Public Interest Advocacy Centre

Transmission charging rule change request

23 February 2024

Public Interest Advocacy Centre
ABN 77 002 773 524
www.piac.asn.au

Gadigal Country
Level 5, 175 Liverpool St
Sydney NSW 2000
Phone +61 2 8898 6500
Fax +61 2 8898 6555

About the Public Interest Advocacy Centre

The Public Interest Advocacy Centre (PIAC) is leading social justice law and policy centre. Established in 1982, we are an independent, non-profit organisation that works with people and communities who are marginalised and facing disadvantage.

PIAC builds a fairer, stronger society by helping to change laws, policies and practices that cause injustice and inequality. Our work combines:

- legal advice and representation, specialising in test cases and strategic casework;
- research, analysis and policy development; and
- advocacy for systems change and public interest outcomes.

Energy and Water Consumers' Advocacy Program

The Energy and Water Consumers' Advocacy Program works for better regulatory and policy outcomes so people's needs are met by clean, resilient and efficient energy and water systems. We ensure consumer protections and assistance limit disadvantage, and people can make meaningful choices in effective markets without experiencing detriment if they cannot participate. PIAC receives input from a community-based reference group whose members include:

- Affiliated Residential Park Residents Association NSW;
- Anglicare;
- Combined Pensioners and Superannuants Association of NSW;
- Energy and Water Ombudsman NSW;
- Ethnic Communities Council NSW;
- Financial Counsellors Association of NSW;
- NSW Council of Social Service;
- Physical Disability Council of NSW;
- St Vincent de Paul Society of NSW;
- Salvation Army;
- Tenants Union NSW; and
- The Sydney Alliance.

Contact

Michael Lynch
Public Interest Advocacy Centre
Level 5, 175 Liverpool St
Sydney NSW 2000

T: 0404560386
E: mlynch@piac.asn.au

Website: www.piac.asn.au

Public Interest Advocacy Centre

@PIACnews

The Public Interest Advocacy Centre office is located on the land of the Gadigal of the Eora Nation.

Contents

1. Summary

This rule change request proposes a change in the allocation of costs for large scale strategic transmission projects. PIAC proposes that costs are allocated according to a beneficiary pays principle. Specifically, we seek to amend the means by which transmission costs are recovered by transmission network service providers (TNSP) from consumers in other National Energy Market (NEM) regions. The current rules are not appropriate for the large interconnectors, identified as strