cost reflective network pricing requires consistent asset cost allocation between regions otherwise inter-regional transmission charge outcomes could reflect these inconsistencies rather than market and cost fundamentals. This is a similar concern to that relating to load inconsistencies in applying the load export charge. Although establishing consistent cost allocation may be a worthwhile objective in its own right, it may be very costly to achieve.

Further, the implementation of a NEM-wide cost reflective network pricing requires the identification of a party to undertake the modelling and make decisions where conflicting data arises. Currently, there is no organisation with both the requisite skill base to undertake the necessary modelling and sufficient independence from the results of the modelling. The implementation costs of the NEM-wide cost reflective network pricing approach can therefore be expected to be substantially greater than the other cost reflective network pricing options.

Implementation costs of a cost-sharing approach are also likely to be greater. Mechanisms or processes would need to be designed and implemented to:

- identify any new “inter-regional assets” to which a cost-sharing approach would apply; and
- allocate the costs of these assets, using a formulaic or “beneficiary pays” approach.

Although existing RIT-T methods calculate expected benefits, these are not easily attributable to particular regions. Developing an attribution method is likely to be difficult and contentious.

Operational costs

The cost-sharing and cost reflective network pricing options have fundamentally different operational costs. Cost-sharing only takes place when new interconnector assets are developed. This is likely to occur only rarely. However, precisely because the cost-sharing process is not routine, the costs of determining the inter-regional transmission charge when it is required are likely to be high. Furthermore, the very fact that transmission network service providers only incur these costs when an inter-regional asset is developed may discourage them from undertaking such an investment: which is precisely the opposite effect to what the rule change request seeks to achieve.

Cost reflective network pricing, on the other hand, would be undertaken annually, irrespective of transmission investment. With annual repetition, any administrative difficulties would be expected to be quickly resolved and so ongoing annual costs will be low.

The modified load export charge and NEM-wide cost reflective network pricing methods are intrinsically more administratively onerous than the load export charge method, because they involve a second, inter-regional run of the cost reflective network pricing method. However, for the modified load export charge, the administrative cost of this inter-regional run is not expected to be onerous, since it will use essentially the same data as the intra-regional run, with a few settings changes on the TPRICE program to reflect (for some regions) the difference in the method used.

For NEM-wide cost reflective network pricing, the costs may be significantly higher. On the other hand, the operation is only carried out once, by a single institution. In the other cost reflective network pricing methods, each transmission network service provider carries out the inter-regional transmission charge calculation at the same time.

6.5.3 Conclusions on administrative efficiency

Administrative costs for the load export charge and modified load export charge are anticipated to be low.

While the operational cost of NEM-cost reflective pricing might be similar to or even lower than the other cost reflective network pricing options, the implementation issues are so significant in the current NEM framework that overcoming them may be greater than benefits to be derived from the introduction of an inter-regional transmission charge.

Cost-sharing is likely to have high implementation and operational costs, although operational costs are only occurred when a new inter-regional asset is developed, which may be relatively infrequent. On the other hand, the prospect of incurring these costs might actually deter efficient inter-regional investment.

6.6 Impact on consumers

Changes to arrangements should be proportionate to the issues being addressed and any new charges introduced should to the extent feasible, be predictable, stable and measured in its impact on consumers.

6.6.1 Stakeholder's views

The AER noted in its submission to the discussion paper that changes to transmission network service provider pricing methodologies could cause price shocks for consumers.[62]

Grid Australia, in a submission to the draft determination pointed out that "a change in the methodology of allocating transmission costs nationally raises the possibility of a quantum change in a region’s TUOS charges. The value of these measures in terms of

62 AER submission to the discussion paper ,p 2

their ability to drive more efficient outcomes needs to be questioned if they exhibit a high level of volatility from year to year.[63]

The MEU was concerned that variability in costs is a major concern in regions that have a large degree of weather risk. They also considered that prices which show significant variability year on year will reduce the locational signals to generators and consumers.[64]

In its submission to the discussion paper, the OEPC considered some form of smoothing mechanism needed to be introduced such that charges do not vary significantly and unpredictably from year to year.[65]

The group of generators noted its proposal for cost sharing would confer a high degree of stability as “the cost impact of inter-regional charges, under our proposal, would be known with great precision well in advance, subject only to the possibility of cost reductions in the event of re-allocation of relevant assets to other purposes."[66]

6.6.2 Commission's analysis

The Commission agrees that the cost sharing proposal by the group of generators would likely lead to the highest predictability and stability in charges, due to such charges being determined and fixed ex ante.

For the other cost reflective network pricing inter-regional transmission charge options, the Commission was keen to assess the potential quantum of impacts on consumers. A consultant ROLIB Pty Ltd was engaged to estimate the inter-regional transmission charge (ROLIB Pty Ltd report). The ROLIB Pty Ltd report is available on the Commission’s website. The cost to consumers under a cost sharing method would be directly related to the allocation method selected.

Tables 6.2 to 6.6 set out the modelling results below; they present estimated average inter-regional transmission charges for the period 2009-12 (had inter-regional transmission charge been implemented for those years) using the three cost reflective network pricing-based options:

- Load export charge: contained in the rule change request.
- Modified load export charge: the preferred method, described in section 4.3.
- NEM-wide cost reflective network pricing method.

Because of the lack of pricing efficiency that would result from the inclusion of postage stamp components in the pricing calculation, only locational inter-regional transmission charge charges are modelled.

63 Grid Australia submission to the draft rule determination, 25 February 2011, p 5

64 MEU, submission to the discussion paper, 23 September 2011, p 4

65 OEPC, submission to the discussion paper, 23 September 2011, p 2

66 Group of generators submission to discussion paper, 23 September 2011, p 9

The impacts of the load export charge are derived by applying, as accurately as the scope of the modelling allows, the cost reflective network pricing methodology that each transmission network service provider applies currently in its own region.[67]

This includes the following depending on the region in which it is applied:

- Measure of peak utilisation - In Victoria, the regional system peak approach (averaged over 10 days) is applied and in other regions the 365 element peak method is applied.
- Cost reflective network pricing method - in all regions the standard (as opposed to modified version) cost reflective network pricing method is applied.[68]
- Assets to be allocated - in all regions, the costs of all assets are allocated.

Modelling results

Table 6.2 Estimated load export charge ($M annual average for period 2009-2012)

		Region paying inter-regional transmission charge					
		Tas	SA	Vic	NSW	QLD	Gross Received ($M)
Region Receiving inter-regional transmission charge	Tas		0	5	0	0	5
	SA	0		20	0	0	20
	Vic	0	22		0	0	22
	NSW	0	0	25		8	33
	QLD	0	0	0	17		17
Gross Paid ($M)		0	0	22	50	18	98
Net Paid		-5	2	28	-15	-9	

Table 6.3 Estimated modified load export charge ($M annual average for period 2009-2012)

	Region paying inter-regional transmission charge					
	Tas	SA	Vic	NSW	QLD	Gross Received ($M)

67 Variants to the cost reflective network pricing methodology are explained in more detail in Chapter 4

68 Although SA and Tasmania use modified cost reflective network pricing, the estimated outcomes for modified cost reflective network pricing are not materially different to the standard approach.

		Region paying inter-regional transmission charge					
Region Receiving inter-regional transmission charge	Tas		0	5	0	0	5
	SA	0		20	0	0	20
	Vic	1	33		32	0	65
	NSW	0	0	25		8	33
	QLD	0	0	0	17		17
Gross Paid ($M)		1	33	50	49	8	140
Net Paid		-5	13	-16	17	-9	

Table 6.4 Estimated NEM-wide cost reflective network pricing charge ($M annual average for period 2009-2012)

		Region paying inter-regional transmission charge					
		Tas	SA	Vic	NSW	QLD	Gross Received ($M)
Region Receiving inter-regional transmission charge ($M)	Tas		1	8	0	0	9
	SA	1		24	4	0	29
	Vic	1	35		38	12	86
	NSW	1	3	28		18	50
	QLD	0	0	1	24		25
Gross Paid ($M)		3	39	60	66	31	
Net Paid ($M)		-6	10	-26	16	6	

Table 6.5 Net impact of charge as a proportion of location TUOS services

	Tas	SA	Vic	NSW	QLD
Load export charge	-9.1%	1.7%	11.6%	-4.9%	-4.0%
modified load export charge	-7.9%	12.0%	-6.5%	5.3%	-4.0%
NEM-wide cost reflective network	-10.5%	9.4%	-10.6%	5.0%	2.4%

	Tas	SA	Vic	NSW	QLD
pricing					

Table 6.6 Standard deviations of Inter-regional charges (for period 2009-2012)

	Tas	SA	Vic	NSW	QLD
Load export charge	2.0%	3.3%	1.2%	0.8%	0.2%
modified load export charge	1.8%	1.2%	1.1%	0.3%	0.2%
NEM-wide cost reflective network pricing	3.4%	3.1%	1.4%	2.0%	2.3%

Table 6.5 shows the impact of the different inter-regional charging approaches as a proportion of the overall locational component of prescribed TUOS services, with proportions ranging from -9.5 per cent in Queensland (being a net receiver of the charge), to 12 per cent in South Australia (a net payer), depending on the approach adopted.

Given the locational component of TUOS services itself is 50 per cent of the total transmission costs for consumers; this indicates that none of the options modelled will make up a large component of overall transmission charges.

The tables also show the level of variation (standard deviations) of inter-regional charges under the different approaches modelled. However it should be noted that the data range is relatively small.

The outcomes are broadly similar under modified load export charge and NEM-wide cost reflective network pricing: Queensland has the biggest difference with 6 per cent. However, outcomes under the load export charge are markedly different, with Victoria going from paying 12 per cent under load export charge to receiving 11 per cent under NEM-wide cost reflective network pricing. That difference arises because of the different cost reflective network pricing method used in Victoria under the load export charging option.

As shown in table 6.6, the modified load export charge gives the most stable outcomes, with variations per annum of around 2 per cent or less. The load export charge and NEM-wide cost reflective network pricing give variations of more than 3 per cent in some cases.

Under normal operation, average intra-regional TUOS prices vary in line with average revenue (capped revenue divided by demand) which, taking into account variations in Settlement Residue Auction (SRA) proceeds, may cause variations of up to 10 per cent per year. Around this average, variations of up to 2 per cent are permitted. Thus, a one-off impact of 12 per cent, followed by maximum year-on-year variations of 4 per cent say (2 standard deviations) is broadly in line with existing TUOS variations. Therefore, the Commission does not consider it necessary to phase in the new charging regime over several years nor to introduce a smoothing mechanism across years.

6.6.3 Conclusions on consumer impacts

Consumer impacts appear to be proportionate to the objective of improved pricing efficiency. The price change that would likely occur on the introduction of an inter-regional transmission charge are similar in magnitude to typical annual price variations that consumers face currently, so no phasing-in of the inter-regional transmission charge price is required in order to reduce volatility.

NEM-wide cost reflective network pricing prices appear to vary rather more from year to year than the other cost reflective network pricing options. It is not clear whether they are better at tracking changes in the fundamentals or volatility is an inherent feature of the approach.

The Commission concludes that all the cost reflective network pricing options are satisfactory in their impact on consumers, with the modified load export charge having the lowest relative impact.

6.7 Conclusions on inter-regional transmission charge method

After consideration of the relevant issues discussed above, the Commission is of the view that the modified load export charge, on balance, best meets the assessment criteria, for reasons that:

- it is calculated and applied in a more consistent way compared to the original load export charge as set out in the Ministerial Council on energy rule change request;
- it is more consistent with allocating costs in line with beneficiaries over time relative to the proposal for cost sharing put forward by the group of generators;
- provides for greater administrative simplicity compared to NEM wide cost reflective pricing approach and group of generators proposal;
- it is at least as good as the NEM-wide cost reflective pricing approach with respect to transparency and better than the other options; and
- is strongest of all options with respect to promoting regulatory stability and ensuring proportionate consumer impacts.

The Commission considers therefore that on balance the modified load export charge best meets the National Electricity Objective.

7 Implementation of the final rule

The final rule implements the modified load export charge. To aid transparency and promote certainty for consumers, the Commission has included the methodology for calculating the modified load export charge in the rules. The Commission considers elevation of such transparency into the rules is important in the context of transmission businesses levying such a charge on one another.

Table 7.1 sets out the impact of modified load export charge will have on the allocation methods and pricing methods of transmission businesses, in particular indicating that the pricing methods will remain unaffected.

Table 7.1 Impact of inter-regional transmission charge on cost allocation

Cost component	Allocation method	Pricing method	Impact of inter-regional transmission charge based on modified load export charge
Prescribed common services	Allocated to connection points on a postage stamp basis	Postage stamp (eg $/MW/day or $/MWh)	**Allocation** No change to these arrangements **Pricing** No change to these arrangements
Prescribed TUOS services	Split between locational and non-locational based on 50:50 split or alternative allocation based on a reasonable estimate of future network utilisation and future transmission investment		**Allocation** No change to these arrangements
Locational	Allocated to connection points using a cost reflective network pricing method (less settlement residue auction proceeds)	Three methods available. All are expressed in $/MW/day.	**Allocation** Inter-regional transmission charges added to, or subtracted from, locational cost prior to using cost reflective network pricing method to allocate to connection points **Pricing** No change to these arrangements
Non-location al	Allocated to connection points on a postage stamp basis (less other adjustments, eg over/under recovery)	Postage stamp (eg $/MW/day or $/MWh)	**Allocation** No change to these arrangements **Pricing** No change to these arrangements

7.1 Description of the operation of the rule

Calculation of the modified load export charge

Each coordinating network service provider is required to calculate the modified load export charge as follows:

- the coordinating network service provider must allocate 50 per cent of its annual service revenue requirement (ASRR) for prescribed TUOS services on a locational basis between all connection points within its region, including connection points between that region and other regions. This allocation must be made using the prescribed cost reflective network pricing methodology; and
- the prescribed methodology for calculating the modified load export charge is a nationally consistent methodology for attributing the costs of transmission system assets based on the standard cost reflective network pricing methodology but with certain prescribed requirements as follows:
  - all transmission system assets must be included for the attribution of network costs;
  - operating conditions in all half hour periods of the prior financial year must be taken into account; and
  - peak usage of transmission system elements must be used.

The above methodology will result in an allocation of costs to connection points between regions. These costs will constitute the modified load export charge.

Publication of the modified load export charge

A transmission network service provider who is a coordinating network service provider will be required to publish details on the modified load export charge by 15 March each year. The rules provide that all transmission network service providers are required to publish their prices by 15 May each year.

Charging arrangements for coordinating network service providers

A coordinating network service provider for region A will invoice the coordinating network service provider of the interconnected region B for any modified load export charge it estimates to be payable in respect of region B in the coming regulatory year.

The coordinating network service provider for region B will allocate the net modified load export charge payable or receivable in respect of region B to the transmission network service providers located in region B.

Charging arrangements for transmission network service providers

Each modified load export charge's balance allocated to a transmission network service provider by its coordinating network service provider must be allocated for recovery (or pass through) by that transmission network service provider to its consumers by way of an adjustment to that transmission network service provider's locational component of prescribed TUOS services.

Allocation of costs and determination of pricing for connection points within its region will otherwise be calculated by the transmission network service provider in accordance with its current practice under the NER.

True up

In subsequent years, each coordinating network service provider will calculate a true up amount based on the actual network utilisation information available to it using the same modified load export charge methodology as described above.

The coordinating network service provider or region A will invoice the coordinating network service provider of any relevant interconnected region for any true up amount payable in respect of that region. The coordinating network service provider for region B then allocates that true up amount in respect of region B to the transmission network service provider located in region B.

Each transmission network service provider then includes that true up amount as an adjustment to the modified load export charge amount to be recovered as part of its allocation of the locational component of prescribed TUOS services as described above.

Pricing methodology

The AER will be required to amend the pricing methodology guidelines in accordance with the introduction of modified load export charge in the NER.

Transmission network service providers and coordinating network service providers will be required to amend their pricing methodologies to incorporate the calculation and allocation of the modified load export charge in accordance with the requirements of the rules.

Settlement residue auction proceeds

Under the current arrangements, SRA proceeds are redistributed by the transmission network service provider to consumers in the importing region on a locational basis. This redistribution of these benefits is consistent with the purpose for having inter-regional transmission capacity; which is to provide access to lower cost energy in the exporting region. Further, distributing such benefits on a locational basis allocates those benefits on the basis of proportionate utilisation of transmission capacity. The Commission considers that the allocation of some of the benefits of inter-regional capacity in this manner is appropriate and consistent with allocation of the costs of such capacity.

In the MCE rule change request, the MCE argued that settlement residues should be distributed on a postage stamp basis. For the reasons noted above however, the Commission has decided that the SRA proceeds should continue to be redistributed on a locational basis in accordance with the current provisions.

Including a modified load export charge in the locational charges

The final rule provides that the estimation and charging for modified load export charge is to be based upon the standard cost reflective network pricing methodology. This requires that recovery of the load export charge should be done on the basis of the 50/50 split used for is included in the 50 per cent of the aggregate services revenue requirement (ASRR)[69] which is allocated to prescribed locational TUOS services. While this is consistent with the approach adopted by most transmission network service providers, it is not the same as the split between location and non-locational revenue used by some transmission network service providers, for example ElectraNet.

The Commission specified the 50 per cent split for interregional transmission charging in order to standardise the approach for the estimation and recovery of modified load export charges. The alternative is to allow transmission network service providers to identify their allocation of the ASRR in the same manner as they do for intraregional transmission charges. However, this could result in charges that are higher or lower for some regions purely based on the methodology for determining locational charges.

7.2 Public information

The final rule requires the following information to be published by the AER;

- its amended pricing methodology guidelines to take into account the modified load export arrangements by 30 September 2014; and the transmission network service providers' proposed amended pricing methodologies, which take into account the amended AER pricing methodology guidelines for incorporating the new inter-regional charging arrangements.

Also, the final rule requires a transmission network service provider, where the transmission network service provider is the coordination network service provider, to publish the inter-regional transmission charge amount by 15 March each year.

7.3 Information to be contained on coordinating network service provider to coordinating network service provider inter-regional transmission charge bill

The Commission has specified the minimum information to be included on the bill from one coordination network service provider to another coordination network service provider (in addition to the requirement for the transmission network service provider who is a coordinating network service provider to publish the modified load export amount for the next financial year).

The final rule requires that a modified load export charge bill must include the following information:

- reasonable details of the calculation of the modified load export charges; and

69 See Appendix B for a detailed explanation for how revenues are allocated to prescribed transmission services

- reasonable details of the calculation made to the modified load export charge (ie for the true up between estimated modified load export charge and modified load export charge based on actual system use).

7.4 Adjustment of the prescribed TUOS services – locational component for the modified load export charge

The final rule prescribes the manner and sequence for the modified load export charge to be adjusted for the prescribed TUOS services – locational component, including that it be excluded from the 2 per cent price annual variation as transmission network service providers prices for prescribed TUOS services – locational component.

7.5 Sequence for calculating inter-regional transmission charges

The final rule is based on the sequence for the calculation of inter-regional transmission charge as outlined in 7.1. This now includes recovery or pass through of the modified load export charge payable or receivable as annual adjustments to the locational component of the ASRR for prescribed TUOS services. This contrasts with incorporating the modified load export charge recovery or pass through across the ASRR's for all components of prescribed TUOS services and common transmission services as was outlined in the original draft determination.

The modified load export charge introduces a need for coordinating network service providers to communicate the results of their calculation of inter-regional transmission charge to neighbouring regions to enable them to calculate their intra-regional transmission charges. The transmission network service provider is required to publish their prices for the next regulatory period no later than 15 May.

In order to give the transmission network service provider sufficient time to determine the impact of the inter-regional transmission charge on their intra-regional charges the Commission has required that the coordinating network service provider submits the results of its calculation of inter-regional transmission charges to the neighbouring coordinating network service provider no later than 15 March.

The Commission is of the view that this gives the neighbouring coordinating network service provider and transmission network service provider sufficient time to include the charge in the locational component of their intra-regional charges.

7.6 Commencement

The final rule includes a commence date of inter-regional transmission charge of 1 July 2015. This would require the first publication of inter-regional transmission charge under the modified load export charge by 15 March 2015. It is the AEMC’s view that this provides sufficient time for the AER to revise its guideline on transmission pricing and for the transmission network service providers to update, and publish, an updated method for the calculation of both intra and inter-regional transmission charges.

7.7 Savings and transitional provisions

The Commission has incorporated a number of transitional provisions in the final rule. The AER is required to amend its pricing methodology guideline by 30 September 2014, with transmission network service providers to amend their price methodologies no later than 27 February 2015.

A Summary of issues raised in submissions

A.1 Submissions to consultation paper

Stakeholder	Issue	AEMC response
General views and issues on the Rule Change Request		
Gallaugher & Associates (p. 1)	In broad terms supports the concept of inter-regional network charges proposed but considers there are many serious flaws with the current regulatory and economic framework for the provision of transmission services in the NEM.	The Commission notes that the specific points raised in Gallaugher & Associates submission, as well as other submissions, on the design of the load export charge are discussed in this determination.
Hydro Tasmania (p. 1)	Broadly supports the proposal to introduce inter-regional transmission charging. Has reservation with the Commission's inter-regional transmission charging proposal on the prediction of future network flows as a basis for assigning costs shares.	As discussed in chapter 5 of this determination, the Commission considers that the current approach to allocating costs can accommodate load export charges. Specific discussion relating to issues in Tasmania are discussed in section 7.4.2.
Integral Energy (p. 1)	Supports the principle that consumers who import power from another region should contribute towards the transmission costs thereby incurred in the exporting region and considers that the load export charge approach set out in the Consultation Paper provides a suitable mechanism for doing so.	The Commission notes the comments made.
Grid Australia (p. 3)	Supports the implementation of a load export charge based on the locational component of prescribed transmission prices to commence from 1 July 2012 at the earliest.	As discussed in sections 5.4.3 and 6.4.3, the Commission considers that a 1 July 2012 commencement date for the load export charge would be more appropriate.

Stakeholder	Issue	AEMC response
The Major Energy Users Inc (MEU) (p. 3)	While the Rule change request conceptually seeks to impose a higher degree of cost reflectivity, it has the potential to create more problems than it solves e.g. some beneficiaries will receive a greater benefit at the expense of other consumers. Also considers that the Rule change proposal lacks quantification and undermines key principles underpinning the NEM [in ways as discussed in other sections of the MEU's submission as outlined below].	As discussed in section 2.6, the load export charge may result in a one-off redistribution of charges among consumers in different regions. However, this redistribution would result from the improvement in cost-reflectivity, which would benefit all consumers in the long term. The modelling outcomes has shown the potential cross-subsidies that currently exist. The Commission does not consider the Rule change undermines the underlying principles of the NEM (as discussed in response to the MEU's issues below).
MEU (p. 7)	Although the MEU supports, in principle, allocating the costs of interconnectors to the beneficiaries of the interconnectors, it raises a number of issues and concerns on the proposed arrangements. pp. 4-5. In addressing these inconsistencies in the proposed arrangements, the MEU is concerned that the complexity that then arise will make the implementation too complex to deliver a sensible and commercial outcome for consumers.	In making this determination, the Commission has clarified the principles of the load export charge, where any export load would be treated in a similar manner to existing consumer load. In doing so, the Commission considers that the load export charge provides a proportionate solution to the requirement of inter-regional transmission charging arrangements and that its implementation would not be complex.
MEU (p. 7)	The Rule change proposal posits that consumers will accrue significant commercial benefit by the implementation of the change and therefore it should cover the costs that generators and transmission network service providers will incur as a result of the Rule change. But considers there is no attempt to quantify either the costs or benefits of the proposal, let alone the materiality of the issue.	The Commission considers that the Rule change proposal recognises the potential benefits of introducing inter-regional transmission charging arrangements. The materiality of the potential impact of an load export charge is discussed further in section 7.4.
MEU (pp. 8-9)	Considers that the Rule change request had its origins from a request of the MCE for the AEMC to	The Commission notes that the objective of the Climate Change Review was to consider how the

Stakeholder	Issue	AEMC response
	conduct the Climate Change Review and considers that "effectively the AEMC sees that its recommendations [from the Climate Change Review] will assist the implementation of the expanded RET and CPRS policies, irrespective of the quantum of costs involved so long as the market outcomes (which will reflect the interventions) are seen to be 'efficient' and 'reliable'".	current energy market frameworks would respond to the expanded expanded RET and the CPRS and how any potential impacts of these policies on the market may be managed. The Commission did not consider how any of these policies should be implemented. In addition, the Commission notes that inter-regional transmission charging has been an issue that the market has considered and assessed for some time, including consideration by the National Electricity Code Administrator in its transmission and distribution revenue review completed in 1999. The Commission is now assessing the proposed load export charge through this Rule change process to consider whether the proposed arrangements would be in the long term interest of consumers.
MEU (p. 12)	In regards to cost-reflectivity considerations, raises the issue of the cost of power compared with the cost of transmission. Notes that the reasons for a region to be a normally importing region are many but the main reason is that the prices of generation in an importing region are higher than those in a normally exporting region. Just because there is a price differential does not mean that this differential is more than the additional costs of providing transmission.	The Commission notes the issue raised however the cost of transmission is typically a small proportion of the total costs for electricity that consumers face. Additional discussion is outlined in section 7.4.
MEU (p. 13)	Notes that if an importing region is expected to pay for transmission costs within an exporting region, from a consumer viewpoint, this makes generation from an exporting region a higher cost - effectively the cost to consumers in the importing region for the imported generation becomes the dispatch price for	The Commission notes that the load export charge is intended to improve the cost-reflectivity of transmission assets. In terms of whether the transmission investments themselves are efficient, the existing framework which provides for the role of the National Transmission Planner and the

Stakeholder	Issue	AEMC response
	the generation plus the load export charge. The proposal for allocating transmission services from an exporting region however implies that a generator outside a region will still be dispatched on the current basis. This raises the question - is the proposal really economically efficient and does it maintain competitive neutrality?	Regulatory Investment Test for Transmission go towards ensuring efficient transmission investments are made.
MEU (p. 14)	Considers that the Rule change proposal does not assess whether consumers will pay more for their delivered power under the proposed change than necessary and whether the proposal might reduce competitive neutrality between generators and regions.	The load export charge would relate to the regulated revenues of transmission network service providers and interconnectors. As the purpose of the revenue regulation process is to ensure that only efficient costs would be recovered, the Commission considers that the mechanisms in place ensures that consumers would not pay more than necessary. In addition, as the load export charge would apply to all transmission network service providers, and revenues are regulated, there would not be any impact on competitive neutrality.
MEU (p. 18)	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 simplicity of the current arrangements.	The Commission notes that as the pattern of interconnector flows responds to changes in the underlying market requirements, introducing an inter-regional transmission charging mechanism is an important step in ensuring that prices are cost-reflective.
National Generators Forum (NGF) (p. 1)	On balance, supports the proposed improvements to the transmission charging arrangements. However, have a concern on the potential difficulty to develop and set the load export charge with a degree of certainty. Energy movement from one region's transmission network to an neighbouring region's network is likely to be volatile. We expect	The provisions in place provide that charges to be applied to consumers cannot vary by more than 2 per cent per annum compared with the load weighted average price for the locational component of transmission charges. The Commission considers that this provides a degree of certainty. In addition, to the extent that the load

Stakeholder	Issue	AEMC response
	the energy forecasts used to work out a load export charge to be similarly variable. This could create problems around certainty. Do note, however, that forecasting energy flows for consumer loads at existing connection points on the transmission system are relatively stable.	export charge improves cost-reflectivity, any volatility in costs would be reflected in prices. In addition, as noted above, the transmission charges component of a consumer's bill is relatively small.
NGF (p. 2)	Considers the proposed methodology of implementing a load export charge is consistent with the current methodology in the AER's electricity transmission network service providers pricing methodology guidelines.	The comments are noted.
AEMO (p. 1)	Supports in principle the introduction of inter-regional transmission charges. Considers the proposal is consistent with the establishment of the role of the national transmission planner within AEMO and recognition of the need to coordinate the development of the grid on a national basis. Considers it would be incongruous to plan and develop the grid on a national basis without recognising this in transmission pricing.	The comments are noted.
AEMO (p. 1)	In undertaking this Rule change notes that there is the need to recognise that transmission pricing is complex and that detailed procedures are not specified in the Rules and the implementation in respect to a number of details are likely to vary from one region to the other and that the overall outcomes of the methodology can be very sensitive to a range of decisions. The final process to be determined should seek to deliver both a workable and consistent process and meet the MCE's objectives in introducing inter-regional transmission	The comments are noted. The Commission also acknowledges the work that transmission network service providers and AEMO have completed in providing modelling for this Rule change request, which has assisted with the analysis and understanding of the proposed arrangements.

Stakeholder	Issue	AEMC response
	charging.	
Energy Australia (pp. 1-2)	Considers that quantitative analysis of the potential impact of the proposed change on stakeholders, including consumers, should be completed and subject to further consultation.	The Commission notes the issue and the results from the modelling undertaken by transmission network service providers, including AEMO in its capacity as a transmission network service provider in Victoria, are discussed in section 7.4.
Composition and definition of the load export charge		
Integral Energy (p. 1)	Supports the extension of the current transmission pricing principles to determining the load export charge, including both locational and non-locational components for the relevant TUOS charges.	The comments are noted.
Integral Energy (p. 2)	As a general principle, would like to see greater stability and transparency in transmission pricing. In the current context, supports the proposed Rule setting out notification processes and requiring a level of information disclosure from the coordinating network service provider that ensures the impact on distribution and retail tariff notification processes can be managed as effectively as possible.	The comments are noted. transmission network service providers would be required to provide estimates to each other and, where possible, to DNSPs. The AER would also be required to amend its pricing methodology guidelines and transmission network service providers would be required to amend their pricing methodologies.
Grid Australia (pp. 3, 6-7)	The inclusion of the postage stamped components of prescribed transmission prices is likely to result in importing regions making a contribution significantly beyond the long run marginal costs of existing and new transmission assets which support inter-regional flows. Considers the inclusion of these components departs from the principles of the current pricing regime and would not be consistent	Discussion is outlined in chapter 5.

Stakeholder	Issue	AEMC response
	with the NEO.	
Grid Australia (p. 6)	To include postage stamped components would be to impose costs on consumers of an neighbouring region that bear no relation to their proportionate use of the neighbouring region's transmission system assets. Such a view is also consistent with the ACCC position where it was expressed that rather than to be used as a tool for signalling, the non-locational component is to serve as a recovery mechanism that will cause the least distortion possible.	Discussion is outlined in chapter 5.
Grid Australia (p. 11)	The volatility of annual energy flows across interconnectors would lead to considerable volatility in the load export charge on a year to year basis. The effect of this volatility on consumers (in both the importing and exporting regions) would depend on the relative materiality of the charge. Is concerned that the introduction of the postage stamp components to the load export charge will materially increase the impact of the load export charge on consumers and may lead to even greater volatility from year to year.	The Commission acknowledges that it may be difficult to predict how interconnector flows will vary in the future. However, it is noted that any changes in the overall interconnector flow profiles would happen over time. As the load export charge is intended to increase the cost-reflectivity of prices, if there is volatility in the underlying costs then this would be reflected in the charges - although any variations in costs would also be impacted by the redistribution of settlement residue auction proceeds. As noted above, the load export charge and transmission charges in generation are not expected to be a significant portion of a consumer's bill.
NGF (p. 2)	A load export charge that includes both a locational and non-locational component of prescribed TUOS implemented in a way that minimises price volatility is suitable. We expect that the AEMC will engage with transmission network service providers to	Discussion is outlined above and in chapter 5.

Stakeholder	Issue	AEMC response
	facilitate this outcome.	
Hydro Tasmania (p. 2)	In the case of Victoria/Tasmania inter-regional transfer, forecasting of network flows is particularly difficult, depending as they do on hydrological inflows in Tasmania, which can vary ±30%. Would ask the Commission consider how the process for determining the inter-regional transmission charges could cater for potentially large swings from year to year, in inter-regional transfer payments between Victoria and Tasmania, without resulting in unmanageable variations in Consumer costs.	Discussion is outlined above and in section 7.4.2.
Hydro Tasmania (p. 2	In the case of Victoria/Tasmania inter-regional transfer, forecasting of network flows is particularly difficult, depending as they do on hydrological inflows in Tasmania, which can vary ±30%. Would ask the Commission consider how the process for determining the inter-regional transmission charges could cater for potentially large swings from year to year, in inter-regional transfer payments between Victoria and T)asmania, without resulting in unmanageable variations in Consumer costs.	Discussion is outlined above and in section 7.4.2.
Grid Australia (p. 4)	To define the export load the appropriate quantity to use would be a prescribed capacity of the notional interconnector, which defines the capacity in place of a "contracted demand".	The Commission notes the suggestion proposed. As discussed in section 5.4.3, the Commission considers that the prescribed capacity would be required.
Grid Australia (p. 5)	The definition of notional interconnector capacity will significantly impact the magnitude of the TUOS non-locational and common service component charges. Considers that two options are readily available: (1) the capacity used by AEMO in the	As discussed in section 5.4.3, the Commission considers that the maximum directional flow on the notional interconnector would be an appropriate measure.

Stakeholder	Issue	AEMC response
	settlement residue auction process; and (2) the maximum directional flow in the notional interconnector in the previous year.	
Grid Australia (p. 8)	Notes that the pricing methodology mandates that the contract agreed maximum demand should only be used for charging if the consumer's connection agreement or other enforceable instrument governing the terms of connection stipulates a fixed maximum demand and penalties for exceeding that demand. Consideration should be given to the ability to satisfy this requirement under the proposed arrangements.	The Commission agrees that an appropriate definition would need to be introduced and considers that maximum flow on the notional interconnector in the last year may be used for this purpose.
Grid Australia (p. 6)	Although, in simplistic terms, consumers in importing regions use the shared network services in a similar way to consumers with the exporting region, it is not clear that consumers in the importing region would be readily able to associate their behaviour with the load export charge allocated to them and respond appropriately. This would depend, in part, on the relative materiality of the inter-regional charge.	The Commission notes that the load export charge mechanism would provide an important step in the pricing arrangements to accommodate likely future changes in interconnector flows. The modelling results are discussed in section 7.4.
MEU (pp. 13-14)	If the regional node in the importing region is located closer to the border than the regional node in the exporting region, then the costs of transmission to the border in the exporting region are much higher than the costs of transmission to the border of the importing region. Therefore there will be a disparity between the rate of the "load export charge" in one region compared to another. Despite this as power flows in both directions, it is assumed that the amount of power transferred is a net amount. This	As discussed in chapter 5, the locational component of the load export charge is calculated in a similar method to other loads. That is, the Rules require the cost-reflective network pricing (cost reflective network pricing) or the modified cost reflective network pricing methodology to be used to determine the proportionate use of the system. This methodology is not related to the location of the regional price node, which relates to the

Stakeholder	Issue	AEMC response
	means that the export from the net importing region has a lower value in terms of dispatch price plus load export charge than export from the net exporting region in terms of dispatch price plus load export charge.	determination of the spot price.
MEU (p. 16)	The proposal to introduce a load export charge, which would have a locational component, would mean that the locational element of TUOS in the importing region will become distorted by the addition of locational TUOS from the load export charge. As locational TUOS is calculated from the regional node, this approach will provide a penalty on consumers located close to the point of importation. Considers that neither the consultation paper or the Rule Change Request provided any reason for making this change, yet it will necessarily increase the costs incurred by consumers located close to an importation point.	As discussed above, the calculation of locational transmission charges is based on a consumer's proportionate use of the network assets. This is related to the location of the consumer on the network itself and not related to the location of the regional reference node. Additional discussion is outlined in section 5.4.3.
NGF (p. 1)	Supports a load export charge that reflects the costs of all assets which contribute to export flows to the neighbouring region as if an neighbouring region was a load on the region boundary.	The comments are noted.
Energy Australia (p. 3)	The major proportion of the non-locational costs is associated with assets servicing consumers within a region, rather than the small number of assets near the jurisdiction interface, whose locational cost would be allocated to consumers in another jurisdiction. Passing on these charges between regions, particularly in respect of sunk assets, would not contribute to "efficient investment in, and efficient operation and use of, electricity services".	Discussion is outlined in chapter 5.

Stakeholder	Issue	AEMC response
	Therefore, is not convinced that passing on the non-locational component of TUOS to another region contributes to pricing efficiency or to the market objective.	
Energy Australia (p. 3)	If the goal of the pricing arrangements is to promote efficient pricing signals, the AEMC could consider demonstrating to consumers that it has considered whether there should be a proportional allocation of cost to generators upstream of inter-regional interconnectors to provide efficient pricing.	The Commission notes the comments raised and notes that broader issues relating to the pricing and other regulatory provisions for the transmission network will be considered by the AEMC under the Transmission Frameworks Review.
Calculating and recovering the load export charge		
Integral Energy (p. 1)	Supports the adoption of consistent pricing methodologies across the NEM regions for the determination of load export charges, wherever feasible.	The Commission has maintained the principles of the existing framework for Chapter 6A of the Rules where the Rules set out the principles and additional implementation details would be set out in the AER guidelines. The Commission notes that the principles are aimed at promoting the adoption of consistency across regions and the AER is required to take this factor into consideration.
Grid Australia (p. 7)	By treating the point(s) of connection of a notional interconnector as a connection point the prices and charges can be calculated in a manner broadly consistent with the principles.	The comments are noted and additional discussion is outlined in section 5.4.3.
Grid Australia (p. 7)	A broader range of transitional provisions are required to allow coordinating network service providers to modify their approved pricing methodologies to the extent required to implement the changes arising from this Rule change. This	As discussed in section 6.4.3, the Commission has provided transitional provisions to allow transmission network service providers to amend their pricing methodologies.

Stakeholder	Issue	AEMC response
	would eliminate the double jeopardy inherent in the requirement to be compliant with both the Rules and the approved pricing methodology.	
Grid Australia (p. 7)	The most material difference between pricing methodologies is the implementation of the cost reflective network pricing in the Victoria region, which has been identified in the Rule change request.	The comments are noted.
Grid Australia (p. 7)	ElectraNet and Transend use approved implementation of the modified cost reflective network pricing methodology and considers this has no material impact on the proposed load export charge.	The comments are noted and additional discussion on the calculation of the load export charge is set out in chapter 5.
Grid Australia (p. 8)	The Rules should not be overly prescriptive in the calculation of the load export charge. Given the extremely complex nature of prescribed transmission pricing to introduce additional complexity in the Rules runs the real risk of unintended consequences arising. Grid Australia considers it would be more appropriate for the more detailed implementation issues to be dealt with in changes to transmission network service provider pricing methodologies, which would be subject to approval by the AER.	As discussed in chapter 5, the Commission has maintained the existing principles of Chapter 6A where the Rules set out the principles for revenue and pricing and additional implementation details are dealt with under the AER's guidelines and transmission network service providers' pricing methodologies. Some clarifications to address the requirements for the load export charge have been added.
Grid Australia (p. 9)	Notes that in order for the cost reflective network pricing process to operate the energy flows in both directions on the interconnector(s) must be modelled rather than setting the flows to zero when it is importing. This is consistent with the way interconnectors are currently modelled for	The Commission notes that the Rules would provide the principles of the load export charge. The AER's pricing methodology guidelines would provide additional guidance on any specific implementation issues and transmission network service providers' pricing methodologies would provide additional

Stakeholder	Issue	AEMC response
	prescribed pricing. Conversely, when calculating postage stamped prices and charges only the half hourly load (export) component of the energy flow should be considered as otherwise it is possible to have negative charges in some months. This does not appear consistent with the intent of the Rule change request.	clarification. This process would provide the opportunity to utilise the expertise of the AER and transmission network service providers.
Grid Australia (p. 9)	There is no available methodology which would allow the export charge from the adjacent region to be passed through to consumers using the cost reflective network pricing methodology which would not in turn influence the export charge to the neighbouring region. Accordingly an alternative methodology is required. The most administratively efficient mechanism would be to prorate the charge to consumers on the basis of their expected annual charge for that component of their prescribed transmission charges.	The Commission understands that transmission network service providers, through the modelling process, have been considering the requirements for performing the actual calculations for a load export charge and that it may be possible for an "iterative" approach to be taken to allow the required charges to be calculated.
MEU (pp. 9-10)	Noting the requirement under the clause 6A.23.4(e) of the Rules relating to the recovery of prices for prescribed TUOS services are to be recovered based on demand at times of greatest utilisation of the transmission network, questioned why AEMO, as the Victorian transmission network service provider, must be required to change its pricing policy from one which explicitly meets the pricing requirement set by the Rules, to one that does not meet the Rules in order to meet the inter-regional transmission charging arrangements.	The Commission notes that the amendment that is required of AEMO's pricing methodology relates to the calculation of the locational component of the prescribed TUOS service charge. This locational component must be calculated using either the cost reflective network pricing or the modified cost reflective network pricing methodology. Under the modelling processes of these methodologies (which are defined under Schedule S6A.3 of the Rules) there are different ways of achieving the pricing principles under the Rules of modelling the system to determine the times of greatest utilisation of the transmission network. The amendment to AEMO's methodology would be more consistent with the

Stakeholder	Issue	AEMC response
		introduction of the load export charge and would prevent any distortion being created in the price outcomes. Additional discussion is outlined in section 6.4.3.
MEU (pp. 9-10)	Noting the requirement under the clause 6A.23.4(e) of the Rules relating to the recovery of prices for prescribed TUOS services are to be recovered based on demand at times of greatest utilisation of the transmission network, questioned why AEMO, as the Victorian transmission network service provider, must be required to change its pricing policy from one which explicitly meets the pricing requirement set by the Rules, to one that does not meet the Rules in order to meet the inter-regional transmission charging arrangements.	The Commission notes that the amendment that is required of AEMO's pricing methodology relates to the calculation of the locational component of the prescribed TUOS service charge. This locational component must be calculated using either the cost reflective network pricing or the modified cost reflective network pricing methodology. Under the modelling processes of these methodologies (which are defined under Schedule S6A.3 of the Rules) there are different ways of achieving the pricing principles under the Rules of modelling the system to determine the times of greatest utilisation of the transmission network. The amendment to AEMO's methodology would be more consistent with the introduction of the load export charge and would prevent any distortion being created in the price outcomes. Additional discussion is outlined in section 6.4.3.
MEU (p. 10)	Concerned that the current proposal to allocate inter-regional costs in an exporting region to power importing regions does not take into account benefits of interconnection in terms of reliability. The mere presence of the ability to transfer power from one region to another when power shortages occur, has major value, even if the transfer occurs only occasionally. The MEU has a concern that the cost allocation approach used will overlook this benefit to a normally exporting region, and transfer these	The NTP and RIT-T ensures that efficient transmission investments are made giving consideration to a number of factors including the potential market benefits provided by each investment. Through these processes under the regulatory framework, appropriate consideration is given to potential benefits of each investment.

Stakeholder	Issue	AEMC response
	costs to a region which usually imports power.	
MEU (p. 14)	The change proposed by the rule implies that the load export charge will be based on the volume of energy transferred, as if the load was located at the border of the two regions. What is totally absent from the proposal is how this apparently simple philosophy will be addressed in the complexity that is the NEM and its structure which allows free flow of electricity between regions.	As outlined above and discussed in chapter 5, the Rules sets out the principles to be applied. The AER's pricing methodology guidelines and the transmission network service providers' pricing methodologies would set out additional implementation considerations.
MEU (p. 15)	There is a need to clarify if the approach is to require each interconnector to be assessed separately, or whether the flows on the two interconnectors are to be aggregated. Further there is a need to reflect the value of these counterflows to each region.	As discussed in chapter 6, the load export charge would be based on gross flows.
MEU (pp. 16-17)	Has considerable doubt as to the methodology which will be used to develop the load export charge for transferring power from one region to another. Considers there are a number of issues that would need to be addressed including whether the load export charge is an average of the net flows or is to be calculated for both regions; determining the appropriate cost allocation. The implication of the Rule change request is that cost allocation, when developing the load export charge, should reflect the times of maximum demand in the region, yet the Rule change proposal implies that the cost allocations will be made on the averaging used by most transmission network service providers.	The Commission notes that prices generally are based on a forecast value or historical amount. However, once actual flows are known, adjustments would be made such that the prices paid by consumers reflect the actual usage over time.
MEU (p. 27)	Due to the various bases on which the load export charge could be developed, there is a need for a	The Commission considers that it is desirable that a consistent approach across the NEM is adopted

Stakeholder	Issue	AEMC response
	high degree of prescription so that all consumers are treated on a consistent basis, bearing in mind that under the current approach to pricing methodology, almost every transmission network service provider has a different approach. It would be bizarre if the pricing approach used by one transmission network service provider resulted in a lower cost for the same service.	where appropriate while allowing a certain degree of discretion to the AER and transmission network service providers to adopt methodologies that reflect any unique circumstances in a region. Given the nature of the load export charge, the Commission considers the greater co-ordination between transmission network service providers would be encouraged in order to facilitate the required calculation processes.
NGF (p. 2)	Supports a load export charge with a locational and non-locational component of prescribed TUOS, and the charge from prescribed common services to be charged to transmission network service providers in the relevant interconnected areas.	The comments are noted.
AEMO (p. 4)	A consistent national approach needs to be determined, justified and implemented as part of introducing inter-regional TUOS.	As discussed above and in chapter 5, provisions under the Rules have been clarified to accommodate the introduction of the load export charge. In addition, the AER and transmission network service providers would be required to amend the pricing methodology guidelines and pricing methodologies respectively.
AEMO (p. 4)	The current Rules provide for an arbitrary 50:50 split into the locational and non-locational components of prescribed TUOS charges, which most regions adopt. The Rules also permit other approaches which seek to better reflect the intent of giving efficient price signals. One would expect that a consistent approach needs to be adopted nationally in this respect.	Discussion is outlined in section 5.4.3.

Stakeholder	Issue	AEMC response
AEMO (p. 4)	The Rules allow the adoption of either cost reflective network pricing or a modified cost reflective network pricing process. The Rules also provide little detail in the implementation of either approach. We consider that the whole approach needs to be checked to ensure that it works appropriately and deals with new forms of non-synchronous generation. Also considers that further work is required on consistency of approach.	The Commission understand that transmission network service providers, including AEMO in its capacity as a transmission network service provider in Victoria, are further analysing the application of the cost reflective network pricing and modified cost reflective network pricing methodologies to consider the impact of non-synchronous generation on these methodologies and that a Rule change request may be made to address any potential amendments required.
AEMO (p. 4)	The allocation of a proportion of the non-locational component to the load export charge needs to be questioned. If it remains, a consistent approach would need to be decided and implemented nationally at least in respect of the portion assigned to consumers in importing regions.	The composition of the load export charge is discussed in section 5.4.3.
AEMO (p. 5)	The locational component of prescribed TUOS service is based on cost reflective network pricing or modified cost reflective network pricing methodology which itself is based on the value that network assets provide to network users. Times of greatest value generally correspond to times of regional system peak and higher prices. An interconnector is no different in this regard - it will have greatest value to the network users in an importing region at times of peak demand. It is therefore more efficient for the inter-regional TUOS rules to limit the charges attributed to an importing region to the locational component of the exporting regions' prescribed TUOS charge and guiding when the appropriate survey period to measure and	The composition of the load export charge is discussed in section 5.4.3.

Stakeholder	Issue	AEMC response
	model system loading.	
AEMO (p. 6)	By its nature, the non-locational component of prescribed TUOS service charges is inefficient because no account is taken of its utilisation in the network by the importing region and it is not based on the cost reflective network pricing or modified cost reflective network pricing calculations. As such, non-locational charges do not appear to have these same efficiency outcomes. If the adjusted non-locational component is to be part of inter-regional TUOS charging regime, then consideration should be given to the option of a single national non-locational price where the NEM aggregate is allocated to all NEM transmission users independent of their region and particular interconnector flows.	The composition of the load export charge is discussed in chapter 5.
AEMO (p. 6)	A change in the methodology of allocating transmission costs nationally raises the possibility of a quantum change in a region's TUOS charges. This is also an issue for long term charges where movements in generation investment and dispatch have a material impact in TUOS pricing. This is both a practical implementation issue and also a concern in terms of efficient price signalling. The value of these measures in terms of their ability to drive more efficient outcomes needs to be questioned if they exhibit a high level of volatility from year to year.	Price volatility is discussed in section 7.4.
Energy Australia (p. 6)	Should the Rule change proceed, the overriding principles concerning cost allocation to intra-region load connections using the cost reflective network pricing allocation approach are also appropriate for	transmission network service providers through Grid Australia and AEMO, in its capacity as a transmission network service provider in Victoria, have prepared modelling on the potential impact of

Stakeholder	Issue	AEMC response
	interconnected loads. However, again, NEM participants would benefit from quantitative analysis being undertaken to determine the impacts.	the load export charge on the redistribution of transmission charges. Modelling results are discussed in section 7.4.
EnergyAustralia (p. 7)	An obligation needs to be placed on the transmission network service provider in the importing region to pass on [the locational component of the inter-regional TUOS] in a cost reflective manner to DNSPs in the region. In addition, considers that economic price signals would be preserved only if inter-region postage stamp price components were recovered on the same basis in the importing region.	The recovery of the load export charge is discussed in section 5.4.4.
Treatment of settlement residue proceeds; Market Network Service Providers		
Integral Energy (p. 2)	Questions whether the proposed change in the way that inter-regional settlement residue auction proceeds are returned to consumers in the importing region is likely to mean a net improvement in the locational signalling. Ideally, Integral Energy would like to see the Commission provide analysis that demonstrated that reducing the auction proceeds available to consumers who import across the interconnector doesn't over-value the congestion costs and therefore potentially distort the investment signal. It may also be appropriate to review the effectiveness of the change after a period of several years.	As discussed in section 5.4.5, the Commission considers that settlement residue auction proceeds should continue to be returned to consumers on a locational basis.
Grid Australia (pp. 7, 9)	The change to prevent the locational return of settlement residue auction proceeds to consumers in the exporting region is a material departure from	As above.

Stakeholder	Issue	AEMC response
	the principles. Considers that an alternative would be to include it as an adjustment to the prescribed TUOS services - pre-adjusted locational component - consumer connection points. This would then result in it being allocated in a manner closer to the proportional use of the assets.	
AEMO (p. 4)	The return of settlement residue auction proceeds would be more efficient through the locational component since the receipts arise from the use of the interconnector. Ideally the SRA auction proceeds would be netted off the amount transferred as the load export charge from the adjacent region and allocated locationally.	As above.
AEMO (p. 4)	The return of settlement residue auction proceeds would be more efficient through the locational component since the receipts arise from the use of the interconnector. Ideally the SRA auction proceeds would be netted off the amount transferred as the load export charge from the adjacent region and allocated locationally.	As above.
NGF (p. 2)	Supports settlement residue auction revenues, which are currently offset against a common service charge. Under this proposal, all consumers receive a more even spread of revenue from SRA auctions.	As above.
EnergyAustralia (p. 8)	Supports in principle the proposed change to return the settlement residue auction proceeds to consumers via the non-locational component of TUOS. Considers that the proposed change would be an improvement since the year on year variation of settlements surpluses leads to instability in the	As above.

Stakeholder	Issue	AEMC response
	cost reflective components of TUOS charges. However, notes that participants would benefit from quantitative analysis being undertaken to determine impacts for consumers.	
MEU (p. 26)	An MNSP should pay for the load export charge just as an exporting region transmission network service provider would do so for providing the same service directly across a regulated interconnector. This approach is consistent with the concept that the beneficiary pays for the provisions of assets needed to deliver the service to it, and reflects equity between consumers in an exporting region with the MNSP that uses those assets for generating profits for itself. Further it reflects the analogy of an MNSP being effectively a generator at the regional boundary.	The proposed provisions allow for any assets that are used by an MNSP, and where the costs for the assets are regulated, to be included in the load export charge. Otherwise, MNSPs are excluded from the load export charge provisions as the revenue and prices of MNSPs are not regulated where MNSPs earn their revenue from participating in the spot market.
NGF (p. 3)	Supports the exclusion of MNSPs from the proposed load export charge. As MNSPs are unregulated in the NEM, they are excluded from the pricing provisions of Chapter 6A of the Rules. Furthermore, MNSPs recover their revenues from the market and are not relevant to developing a load export charge. However, this need not limit charging of inter-regional TUOS charges between regulated Network Service Providers on either side of a MNSP.	MNSPs will be excluded from the load export charge.
AEMO (p. 6)	It is appropriate to exclude MNSPs from the inter-regional transmission charging process. However noting that inter-regional flows do occur over MNSPs and will need to be taken into account in the load flow modelling analysis and decisions	As above.

Stakeholder	Issue	AEMC response
	taken as to how to treat any sums allocated to their connection points in this process.	
EnergyAustralia (p. 8)	It would be inappropriate for the presence of Basslink (or any other MNSP) to inhibit the transfer of a TUOS charge between NEM regions. Considers that the arrangements will require ether: (1) the MNSPs, as interconnected parties, to receive TUOS charges from the exporting region and then to recover these charges from the importing region; or (2) inter-region TUOS charges are settled directly between the transmission network service providers connected to a MNSP. Considers the second alternative would be more efficient from the perspective of transaction costs and administrative complexity.	As above.
Transition and implementation		
Integral Energy (p. 1)	Supports the transitional arrangements proposed in the Consultation Paper.	Implementation and transitional requirements are discussed in chapter 6.
Grid Australia (p. 10)	With regards to administrative efficiency and the level of prescription for administrative processes, considers that specifying gross payments on a monthly basis with provisions for other arrangements to be agreed between parties would be reasonable. In the absence of a connection agreement or other enforceable instrument between neighbouring coordinating network service providers also considers it would be appropriate to specify default conditions or require terms to be agreed between parties. Does not believe that any	The Commission generally agrees that the level of prescription in the Rule proposed by the MCE in relation to the coordinating network service provider billing requirements appear to be reasonable and have been reflected in the Draft Rules.

Stakeholder	Issue	AEMC response
	additional prescription would be warranted.	
Grid Australia (p. 10)	There does not appear to be a material increase in the prudential risk to be managed as a result of the proposed requirements.	The comments are noted.
Grid Australia (p. 11)	It is appropriate for the AER to amend the pricing methodology guidelines to take into account the impacts of this Rule change process for proposed pricing methodologies submitted as part of future revenue applications.	The Commission agrees that the AER should amend its pricing methodology guidelines to reflect the new requirements for the load export charge. This is discussed in sections 5.4.3 and 6.4.3.
Grid Australia (p. 11)	Considers it is appropriate to have a general transitional provision allowing coordinating network service providers to modify their approved pricing methodologies to the extent required to implement the changes arising from the Rule change. As with the AEMO specific transitional provision it would be appropriate to have the AER approve these proposed changes. It would not be necessary for the guideline to be amended in order for the AER to assess the changes required to the pricing methodologies within the revenue control period.	The Commission agrees that transmission network service providers should be able to amend their pricing methodologies to take into account the new requirements. This is discussed in sections 5.4.3 and 6.4.3.
Grid Australia (p. 12)	Consistent with Grid Australia's previous submissions, strongly supports the adoption of 1 July 2012 as the earliest prudent commencement date. This is due to: • the requirement to amend pricing methodologies; • that Power link will be subject to chapter 6A of the Rules at that time; and	As discussed in section 6.4.4, the Commission considers that a 1 July 2012 implementation date would allow for sufficient public consultation on the pricing methodology guidelines and pricing methodologies, which would require amendment by the AER and transmission network service providers respectively.

Stakeholder	Issue	AEMC response
	• that the coordinating network service providers will be required to commence the calculation of the charge for neighbouring coordinating network service providers as early as January 2011 to meet the AEMC's proposed commencement date.	
EnergyAustralia (p. 10)	Does not believe that the proposed arrangements could reasonably be implemented by 1 July 2011. Elsewhere in its submission, it has stressed the need for modelling to be undertaken to identify the pricing impacts of the proposal before the policy details and the date of its introduction are established.	As above.
NGF (p. 2)	Proposes that the AER reviews the pricing methodology of all transmission network service providers to ensure they comply with their pricing methodologies following the implementation of a load export charge.	As above.
NGF (p. 3)	Proposes that the AER formulates any required changes to its pricing methodology guidelines to accommodate a load export charge. p. 2. Submits that the AER should refrain from adopting a new set of guidelines, independent of the pricing methodology guidelines, to develop a load export charge.	The Commission agrees that a separate set of guidelines would not be required and that the AER should be required to amend its existing pricing methodology guidelines.
NGF (p. 2)	Proposes that transmission network service providers apply a load export charge which could be implemented on a gross or net basis, but should be levied on the same basis throughout the NEM. They would set the charge based on the use of each	The Commission agrees that each transmission network service provider/coordinating network service provider would set charges based on each individual transmission network service provider's assets within its region and developed in

Stakeholder	Issue	AEMC response
	individual transmission network service provider's assets on either side of a region and ensure it was developed in accordance with their own pricing methodology. p. 2. Submits that the AER should develop consistent and transparent guidelines in gross or net payment procedures with transmission network service providers for the billing of inter-regional TUOS.	accordance with its pricing methodology. The AER will also be required to amend its pricing methodology guidelines to take into consideration the load export charge requirements.
NGF (p. 3)	coordinating network service providers should provide estimates of the load export charge to be levied to other coordinating network service providers before 15 May each year.	The Commission agrees that this would be required to allow each transmission network service provider to finalise its pricing proposal within the required timeframes. Discussion is outlined in chapter 6.
NGF (p. 3)	Credit issues between coordinating network service providers regarding the billing of inter-regional TUOS can be resolved between transmission network service providers without guidance from the AEMC.	The Commission agrees that additional guidance should not be necessary.
NGF (p. 4)	The charge could potentially impact consumers in each region differently as charges in one region increase and charges in another region decrease. Therefore, to deal with any unfortunate impacts associated with this charge, we support transitional provisions for the transmission network service providers to initially recover the load export charge through the non-locational component of TUOS and permit AEMO to revise its pricing methodology.	The Commission considers that the transitional arrangements under the Rule change request to allow the load export charge to be initially recovered on a non-locational component only was to allow some form of load export charge to be introduced without requiring all transmission network service providers to amend their pricing methodologies. However, given that the transmission network service providers will now be required to amend their pricing methodologies under the Draft Rule, the Commission considers that the transitional provision to allow the load export charge to be recovered on a non-locational basis only would not

Stakeholder	Issue	AEMC response
		be required.
AEMO (pp. 4-5)	The derivation and publication of transmission prices must always work to a tight timetable to allow them to be incorporated in distributor's tariffs an retailers' price offers. The national process therefore needs to fit to these requirements. Notes that , in order for locational TUOS charges to be recovered on the basis of consumers' proportionate use of network assets in the neighbouring region, transmission network service providers would need to calculate their load export charge and then redo the inter-regional transmission charge calculations again after they receive export load charges from neighbouring regions. This will result in an iterative process that ends only when all transmission network service providers resolve the inter-regional transmission charge prices in light of all other transmission network service providers' cascading load export charges. A practical solution will need to be identified in the testing and assessment process.	The Commission considers that by requiring the AER to amend the pricing methodology guidelines and to require transmission network service providers to amend their pricing methodologies, implementation issues would be able to be clarified. With respect to the timetable for the derivation and publication of distributor tariffs, the Commission considers that where possible, transmission network service providers should share up-to-date estimates with DNSPs.
EnergyAustralia (p. 2)	The proposal will introduce a greater level of price uncertainty, both initially and on an ongoing basis. To address this issue, considers that the publication date for inter-regional transmission charges should be 15 April of each regulatory year which would allow DNSPs to provide sufficient notice to consumers of likely changes to prices in the forthcoming year.	As above.
EnergyAustralia (p. 7)	In the likely event that the price impacts arising from changes to the TUOS allocation approach are material, a degree of prescription on the cost	The Commission considers that the AER's pricing methodology guidelines should clarify the types of assets that should be included, which would be

Stakeholder	Issue	AEMC response
	allocation approaches used by individual transmission network service providers will be necessary. The Rules should also specify the types of assets to be included in the cost allocation.	consistent with the current provisions under the Rules.
EnergyAustralia (p. 10)	The AER's existing transmission pricing methodology guidelines do not appear to require modification to enable the recovery of inter-regional TUOS charges.	As discussed in sections 5.4.3 and 6.4.3 and noted above, the AER will be required to amend its pricing methodology guidelines.
EnergyAustralia	Noted that transitional provisions for the introduction of inter-regional transmission charging could be implemented at the transmission level, at the distribution level, or some combination of the two. Their interaction with existing pricing constraints for both transmission and distribution charges will also need careful consideration, to ensure that: (1) the impacts on the transmission and distribution connected consumers are balanced; and (2) each transmission network service provider or DNSP is not prevented from recovering the regulated revenue for its prescribed services.	The Commission notes that as the load export charge would be recovered from consumers through the existing components of the prescribed transmission service charges, a new category of charges would not be created in terms of the amounts to be recovered by DNSPs. For this reason, DNSPs and retailers should be able to pass through these costs to the same extent as existing network charges are passed through. With respect to ensuring that the impacts on transmission and distribution connected consumers are balanced, the Commission notes that the locational component of the load export charge is based on proportionate use of the transmission network, as discussed in section 5.4.3.
Other issues		
Gallaugher & Associates (p. 2)	Suggests that the proposal as presented is overly prescriptive. Considers an alternative would be to simply obligate the NTP to prepare and publish a methodology for quantifying the charges in accordance with some limited but quite well defined	The Commission has taken into consideration the requirement to achieve an appropriate balance between the level of prescription under the Rules and the ability for the AER to establish guidelines to assist with the implementation of the load export

Stakeholder	Issue	AEMC response
	objectives, and to prepare, publish and administer operating procedures for its implementation. In this way the inter-regional charges would all be determined on a consistent basis across all interconnectors.	charge. This is discussed in section 5.4.3.
Gallaugher & Associates (p. 2)	The proposal will at best only marginally enhance achievement of the NEO. Considers that given the gross inadequacies of existing transmission regulatory and pricing arrangements in the NEM from an economic efficiency standpoint, it is not sensible to base one's entire argument for any inter-regional network charging proposal including this one around the question of economic efficiency and the NEO.	The factors that must be taken into consideration in any Rule change process is set out under the NEL. These requirements and the Commission's consideration of them are set out in Chapter 2.
Gallaugher & Associates (pp. 2-3)	The Consultation Paper should have included information on the potential impact of the proposal on existing transmission cost allocations and TUOS charges in each of the NEM regions. Considers that when quantitative data is considered it will show that inter-regional transmission charging is quite immaterial and not worthy of the amount of time and attention it has already attracted and will continue to attract until it is resolved.	As discussed above, the Commission notes that transmission network service providers, including AEMO in its capacity as a transmission network service provider in Victoria, have undertaken modelling of the potential impacts of the load export charge on the redistribution of transmission charges. Consideration of the modelling outcomes are discussed in section 7.4.
Hydro Tasmania (p. 2)	Supportive of the request for the public disclosure of an assessment of the magnitude of net inter-regional payments based on historical network flows. However considers it would be unwise to assume that the historical flows will be a reliable guide to future performance, given the projected large growth in renewables in South Australia and	As discussed above, modelling outcomes are outlined in section 7.4.

Stakeholder	Issue	AEMC response
	the untapped wind energy potential in Tasmania.	
Gallaugher & Associates (p. 3)	The Consultation Paper should have disclosed in quantitative terms what in fact has occurred since NEM commencement on each interconnector in terms of energy flows, inter-jurisdictional payments; interconnector residue payments and settlement proceeds.	The Commission notes the comments made and consideration of these issues are set out in section 7.4.
Hydro Tasmania (p. 2)	It would probably be more pertinent for an assessment to be provided on the basis of a forward-looking view but recognising that a degree of uncertainty will always surround projected system demand, generation location and consequent power flows. The materiality of net inter-regional payments may be low today but is unlikely to remain so.	The Commission notes the comment made and notes that if changes in inter-regional flows occur in the future then it would be expected that the load export charges would be reflective of the changing utilisation of inter-regional transmission assets.
MEU (p. 3)	There are higher priority issues that need reviewing with respect to the transmission revenue and pricing regulatory framework. Concerns over the potential in the incidence of blackouts and brownouts in South Australia indicated in the CRA modelling for the AEMC Climate Change Review have not been addressed as the AEMC's final report was silent on this issue.	The comments are noted.
MEU (p. 5)	Despite the amendments to Chapter 6A of the Rules there has been almost no investment in increasing inter-regional electricity flow capability. Considers that the causes of this lack of investment in inter-regional transmission is a much higher order issue for the NEM than this Rule change request	The comments are noted. Transmission Frameworks Review will be examining a broad range of issues. It is noted that the Commission had published an Issues Paper for this review and is currently in the processes of reviewing the submissions received.

Stakeholder	Issue	AEMC response
	which merely allocates costs between consumers.	
MEU (p. 19)	The MEU has long been a supporter of the view that justification of interconnector augmentation should include the benefit consumers get from the greater competition between generators that results from this investment. The MEU considers that its view has been denied by the AEMC on the basis that to incorporate such in the regulatory test does not provide a net benefit to the market but it is a "transfer of wealth" between generators and consumers. The MEU considers that this is inconsistent with the fact that as consumers pay for transmission services, they should not have to share the benefit of the investment with generators.	The Commission notes that generators do contribute to transmission charges through prescribed entry charges. In addition, as noted above, the Transmission Frameworks Review will also include consideration of the broader framework.
MEU (p. 20)	The AEMC has made no attempt to quantify the benefit the consumer in the importing region gets from using the assets in the exporting region, but assumes that they will exceed the also unquantified cost to use the assets in the exporting region. It is axiomatic in the Rules that a consumer should not be required to pay more for a service than the benefit it receives; therefore if the cost of the service exceeds the benefit a consumer gets, then it should not pay more than the value of the benefit it receives.	Modelling results are discussed in section 7.4.
AEMO (p. 7)	Unsure what meaning the proposed definition of prescribed TUOS services is attempting to convey but assume that it is trying to include benefits accruing to regions that are connected to the original region by an intervening region(s). If this is indeed the intention, it should probably be made	The Commission notes that the underlying concept for the load export charge is that neighbouring regions should be treated in the same way as consumers within the region. For this reason, the definition of prescribed TUOS services has been expanded, consistent with the existing definition, so

Stakeholder	Issue	AEMC response
	more explicit in order to remove potential ambiguity.	that transmission network service providers from the neighbouring region are treated in the same way as connection points within the region.
EnergyAustralia (pp. 3-4)	Regional interconnections comprise lengthy, high capacity, high cost transmission assets connecting remote generators to jurisdictional interfaces. However, under the inter-regional TUOS proposal, generators do not pay charges for their use of the capacity of shared network assets. Generators in the exporting jurisdiction can make free use of these assets and the entire cost of the assets be borne by the downstream consumers in the importing region.	The Commission notes that these related issues will be further considered under the Transmission Frameworks Review.

A.2 Submissions to discussion paper

Stakeholder	Issue	AEMC Response
MEU	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 change is put at risk. (P4)	The rule change is limited to transmission charging and so broader issues of costs and pricing are not addressed. However, it is not considered that the rule change puts competitive neutrality at risk.
	Whilst satisfying cost-reflectivity appears reasonable, net benefits are questionable, given the issues and complexities involved. (p5)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.

Stakeholder	Issue	AEMC Response
	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. (P4)	If spin-off benefits can be provided at no additional cost there is no reason to charge for them. Indeed, doing so could reduce allocative efficiency.
	Introducing an inter-regional charge will not result in the lowest cost for consumers as local generation might give a lower cost to consumers than imported power when the inter-regional charge is added (P4) inter-regional transmission charge does not affect generation dispatch, which remains geared to providing energy to consumers at lowest cost.	inter-regional transmission charge does not affect generation dispatch, which remains geared to providing energy to consumers at lowest cost.
	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 (P4)	It is acknowledged the behavioural change caused by inter-regional transmission charge may be modest, but that should be sufficient to provide benefits that outweigh the implementation costs.
	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 risks and costs. (P4)	The Commission notes that all consumers have some potential to modify their consumption in response to changing electricity prices.
	An inter-regional transmission charge needs to reflect basic actualities. For example: the use of Victorian assets by Tasmanian consumers is small; Victorian generation is closer to the Vic-NSW border than NSW generation, so Victoria will pay a net	Since the inter-regional transmission charge is based on the same cost reflective network pricing method as is used intra-regionally, the inter-regional transmission charge should reflect outcomes in a similar way to existing intra-regional TUOS charges.

Stakeholder	Issue	AEMC Response
	inter-regional transmission charge to NSW even when interconnector flows are symmetrical. (P4)	
	Perverse and inequitable outcomes are still likely even with the new approaches to the inter-regional charge (p4)	Although there could be some perverse outcomes, the modelling undertaken suggests the inter-regional transmission charge are fair and reasonable.
	Any export charge does not impinge on generator location decisions which have a major impact on the size of the export charge (p4)	Introducing generator charges for inter-regional transmission charge would result in a significant increase in the cost of implementation for a minor part of revenue recovery.
	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 (p4)	Introducing generator charges for inter-regional transmission charge would result in a significant increase in the cost of implementation for a minor part of revenue recovery
	If prices show significant variability year on year, then the price signal will not improve locational decisions of generators and consumers (p4)	Agreed. Modelling indicates that the cost reflective network pricing variant defined in the second draft rule has relatively low year-on-year variability.
	Variability in costs is a major concern in regions that have a large degree of weather risk (eg Tasmania in drought conditions) (p5)	Whilst weather variations may cause some variability in inter-regional transmission charge, these are likely to be small compared to associated variations in wholesale prices.
	Where there are two interconnectors, the actuality of the flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations (p4)	This appears to be a dispatch issue which is beyond the scope of the rule change.
	Any changes in usage that is caused by the introduction of inter-regional charging will impact the	Impact on the spot market will be small and unlikely

Stakeholder	Issue	AEMC Response
	spot market and this needs to be taken into account (p4)	to be material.
	Options considered requiring a normalisation of cost allocations in all region might not be in the interests of consumers. (p4)	The second draft rules does not require any change to cost allocation (ie asset valuation) methods.
	The nominated new approaches are not supported by quantitative analysis and modelling to ascertain the economic costs and benefits. (P5)	It is expected that the administrative costs will be modest and likely to be outweighed by the benefits
AER	The AER suggests that the AEMC also consider the costs and benefits of the proposed model relative to a "do nothing" option (p1)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	The AER prefers NEM-wide cost reflective network pricing [as it is most cost-reflective]…However, should the obstacles to implementing this option within a reasonable timeframe prove insurmountable, then the AER considers that a simpler option, such as modified load export charge, is likely to constitute an improvement on the status quo (p1)	Agreed. It is considered that the extra costs of administering NEM-wide cost reflective network pricing (compared to modified load export charge) would outweigh the incremental benefits, at least in the short-term.
	Changes to the transmission network service providers' pricing methodologies have the potential to cause price shocks to consumers. By decoupling consideration of inter- and intra-regional transmission charging, consumers may be exposed to two sets of price shocks in relatively short succession (p2)	Modelling suggests that the price impact of the inter-regional transmission charge will be modest.

Stakeholder	Issue	AEMC Response
	The inclusion of postage stamped components is likely to undermine the intent of the policy by obscuring the locational signals associated with inter-regional charges (p1)	The draft rule excludes postage stamp charges from the calculation of inter-regional transmission charge.
AEMO	We think that the options proposed [modified load export charge and NEM-wide cost reflective network pricing] risk creating complexity without necessarily advancing the [pricing] objectives. (p3)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	Interconnector investment can depend on a number of factors but will usually have more to do with gaining access to more efficient reserves of generation from neighbouring regions than a region can provide on its own. (p1)	Sharing of reserves will be reflected in interconnector flows and hence in modified load export charge prices.
	Ideally [an efficient] price would be calculated on a prospective basis, recognising the future costs that will be incurred as a result of additional load at a point on the network. Given the difficulties and vagaries of this theoretical approach, we agree that in relation to ordinary consumer load points, the cost reflective network pricing approach adopted is a reasonable proxy. (P1)	Agreed. This is the reason for choosing cost reflective network pricing for inter-regional transmission charge.
	If this price signal is effective, it will reward consumers whose behaviour contributes to deferring network investments. Therefore, by designing a regime that properly identifies the usage in relation to network capacity, and pricing accordingly, it will also indirectly inform the network investment required to accommodate those users (p1)	Agreed

Stakeholder	Issue	AEMC Response
	Having a “net” load export charge at the border might provide unreliable and confusing investment signals. When, over the course of a year you have flows going in opposite directions, you are left with a net charge that does not necessarily inform investment needs (p1)	If there are flows in both directions, the net inter-regional transmission charge is likely to be small and so little different to the status quo. The inter-regional transmission charge is most important when flows are predominantly in one direction, meaning that the status quo is inefficient.
	Therefore, [modified load export charge] is not suited to the Victorian and NSW regions because it does not allow those regions to charge other regions for energy wheeled across its network. In this respect, [NEM-wide cost reflective network pricing], despite its complexity might represent a better solution. (p3)	The impacts of demand on non-neighbouring regions is likely to be small and the value of pricing that impact is not sufficient to offset the higher administrative costs of NEM-wide cost reflective network pricing.
	We believe that [modified load export charge and NEM-wide cost reflective network pricing] create similar issues to the original inter-regional transmission charge proposal. While some methodologies are standardised, there is still the ability to differentiate approaches of determining which assets do and do not contribute to inter-regional flows. (p3)	In the second draft rule, all assets are included in the cost reflective network pricing run used for inter-regional transmission charge and the method is essentially standardised.
	Ultimately, classifying assets that are used for, or contribute to, inter-regional flows is a variable that each coordinating network service provider will need to interpret and apply to the transmission assets within its region. This can, particularly over time create inconsistencies with their regional neighbours (p3)	In the second draft rule, assets are not explicitly classified. All assets are included in the cost reflective network pricing run used to calculate modified load export charges.
	[under NEM-wide pricing] if a coincident peak	Agreed. It may be difficult to establish such a

Stakeholder	Issue	AEMC Response
	method of determining cost allocations were adopted, there would need to be some agreed way of establishing meaningful peak periods common to the entire NEM (03)	definition. That is one reason why the “365C” approach is required under the draft rule, rather than a 10-day approach.
	We think that [NEM-wide cost reflective network pricing pricing] is a better option because not only would this approach ensure that each load point in the NEM is treated consistently, it dispenses with the necessity of having to treat interconnectors as notional connection points at the regions’ borders. (p2)	NEM-wide cost reflective network pricing is preferred in principle for this reason. However, it has some practical difficulties which would make it costly to implement and administer solely for inter-regional transmission charge.
	[Under a LEC method] differing valuation and apportionment methodologies between those regions, will cause consumers to face unclear and inconsistent locational pricing signals as each region charges load export charges based on differing apportionment methods from their neighbours (p2)	Agreed.
	The difficulty that [cost sharing] faces is that because usually, most of the benefit from interconnectors flows to one region, obtaining agreement to contribute to the costs from the region that enjoys the lesser benefits might prove to be a challenge (p2)	Agreed.
	A single TUOS pricing authority would be the best method of maintaining an efficient inter-regional transmission pricing regime because it is able to align cost allocations for all transmission assets in the NEM more consistently and ensure that	Aligning cost allocations is likely to be costly and would not be expected to materially change modified load export charge levels.

Stakeholder	Issue	AEMC Response
	consistency is maintained for the longer term. (p2)	
Department of Primary Industry	DPI has a different understanding of how the various elements of economic efficiency are defined and how they should be applied to the issue of inter-regional transmission pricing than that set out in the Discussion Paper (p4)	The AEMC notes the DPI's comments.
	The Discussion Paper argues that while transmission charging should encourage both the so called static efficiency and dynamic efficiency, that the unique characteristics of transmission results in conflicts between them. DPI does not agree with this perspective (p7)	The AEMC notes the DPI's comments.
	DPI notes the Discussion Paper's argument that an efficient charging regime would require trade-offs between allocative and dynamic efficiency. DPI disagrees with this analysis and notes that efficient markets are in effect markets that are productively (p11) and allocatively efficient over time.	Pricing above short-run cost reduces short-run efficiency but promotes long-run efficiency. The economic theoretical distinction between the short-run (using existing capital) and the long-run (allowing for capital investment) is uncontentious. To merge these two timescales into "over time" is not helpful to the economic analysis.
	However, when a strict use of an appropriate test for cross-subsidies is applied (cost of interconnected network versus stand-alone networks), it is unlikely that they would exist for existing networks. (p2)	It is acknowledged that this may be true based on a strict economic definition of cross-subsidy. However, the existence of cross-subsidies is not necessary to create impediments to inter-regional expansion
	In essence, intra-regional transmission investments within each region have been largely undertaken to support intra-regional transmission capability (p7)	Agreed. This is due to impediments embodied in existing transmission charging arrangements, which the rule change is seeking to remove

Stakeholder	Issue	AEMC Response
	One of the key rationales on which the proposed draft rule change is based, that the existing arrangements result in implicit cross-subsidies, is not substantiated by the facts and the manner in which intra-regional transmission systems have been planned and constructed historically. (p7)	The Commission views that there are other benefits derived from an inter-regional transmission charge that are not linked to removal of cross subsidies.
	DPI does not support the modified load export charge or NEM-wide cost reflective network pricing charge as the assets to be included do not reflect the true incremental cost of assets involved in establishing inter-regional transfer when compared with the cost of providing stand-alone regional networks (the true measure of any cross subsidy); . (P14)	Since network planning is not actually done on a regional standalone basis, the hypothetical costs of doing so are irrelevant to efficient pricing. Efficient prices should signal future costs under the actual planning regime.
	The regulatory arrangements promote network expansion independently of decisions by consumers to connect. The five year regulatory pricing decisions tend to be based on broad estimates of load growth with transmission development designed to meet those estimates (p10)	Network expansion is predicated on the RIT-T, which does take into account current and projected demand
	DPI considers that there is no economic benefit in using LRMC pricing linked to network usage for existing consumers as the locational decision has been made and pricing usage above congestion costs will lead to a loss of allocative efficiency. In relation to potential consumers, some variation in fixed costs to reflect expansion costs at different locations may be warranted. (p10)	While the locational decision has been made it is not the relevant decision that a consumer can make in a cost reflective network pricing approach to transmission network service provider pricing.

Stakeholder	Issue	AEMC Response
	DPI does not support the modified load export or NEM-wide cost reflective network pricing charge as it proposes charging on an energy flow usage basis, which may be misinterpreted in a manner that is inconsistent with the benefits and rationale for transmission investments. (P14)	It is not expected that the use of a cost reflective network pricing method will be interpreted as anything other than an extension of intra-regional TUOS pricing to inter-regional flows.
	DPI considers that for existing networks, only cross-subsidies that exist through the application of a strict cross-subsidy test should be included as assets for the inter-regional transmission charge. (p2)	The Commission views that there are other benefits derived from an inter-regional transmission charge that are not linked to removal of cross subsidies.
	DPI considers only new assets that demonstrably enhance the capacity of inter-regional transfers, including any investment to maintain transfer capacity that would otherwise decline, should be included in the asset base for the inter-regional transmission charging regime (p2)	The Commission addresses this point in section 13
	DPI does not support the modified load export charge or NEM-wide cost reflective network pricing charge as it does not specifically limit charging to assets that are demonstrably involved in transferring electricity between regions . (P14)	Any assets whose costs are allocated inter-regionally by cost reflective network pricing are “inter-regional assets” in that they are used in inter-regional transfers.
	DPI does not support the modified load export charge or NEM-wide cost reflective network pricing charge as it does not differentiate between investment to support enhanced intra-regional transmission capability and inter-regional transmission capability . (P14)	Any assets whose costs are allocated inter-regionally by cost reflective network pricing are “inter-regional assets” in that they are used in inter-regional transfers. There is no clear distinction between “inter-regional” assets and “intra-regional” assets. Many assets will play a dual role.

Stakeholder	Issue	AEMC Response
	DPI does not support the modified load export charge or NEM-wide cost reflective network pricing charge as it does not differentiate between existing sunk investments and future investments; . (P14)	The Commission addresses this point in section 13
	The short run marginal price of transmission (congestion cost) should be retained as the only form of locational price signal for existing network users. The short run marginal price plus any fixed costs (allocated as set out below) would provide efficient signals to potential users. (p12)	The AEMC notes the DPI's comments
	Using the non-locational and common service charges for existing networks in addition to the SRMC to send locational signals will result in excessive prices, which would lead to allocative inefficiency. Hence any application of cost-reflective pricing should avoid allocating the non-locational and common service charges on a locational basis. (p6)	Agreed. The draft rule excludes postage stamp charges from the calculation of the inter-regional transmission charge
	DPI does not support the modified load export or NEM-wide cost reflective network pricing charge as it proposes to incorporate components of non-locational and common service charges which will reduce allocative and dynamic efficiency; and,)	The draft rule excludes postage stamp charges from the calculation of the inter-regional transmission charge.
	As changes in the type and location of the generating mix will cause most of the changes in generation patterns and network flows (creating the need to reconfigure and expand existing networks) and as generators do not contribute towards the recovery of fixed costs, the inter-regional	The AEMC argument is that changes in the generation pattern are changing the flows on interconnectors and TUOS pricing needs to be reformed to reflect this change. Introducing generator charges for inter-regional transmission charge would result in a significant increase in the

Stakeholder	Issue	AEMC Response
	transmission charge would appear to have little economic merit (as it would not be levied on the participants driving the changes) (p10-11)	cost of implementation for a minor part of revenue recovery.
Grid Australia	GA submits that the Commission would find it difficult to demonstrate that extending the existing transmission pricing methods to inter-regional transmission pricing would in fact generate net benefits in accordance with the NEO (P8)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	It is unclear to GA how a “causer or beneficiary pays” concept relates to marginal cost pricing (p7)	Agreed. This determination refers simply to “pricing efficiency”
	Current transmission pricing methodologies are at best approximations to marginal cost pricing (p8)	Agreed. Given lumpy investment it is difficult to exactly measure “marginal cost” for transmission.
	Inconsistencies between replacement cost models present a fundamental obstacle to the [NEM-wide TUOS] (p7)	Agreed. This is one of the major reasons why the second draft rule uses an modified load export charge method, rather than NEM-wide cost reflective network pricing
	As noted in previous submissions, inconsistencies between replacement cost models used by transmission network service providers are to be expected but do not impact on the calculation of a load export charge at the boundary of a region (p6)	Agreed. This means that the administrative costs of the modified load export charge method are modest.
	The measure of demand used for the calculation of prices only affects consumers within a region and is not expected to impact on the calculation of inter-regional charges (p6)	Agreed. The second draft rule does not require demand measures.
	While the modified cost reflective network pricing methodology is slightly more complex than standard	Agreed. The main concern around the modified cost reflective network pricing method is the

Stakeholder	Issue	AEMC Response
	there is limited scope for subjectivity in the calculation of line ratings and utilisation factors (p4)	administrative costs for those transmission network service providers which do not currently use it.
	The modified cost reflective network pricing methodologies adopted by both ElectraNet and Transend deliver appropriate price signals to those consumers on lightly loaded radial lines. It does not materially impact on the prices within the meshed network or points of connection to adjacent regions. (p4)	Agreed. That is why the second draft rule requires use of the standard cost reflective network pricing. Although it may be appropriate for transmission network service providers currently using modified cost reflective network pricing to also use it for calculating modified load export charges, transparency is improved (and administrative costs not significantly increased) if all transmission network service providers use standard cost reflective network pricing.
	AEMO's [10E] methodology doesn't capture the conditions necessary for a credible inter-regional charging methodology (p5)	Agreed. During regional system peak, interconnectors are likely to be importing and so calculated modified load export charges would be too low.
	GA considers that the [10E] method is inappropriate as a mechanism for sending demand side participation signals	Agreed
	The flows on interconnectors at times of system peak are not necessarily consistent with those expected to drive network investment (p5)	Agreed. That is one reason why the "365C" approach is required under the draft rule, rather than a "system peak" approach.
	With the exception [of 10E vs 365C] there is no evidence that the minor differences between intra-regional pricing methodologies will impact materially on the original load export charge (p3)	The modelling would appear to confirm this view. However, since the definition of peak period (10E or 365C) is material, a LEC would give rise to non-transparent pricing between Victoria (that uses 10E) and other regions (that use 365C).

Stakeholder	Issue	AEMC Response
	"recovers the costs of an existing network" implies the full inclusions of sunk costs in prices on all occasions (p7)	That was not the intended meaning.
	GA remains firmly of the view that the load export charge should be based on the locational component of prescribed transmission services only. (p5)	The draft rule excludes postage stamp charges from the calculation of the inter-regional transmission charge.
	There is no obvious benefit in pricing sunk costs at the boundary between regions (p8)	Noted.
	Priority should be given to ensuring that most transmission network service providers would have the option of amending their pricing methodologies to the extent required to remove the requirement for a two-step cost reflective network pricing [method] (p8)	The AEMC agrees that there is no inherent benefit from pursuing a two-step methodology. However, it is unclear how the desired pricing outcome can be achieved without requiring a separate calculation of the inter-regional transmission charge.
	[The rules] should allow Victoria to maintain its [10E] method for intra-regional pricing and do a second run based on a methodology consistent with the national principles, while all other transmission network service providers could…implement inter-regional charging via relatively minor amendments to their existing pricing methodologies (p9)	The second draft rule does not seek to amend the method used by transmission network service providers for intra-regional transmission pricing.
	The new options appear to be administratively complex to implement as they represent a shift away from the existing methodology transmission network service providers use for their intra-regional charging. This will add further complexity to an	It is anticipated that the additional administrative costs of modified load export charge (compared to LEC) will be very modest. It is acknowledged that the different approaches to intra-regional and inter-regional TUOS pricing will create some

Stakeholder	Issue	AEMC Response
	already complex pricing regime which will not aid transparency to consumers. In addition it can be expected to take longer to implement the new options. (p3)	additional complexity and loss of transparency.
	GA considers that the Commission should maintain the current principles-based approach to pricing in the Rules (p8)	The Commission has maintained the pricing principles for transmission charging.
	The degree to which the Commission wishes to deal with the pricing of sunk costs could also be important in deciding between the cost reflective network pricing based and cost sharing options(p8)	The Commissions approach to pricing sunk costs for inter-regional transmission charge purposes is the same as adopted for intra-regional pricing.
	Principles in the Rules should be limited to (a) choice of load conditions (b) quarantining from each other under/over recoveries of intra-regional and inter-regional charges (c) ensuring that SRA proceeds only benefit consumers in the region intended (d) ensuring that only the prescribed locational component is to be charged across borders (p9)	The Commission has sought to isolate the impact of inter-regional transmission charge from the other aspects of Transmission pricing such as SRA proceeds.
	The principle defining the [modified load export charge] methodology should be defined in the rules with the detail to be defined in the pricing methodology guideline and the pricing methodologies in consultation with the AER. `(P15)	Including the detail in the second draft rule makes it clear for all stakeholders the approach the transmission network service provider must adopt.
InterGen	IGA considers that broadening the consideration of the Discussion Paper to include non-prescribed services is relevant to the overall efficiency of any proposed regional transmission charging regime	Unregulated services fall outside the scope of the proposed rule change.

Stakeholder	Issue	AEMC Response
	and methodology (p3)	
	IGA submits that any new rule associated with inter-regional transmission charging should be applied to both new and existing infrastructure (including unregulated assets) (p1)	While the Commission has included existing assets within the operation of the second draft rule, unregulated services fall outside the scope of the proposed rule change.
	IGA submits that there may be further opportunities to improve cost-reflecting network pricing by expanding the scope to include negotiated or unregulated services (p1)	Unregulated services fall outside the scope of the proposed rule change.
AGL Energy, Alinta Energy, International Power GDF-Suez, LYMMCo	This analysis of benefits relevant to each purpose could be derived from the analysis under the RIT-T process, or from any alternative analysis of benefits that might be applied. (p4)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.
	Any inter-regional transmission charge should be on going and stable unless and until a network planning decision within the region re-allocates part or all of the relevant network capability to another purpose i.e. under-utilisation, of itself, should not lead to re-allocation of costs, (p1)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.
	the superior methodology of allocating cost, ex ante, on the basis of causation, is not available for most transmission investments within a region (P5)	There is no reason why this could be applied within a reason, but also no reason to apply it, given that efficient pricing is to signal future costs, not allocate historical costs
	We propose that any inter-regional transmission charge should be based on the true causation of cost in the transmission network, namely the decision to invest in new transmission assets, and should apply where the justification of new	Expectation of future flows must be predicated on existing consumption patterns and interconnector use. Thus, charging based on this use is consistent with the expressed “causer-pays” philosophy.

Stakeholder	Issue	AEMC Response
	investment is based, in part or entirely, on the expectation of persistent energy flows from or through the constructing region, (p1)	
	We accept that ex-post cost allocation (such as cost reflective network pricing) is unavoidable for many transmission costs within a region. This situation is one where charges based on causation are beyond practical reach and a plausible locational cost signal is the best that can be achieved (p3)	There is no significant distinction between inter-regional and intra-regional in this respect. For this reason, cost reflective network pricing is considered to be an efficient pricing method for inter-regional transmission charge.
	The cases where ex-post cost allocation can be avoided include investment for new generator access, new large consumer supplies, and interconnectors. In each of these cases, the cause of the cost will be clear at the time that the investment decision is made. (P3)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. An “ex ante” approach cannot signal future costs as prices will not respond to changing consumption patterns.
	Since the actual costs of the transmission network are determined on an ex-ante basis, we contend that in all those cases where cost can be allocated on the same ex-ante basis, it should be. (p3)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. An “ex ante” approach cannot signal future costs as prices will not respond to changing consumption patterns.
	Where assets were built as Scheduled Network Services, and subsequently converted to regulated interconnectors, the AER has had the opportunity to divide the costs appropriately between market regions (p3)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs
	The costs of the existing network are already being recovered. The allocation of costs between the regions is generally based on the original purposes for the investment. As discussed above, we believe that there would be no benefit in relation to the	The purpose of efficient pricing is to signal future costs, not to allocate historical costs.

Stakeholder	Issue	AEMC Response
	National Electricity Objective in reallocating these sunk costs. (P7)	
	The assessment criteria of “provides a signal for future investment” should be secondary to “administrative efficiency”, “transparency” and “stability and regulatory certainty, including cost impacts”. (P7)	Agreed. The “investment signal” arises only indirectly as a consequence of demand response to the TUOS prices.
	We do not support any inter-regional transmission chargec based on the cost of existing transmission assets (P1)	The cost of existing assets embedded in the cost reflective network pricing method is a proxy for the cost of future investment which the inter-regional transmission charge signal.
	We submit that there is no justification in terms of the National Electricity Objective in now undoing these past decisions, by re-allocating these historical and sunk costs. (p2)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs. If the demand pattern changes then TUOS prices should change.
	This use is almost entirely beyond control as power flows are determined by physics, not by intentions. (p4)	The asset use is determined by demand, which is under the control of the consumer.
	As we have noted earlier, such IR transmission charges should be independent of the actual power flows on the Network (p5)	Actual power flows indicate the level of utilisation of existing assets which, in turn, indicates the likely need for, and cost of, transmission expansion.
	The share of the asset cost previously supported by the inter-regional transmission charge would then be allocated in accordance with the new use of the capacity, for example to a generator if it now supports a new generator access. (P5)	The purpose of efficient pricing is to signal future costs, not to allocate historical costs

Stakeholder	Issue	AEMC Response
	We note that opportunistic usage of the network for purposes other than those originally envisaged has no material impact on capital charges, operational costs or maintenance costs. (P7)	Agreed. But the TUOS charges are not intended to reflect the cost of using the existing network but rather the expected future cost of expansion based on current and projected use.
	We are proposing that only new inter-connector assets are included in the inter-regional transmission charge, and have excluded sunk charges because in addition to the reasons given above; this has the benefit of reducing the price impact of the inter-regional transmission charge (P7)	By definition, any assets whose costs are allocated inter-regionally by cost reflective network pricing are “inter-regional assets” in that they are used in inter-regional transfers. Modelling indicates that price impacts under the draft rule are reasonable and do not need to be reduced.
	The short-run marginal costs of transmission are not directly met by transmission network service providers, are uncertain and often perverse in their impact on a transmission network service provider and we therefore contend that no attempt should be made to include them in an inter-regional transmission charge (p2)	Agreed. Only transmission asset costs are included in the second draft rule.
	We note that these [inter-regional transmission charges] have no locational significance in either the sending or receiving region, and therefore expect that they would apply to costs recovered on a “postage stamp” basis on both regions (P5)	The Commission is of the view that recovery of these charges through the locational component improves the pricing signal sent to consumers. While recognising that this signal is weakened by combining it with the intra-regional charge it is still an improvement on a postage stamp basis.
Office of energy planning and Conservation (Tasmania)	There are difficulties though in including some existing assets: such as Basslink (P6)	The rule change applies only to regulated network assets. Basslink is unregulated.
	some form of smoothing mechanism needs to be introduced such that charges do not vary	Modelling suggests that annual variations in inter-regional transmission charge are modest and

Stakeholder	Issue	AEMC Response
	significantly and unpredictably from year to year. (P2)	so a smoothing mechanism is not required.
	It is not clear to what extent non-neighbouring regions utilise each other's transmission assets. This needs to be modelled to determine to what extent the issue is material. If it is significant then option 3 would become a strong candidate for being the preferable option. (P5)	It is believed that the impacts of demand on non-neighbouring regions is small and the value of pricing that impact is not sufficient to offset the higher administrative costs of NEM-wide cost reflective network pricing.
	If cost-sharing or NEM-wide cost reflective network pricing becomes the preferred option, asset valuation will need to be consistent for those methodologies to be applied. Asset valuations are non-trivial exercises and it is important to avoid excessive work and duplication of effort.(P4)	Agreed. This is one of the major reasons why the draft rule uses an modified load export charge method, rather than NEM-wide cost reflective network pricing
	While a standard cost reflective network pricing may be easier to implement in a uniform manner, a modified cost reflective network pricing provides better locational signalling and is therefore more aligned with driving efficient utilisation of the network.(p3)	Use of modified cost reflective network pricing, rather than standard cost reflective network pricing, would not materially change the level of modified load export charges but would impose significant cost to those transmission network service providers who do not currently use it.
	The 10 day system peak methodology may lead to volatility in locational price if major industrial consumers change their behaviours. (p4)	Agreed. Modelling results would seem to confirm this volatility.
	Inter-regional transmission charges must not include costs not directly relevant to the provision of transmission services in the neighbouring jurisdiction (p2)	The second draft rule excludes postage stamp charges from the calculation of inter-regional transmission charge.

Stakeholder	Issue	AEMC Response
	The modified LEC would be preferable to the original LEC as it is based on application of a consistent methodology. This is on the proviso that the benefits of carrying out an additional uniform national cost reflective network pricing methodology outweigh the additional administrative costs of doing so (P4)	It is anticipated that the additional administrative costs of modified load export charge (compared to LEC) will be very modest
	Consumers / stakeholders may find differences in methodology between intra and inter regional charging confusing, adding to an already complex system of calculating prescribed transmission charges. (P5)	It is acknowledged that the different approaches to intra-regional and inter-regional TUOS pricing will create some additional complexity and loss of transparency. However, the scope of the rule change is restricted to inter-regional charging.
	The modified LEC would be preferable to the original LEC as it is based on application of a consistent methodology. This is on the proviso that the benefits of carrying out an additional uniform national cost reflective network pricing methodology outweigh the additional administrative costs of doing so (P4)	It is anticipated that the additional administrative costs of modified load export charge (compared to LEC) will be very modest
	Consumers / stakeholders may find differences in methodology between intra and inter regional charging confusing, adding to an already complex system of calculating prescribed transmission charges. (P5)	It is acknowledged that the different approaches to intra-regional and inter-regional TUOS pricing will create some additional complexity and loss of transparency. However, the scope of the rule change is restricted to inter-regional charging.
	cost sharing represents a considerable departure in methodology from existing intra-regional methodologies, and other proposed options for inter-regional charging. There is considerable merit in having consistency between the derivation of the	Agreed. There are no substantive differences between intra-regional and inter-regional transmission that would justify such different approaches to pricing the two services.

Stakeholder	Issue	AEMC Response
	inter-regional charge and the intra-regional charge. Having two different regimes adds complexity and raises questions as to why two regimes exist. (P6)	
	The preferred option should be subject to extensive modelling over an extended time period (taking into account varying energy flow patterns between jurisdictions) before it becomes the final option. (P5)	Some modelling has been undertaken and a report published.
	transmission network service providers should not be required to negotiate / agree in isolation on any components of the methodology. Such negotiation / agreement should be carried out on a nationally consistent basis and be overseen by an independent body, such as the AER. (p2)	The common elements of the modified load export charge are set out in the second draft rule. For all other matters the AER is required to update its guideline.
	it is more important to establish some form of inter-regional transmission pricing now even if not perfect rather than wait until a 'perfect' process can be developed. Any problems with the initial regime can always be addressed in a review after a few years. (p2)	Agreed
TruEnergy	The AEMC needs to be satisfied that this approach can be implemented and that its benefits exceed its costs. We believe that before any form of new pricing regime is introduced, the AEMC needs to be satisfied that the benefits of implementing that new regime should exceed its benefits. (p5)	Since the administrative costs are expected to be very modest, the rule change is expected to generate net benefits, even if its impacts on NEM outcomes are small.
	We acknowledge that the cost sharing option would be easier to implement compared with the other options given its simplicity of design. However, in providing a simple inter-regional transmission	Agreed.

Stakeholder	Issue	AEMC Response
	charging approach under this methodology, the price signalling to consumers would be lost. In short, costs would be shared between transmission network service providers and not based on the proportionate use of the assets. (P4)	
	However, we understand that a modified load export charge - which would recover inter-regional transmission charges on a bilateral basis - has one major shortcoming. And, that is that inter regional charges can only be levied on transmission network service providers in neighbouring areas under a modified load export charge. (P3)	Agreed. The NEM-wide cost reflective network pricing method does not have this limitation, however the cost of implementing that approach would be significant.
	The inconsistent application of intra-regional TUOS in the NEM would raise serious questions regarding the efficiency of any inter-regional transmission tariff developed under a LEC (P2)	Agreed. This is why the second draft rule adopts the modified load export charge.

A.3 Submissions to modelling report

Stakeholder	Issue	AEMC response
Private Generators	Supports the introduction of an inter-regional transmission charge	Noted
	Do not support an inter-regional transmission charge based on existing transmission assets	The Commission notes that the current intra-regional transmission charging method includes existing assets. To not include these assets in the inter-regional transmission charge introduces instability in charges and an inconsistency with the basic principles of the

Stakeholder	Issue	AEMC response
		intra-regional charging approach.
	The inter-regional transmission charge should be based on the true causation of the cost in the transmission network, namely the decision to incest in a new transmission asset.	The Commission notes that the benefits that can be derived from an asset over time will change and that a cost reflective network pricing based approach utilised in the intra-regional transmission charge already changes to reflect use of the assets rather than the basis on which they were constructed. The Commission is of the view that the inter-regional transmission charge should take into account the basis on which intra-regional transmission charges are determined. A more fundamental review of transmission charging is more appropriate to a broader review, such as the TFR..
	Any decision to make a network investment will lead to an inter-regional transmission charge should be reviewed by independent authority such as the AER	The AEMC note that the transmission network service providers are subject to the RIT-T regardless of whether the cost of that investment will be recovered intra-regionally or through an inter-regional transmission charge.
	Any inter-regional transmission charge should be on-going and stable unless and until a network planning decision within the region re-allocates part or all of the relevant network capability.	Stability of charges is just one relevant factor for consideration. The other aspects of the AEMC's assessment framework are outline in section 5 of this document.
	The inter-regional transmission charge should be recovered through the non-locational charges.	Recovering the charges through the locational component of the intra-regional transmission charging method is more consistent with using the locational component of TUOS in the calculation of the inter-regional transmission charge.
	The short run marginal costs of transmission are not directly met by transmission network service	All transmission network service providers costs are recovered through their pricing method. The

Stakeholder	Issue	AEMC response
	providers, are uncertain and often perverse in their impact on a transmission network service provider, and we therefore contend that no attempt should be made to include them in an inter-regional transmission charge.	inter-regional transmission charge seeks to extend this method to cover inter-regional transmission charge. It does not specifically seek to address or separate the issue into short-run or long run marginal costs.
Grid Australia	Limited opportunities for engagement in the modelling itself.	The AEMC notes that most transmission network service providers were contacted at least once in relation to the data collections process. Further, a sample set of results were provided to transmission network service providers for comment consistent with the AEMC's communication with them. The AEMC's consultant is known to all transmission network service providers as he is the author of the pricing model they use. The transmission network service providers were informed of the basis on which the modelling was to be undertaken. Despite being aware that modelling was being undertaken no attempt was made by transmission network service providers to seek further engagement with the AEMC or the AEMC's consultant beyond that engagement initiated by the AEMC.
	Agrees that for inter-regional transmission charge to be calculated at a regional level a consistent method for allocating charges between adjacent regions is required. This could be a consistent pricing method which could be overlaid on the existing arrangements or a consistent pricing method for all transmission network service providers in the NEM as proposed in the TFR.	Noted
	The modified cost reflective network pricing method results used for the reports modelling of modified	The AEMC choose to pursue the standard cost reflective network pricing for the modified load

Stakeholder	Issue	AEMC response
	load export charge provides limited insight into the application of the modified cost reflective network pricing in the rules. Modelling should give an indication of the relative charges at the extremities of the network under a standard or modified approach.	export charge because of the significantly lower implementation costs. Grid Australia's observations have been passed on for consideration as part of the TFR.
	Should the Commission pursue a consistent national pricing regime under the TFR, a national approach to replacement cost valuation of the networks would be required.	Grid Australia's observations have been passed on for consideration as part of the TFR
	The use of 10 peak trading intervals is not supported by Grid Australia as it is unlikely to reveal the circumstances under which augmentation of network elements would contemplated as required under the rules.	Noted. The AEMC discusses the selection of measurement intervals in section 13.2 .
	Grid Australia understands the intent of this variation was to determine the flow on effects of a new major interconnector asset on charges to adjacent regions. A more robust method would involve identifying an interconnector asset in each region and inflating its value.	New assets only was selected to be modelled reflecting concerns raised by some stakeholders that the inter-regional transmission charge should not apply to existing assets. The AEMC believed that it was appropriate to conduct analysis on an approach reflecting new assets only.
	Grid Australia supports the use of capacity mode in conjunction with the full year of trading intervals. It is understood that the use of energy mode for large sample sizes tends to diminish the cost reflectivity of the method.	Agreed. The analysis of capacity or energy mode is outlined in section 13.3.
	Grid Australia is concerned that the AEMC has characterised the quality of the load data provided as poor. It was expected that the data acceptance	The AEMC notes that most transmission network service providers were contacted at least once in relation to the data collections process. Further, a

Stakeholder	Issue	AEMC response
	process would involve a high degree of collaboration between transmission network service providers and the consultant. It was not apparent that all issues identified in section 8 of the report were drawn to the attention of transmission network service providers.	sample set of results were provided to transmission network service providers for comment consistent with the AEMC's communication with them. The AEMC's consultant is known to all transmission network service providers as he is the author of the pricing model they use. The transmission network service providers were informed of the basis on which the modelling was to be undertaken. Despite being aware that modelling was being undertaken no attempt was made by transmission network service providers to seek further engagement with the AEMC or the AEMC's consultant beyond that engagement initiated by the AEMC. The AEMC attempted to engage with transmission network service providers where data issues were identified. It was not the AEMC's intention to keep data validation and correction issues from transmission network service providers.
	Alignment of cost data with AEMO network model may significantly complicate the cost allocation process.	The AEMC is not requiring this as part of the inter-regional transmission charge second draft rule change.
	An inter-regional transmission charge should only be progressed only if there is no decision to implement national pricing under the TFR in the near term.	As the TFR is a review rather than a rule change any changes to the rules would be dependent on a rule change request being received and the AEMC undertaking a review of the rule change request. The timing and outcome of either of these aspects are uncertain. The Commission has determined the introduction of an inter-regional transmission charge is consistent with the NEO and second draft rule proposes the commencement of operation of the rule on 1 July 2014..

Stakeholder	Issue	AEMC response
Energy Australia	The NEM wide cost reflective network pricing was more likely to support the NEO.	The Commission has determined not to introduce a NEM wide cost reflective network pricing because the current institutional arrangements are such that no independent organisation currently possesses the skill set to immediately be able to undertake responsibility for calculating the NEM wide cost reflective network pricing.
Major Energy Users	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.	Any pricing method for transmission charges will have an indirect impact on the spot market given all participants in that market pays TUOS. It is the AEMC's position that the current arrangements are more distorting in that they do not align costs and benefits for the use of the transmission network if the beneficiary is in a different region to the transmission network service provider incurring the cost.
	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.	The inter-regional transmission charge is about the recovery of cost that are incurred. The MEU 's comment seems more relevant to the decision on whether to augment the network rather than recover a cost that has already been incurred. The process for investment in transmission network service providers is beyond the scope of this rule change.
	consumers 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.	The introduction of the inter-regional transmission charge improves prices signals as it more accurately reflects the usage of the network.
	Reliability is improved by interconnection.	Noted. However, in introducing an inter-regional

Stakeholder	Issue	AEMC response
		transmission charge the Commission had to consider costs of implementing a new arrangement as well as the benefits that would be derived from doing so. Trying to account for reliability increases subjectivity and complexity of any calculation method. The AEMC's assessment framework is outlined in section 5
	Where there are two interconnections the actuality of flows can be perverse, raising complexities that impinge directly on the issue of reliability and generator locations.	The modelling results show that some approaches to the inter-regional transmission charge, including the Commissions preferred approach, are stable across time.
	The inter-regional charge is a cost to consumers which have little ability to manage or mitigate the risk and costs.	The inter-regional transmission charge does not change the revenue for transmission network service providers. So the inter-regional transmission charge is not a cost to consumers as a group. It will increase costs to some consumers while lowering costs to other consumers based on their location and usage. Most importantly it does so in a way that better reflects the benefit that consumers are currently deriving than the current arrangements.
	Options 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 that the approach used in another region.	The AEMC has consulted broadly on this rule change. Stakeholders have overwhelming endorsed an approach to produce consistency across methodologies.
	Because the inter-regional charge is levied purely as a transmission charge and does not reflect the delivered cost to consumer, competitive neutrality between all parts of the supply chain is put at risk.	Improving price reflectivity improves the signals to all aspects of the market.

Stakeholder	Issue	AEMC response
	Implementing a load export charge through transmission costs that generators do not see, less efficient location signals are provided to generators.	The current arrangements do not provide direct locational signals to generators. The introduction of an inter-regional transmission charge does not change these arrangements. Therefore, the Commission strongly disagrees with the MEU's suggestion that the inter-regional transmission charge will produce less efficient location signals for generators.
	For price signals to provide the outcome sough, there must be consistency in bother their development method and the actual prices.	Agreed. Transparency of operation and outcome are part of the AEMC's assessment framework.
	An inter-regional charge needs to reflect basic actualities.	The inter-regional transmission charge is trued up for differences between actual and estimated flows meaning that it reflects the actuality of the costs incurred by transmission network service providers and the flows on their network.
	Perverse and inequitable outcomes are still likely even with the new approaches to this inter--regional charge	The AEMC requests that the MEU provides some evidence to support this statement.
	The variability in costs is also a major concern in regions that have a large degree of weather risk.	Regulatory stability and outcome transparency are both part of the AEMC's assessment framework. These assessment framework is outlined in section 5
	Without extensive modelling and analysis it is difficult to fully evaluate approaches.	The AEMC has published the results of all the modelling that it has undertaken, this shows the extent of inter-regional transmission charges. Stakeholder's should be able to evaluate the different options under consideration by the AEMC.

Stakeholder	Issue	AEMC response
	The MEU questions the benefits in the short or long term given the issues and complexities.	The AEMC's basis for its determination that the preferable draft rule better meets the NEO are set out in the second draft determination.
	It is not made clear as to the basis for the modelling.	The basis for the modelling is clearly spelt out in Rolib Pty Ltd's report on the AEMC website.
	The modelling report states that the inter-regional transmission charge should be based on capacity transfer. Yet it does not make it clear as to what capacities have been used.	The report refers to utilising the capacity (or peak) approach to element use
	This assessment makes setting a LEC somewhat problematical should the charge be based on the annual usage in a particular year or should they be based on the cost of the assets that allow the flows as and when needed?	It is to get stakeholder feedback on this and other issues in relation to the calculation of the inter-regional transmission charge that the AEMC has published the discussion paper, modelling report and this second draft determination.
	It is often the intra-regional transmission capacity of a region that determines its ability to import power from another region.	This would then be reflected in the level of the inter-regional transmission charge from other regions to that region. If it is a result of insufficient transmission capacity then that would be expected to be resolved by a transmission network service provider seeking to augment the network and the application of the RIT-T.
	The modelling carried out reflects some additional identified issues that need addressing before the results of the modelling are robust enough to be used for developing the basis of the inter-regional transmission charge.	A lack of robustness to the modelling is not a view shared by either the AEMC or its consultant.
	One of the concerns the MEU has with the modified	Broader consideration of pricing methodologies is

Stakeholder	Issue	AEMC response
	load export charge and LEC is that the design of pricing used in the Rules and implemented by TPrice, already have a number of shortcomings.	beyond the scope of this rule change. Fundamental changes for a method that is overlaid on the intra-regional charging method would introduce additional cost for an uncertain level of benefit.
	Except for Victoria inter-regional charging would be from one region to another.	The AEMC notes that NSW also has two neighbouring regions. In their additional analysis in this section the MEU appears to be confusing the contractual flows with utilisation of the network.

A.4 Submissions to second draft determination

Stakeholder	Issue	AEMC response
MEU	Considers that the Commission has not provided a holistic treatment of development of an inter-regional transmission charge as required under the NEO. It focuses on transmission without consideration of the wholesale market. They argue that when the cost of modified load export charge is added to cost of importing generation, it may not be lower than cost of local generation. modified load export charge would then undermine the NEO. They provide a numerical example to demonstrate this	This would imply that either the prices of imported generation or transmission costs are somehow inefficient. A competitive NEM ensures that energy flows between regions is normally efficient (that is from areas with low cost generation to areas of higher cost generation). In addition, the RIT-T requires that inter-regional transmission is only built if it is efficient from an overall market perspective (it is not just region based). The example set out by MEU assumed the bids of local generation would be the same in the absence of inter-regional capability. This is unlikely to be the case. Without inter-regional capability energy bids in the importing region (SA in the MEU example) would likely be higher. One of the benefits of

Stakeholder	Issue	AEMC response
		inter-regional transmission capability is that provides competitive discipline on the bidding behaviour of generators in the importing region
	Consumers cannot influence, or respond to modified load export charge costs because Inter-regional flows caused by pricing of generators over which consumers have no control. The efficiency properties of the modified load export charge are therefore negligible.	The modified load export charge quantum will be related to the degree to which the consumer takes its energy from interconnection related infrastructure. This in turn is determined by the level of utilisation and proximity to such infrastructure and location of nearby generation capacity. New consumers can change their location to lower these costs, while it is true that for existing consumers such costs are largely sunk. However, there should be some capacity for existing consumers to lower their peak utilisation rates to elicit lower future transmission charges. Further, we argue that allocating costs in line with benefits (regardless of whether they are existing or new consumers) more broadly underpins confidence in regulatory arrangements (For example, opposition to RIT-T investments would be less) and supports dynamic efficiency in complementary markets.
	MEU considers that because generators do not face transmission charges, in effect consumers will see a higher modified load export charge due to the poor locational decisions of generators, since modified load export charge will be in part related to the distance between generation and load	The issue of generator locational charges is being addressed in the TFR. Even in the absence of a generator locational charge, large consumers will have incentives to seek the best deal, therefore all else equal, as a new consumer they will seek to locate

Stakeholder	Issue	AEMC response
		in an area where their transmission charges are likely to be lower, that is, in closer proximity to generation capacity. However, the AEMC agrees that existing consumers cannot respond to the locational decisions of new generators.
	Considers that if assets in exporting region are sized to enable a greater inter-regional transfer than importing region is capable of receiving, then importing region consumers may end up paying too much for transmission assets in exporting region, particularly where there is excess capacity in exporting region	
	Considers modified load export charge should be based on maximum demand not volume and system peak approach rather than element peak approach.	Commission has set out its reasons for why it prefers an element peak combined with cost reflective network pricing approach in the body of this final determination.
	MEU modelling shows there is one net importer of power but is paid by the exporter to take this power. Even if there is no net inter-regional flow one region will still have to make a payment to the other region.	The modified load export charge is based on a capacity approach, which in effect seeks to measure the maximum amount of inter-regional capacity used by each region, rather than frequency of imports per se. A capacity approach better recognises that the key benefits transmission delivers are competition from generators in neighbouring regions and reliability (sharing of energy reserves). These benefits are related more to peak capacity rather than energy flows (these benefits would be there even without any flows).
Grid Australia	Grid Australia is broadly supportive modified load export charge but notes some ambiguities in the proposed drafting of the rule and sets	Noted and addressed in final rule

Stakeholder	Issue	AEMC response
	out one issue of substance.	
	The proposed methodology does not in fact pass through the charge based on the consumer's proportionate use of inter-regional assets (or a proxy of those assets). Rather, the modified load export charge would be allocated on the basis of proportionate use of intra-regional assets, considerably muting the signalling properties of the modified load export charge	Noted and addressed in body of Final report
	Grid Australia proposes an alternative methodology for recovery of inter-regional costs from consumers. The modified load export charge would need to be converted to an equivalent asset cost applied to a proxy asset(s) on the border(s) in order to be allocated to consumers	Noted and addressed in body of final report
	Believe it is not possible to meet timing of 1 July 2014. Proposes AEMC defers implementation of the modified load export charge until subsequent transmission pricing period, beginning 1 July 2015.	Noted and addressed in body of final report
Tasmanian Government (OEPC)	Supports modified load export charge	
Private generators	Using network flows as a surrogate to the identification of the beneficiaries leaves the consumers unsure from one year to the next whether they will have deemed to have benefited, what they will be charged and whether they should support future investment	While the modified load export charge approach will deliver less stability in charging, we consider the charging will be more reflective of costs incurred and benefits delivered relative to the private generator's cost sharing approach. We discuss this in more detail in the body of the report.
	Aligning the pricing of new assets with existing assets leads to pricing distortion, modified load export charge method does not	It is important to note that the RIT-T is the principle route by which new investment is justified in the NEM, and was developed to

Stakeholder	Issue	AEMC response
	provide an appropriate signal for new investment	be a forward looking approach to assessing the costs and benefits of investment. We set out in the main body of the report why we consider the modified load export charge, in combination with the RIT-T, provides the best option for addressing our assessment criteria.
	Notes important interaction with the TFR. If interconnector capacity increases due to a generator purchasing firm access, and money recovered from consumers in the importing region should be taken into account in deciding what payment the firm generator should contribute.	While it is yet to be decided whether OFA will be introduced in the NEM. As a matter of principle, under OFA generators will secure a property right over any capacity they fund so therefore receipt of any further regulated transmission charges from consumers would be inappropriate..
Energy Australia	Supports modified load export charge	
InterGen	Supports modified load export charge but considers it needs to be extended beyond prescribed services to negotiated and unregulated services. The test should be not whether asset is regulated or not, but whether it contributes to inter-regional flows. Owners of non-regulated assets should be able to recover some of the costs of inter-regional benefits delivered by the asset.	This issue is addressed in the body of the final report. In summary, the AEMC considers it is inappropriate to have the costs of a commercially negotiated assets recovered as a regulated charge from consumers. The cost recovery provisions in the rules are different for negotiated and prescribed services for important reasons; because provision of negotiated services are open to some level of competition while those for prescribed services are not (due to economies of scale, externalities etc.).
SA government	Considers energy approach better than capacity approach in allocation of costs; which would have the effect of allocating charges on the degree of imports. Capacity approach may not	An modified load export charge based on capacity approach provides for more stable charge and better recognises the benefits

Stakeholder	Issue	AEMC response
	adequately recognise the export of wind generation from south Australia. Concern that SA will still be charged an inter-regional charge despite being a net exporter of energy.	transmission brings in terms of competition and reliability which are independent of flows (for example peak generation capacity in VIC will support reliability outcomes in SA as well as act as a competitive constraint on the bidding behaviour of gas fired generation capacity in SA).
AEMO	Do not support peak element approach or use of cost reflective network pricing	Arguments for why we support the modified load export charge option is set out in body of the document
	Support NEM wide methodology administered by central authority	Arguments for why we support the modified load export charge option is set out in body of the document

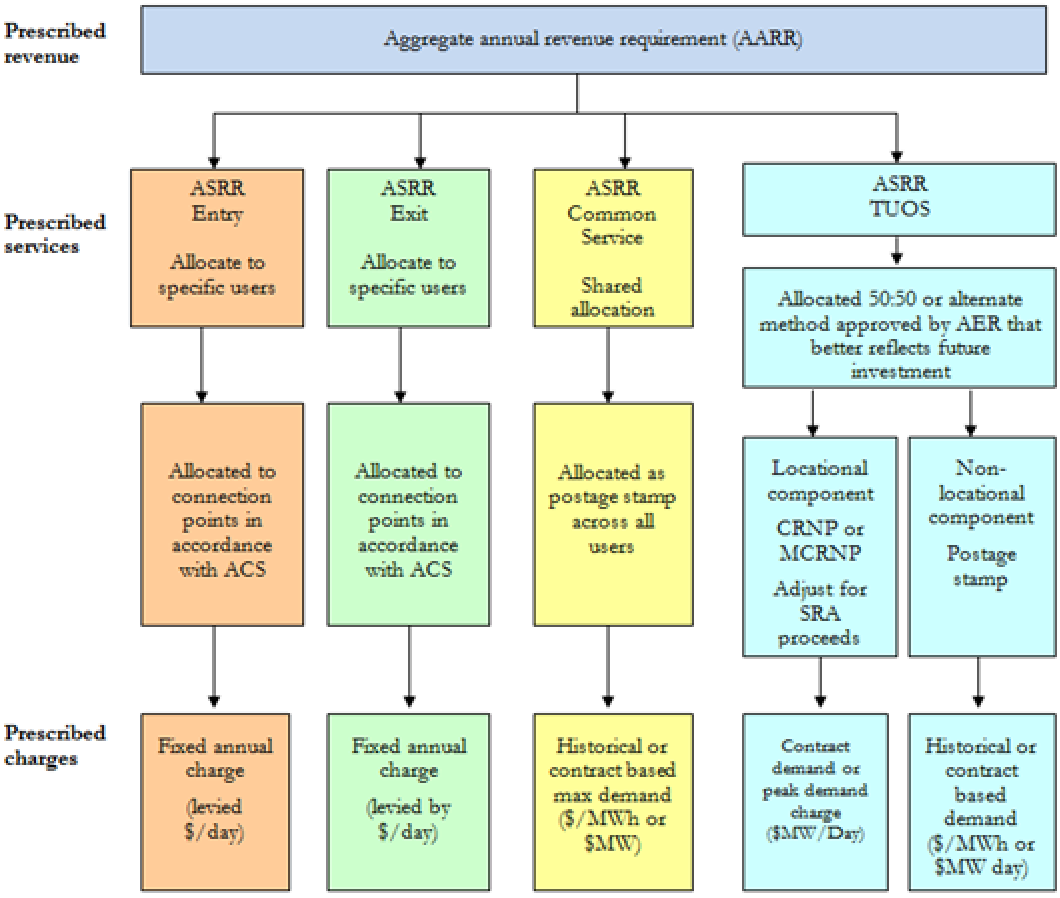
B Current cost allocation arrangements

The costs of the prescribed transmission services are recovered based on a Maximum Allowed Revenue (MAR) set every 5 years by the Australian Energy Regulator (AER). The MAR is adjusted to create an Aggregate Annual Revue Requirement (AARR) for transmission companies. This is the revenue that relates to the costs of prescribed transmission services only ('negotiated' and unregulated services are excluded).

There are four categories of regulated or 'prescribed' transmission services:

- Entry services.
- Exit services.
- Transmission common services.
- Transmission use of system services (TUOS).

The process governing cost allocation, revenue recovery and pricing is shown diagrammatically below



Prescribed common transmission services provide equivalent benefits to all transmission consumers on the network without any differentiation based on their location. Examples of assets that are used to provide these services include a transmission network service provider's control buildings, protection systems, and communication systems.

Prescribed TUOS services' incur different costs for transmission consumers depending on their location; for example, the level of transmission infrastructure required will vary depending on where consumers are situated relative to generation capacity. This generally constitutes the majority of the prescribed transmission services costs. For the purposes of developing an inter-regional transmission charge, prescribed entry and prescribed exit services are not considered.

The AARR is converted into an Annual Service Revenue Requirement (ASRR) for each category of services, based on the costs of those services relative to overall costs (these costs are based on optimised replacement costs). More formally, the ASRR is recovered on the basis of the Attributable Cost Share (ACS) for each category of service (i.e. prescribed entry, prescribed exit service, prescribed common transmission and prescribed TUOS services). The ACS is the ratio of costs of the transmission system assets directly attributable to the provision of that category of service to the total costs of all of the transmission network service providers' transmission assets directly attributable to the provision of prescribed transmission services.

For costs related to the provision of prescribed TUOS services, its ASRR is split into locational and non-locational components by 50:50 (except where a modified cost reflective network pricing is used). Non-locational cost recovery means costs are recovered using a postage stamp; a charge that does not vary by location or the level of utilisation of assets, while locational costs are recovered based on Cost reflective network pricing, as explained in Section 4.1

Converting transmission costs into prices

Application of the cost reflective network pricing (and its modified form) results in a lump sum dollar amount to be recovered at each transmission connection point.

The AER permits a range of pricing structures to be implemented to recover this lump sum amount, which depend on whether locational or non-locational costs are being recovered[70].

Locational pricing

The prescribed non-locational TUOS service component is adjusted for over/under recovery and settlement residue auction (SRAs) proceeds. The locational price is then derived by either of the following:

- The current contract agreed maximum demand as negotiated in a connection agreement or the transmission consumer's maximum demand in the previous 12 months if the consumer exceeds the agreed demand, expressed as $/MW/day; or

- The average of the transmission consumer's half-hourly maximum demand recorded at a connection point on the 10 weekdays when system demand was highest between the hours of 11:00 and 19:00 in the local time zone during the previous 12 months, expressed as $/MW/day.

70 These are set out in the AER's pricing methodology guidelines for transmission network service providers, available on the AER website

A 2 per cent tolerance requirement applies to the prescribed locational TUOS service prices.[71] This is a smoothing factor as the Rules require that the prices must not change by more than 2 per cent per annum at connection points relative to the load weighted average prescribed locational TUOS service price for the region

The balance of any revenue shortfall or over recovery resulting from these price caps is recovered or offset as appropriate by adjusting prescribed non-locational TUOS service prices and charges.

Non-locational pricing

For the prescribed non-locational TUOS service component, its ASRR is smeared across all connection points (postage stamp). This is based on historic energy consumption at the connection point.

The charge for this component can be either:

- Historical energy based ($/MWh); or
- Contract agreed maximum demand ($/MW)

The historical energy based charge is derived from the historical energy based price multiplied by the metered energy at the connection point in the equivalent billing period during previous financial year.

Where contract agreed maximum demand is used, the contract agreed maximum demand price should be multiplied by the maximum demand for the connection point in that financial year and then divided by the number of billing periods in the financial year.

71 An exception to the 2% tolerance requirement for prescribed locational TUOS service prices is where there is a material change in load at the connection point that is equivalent to the creation of a new connection point.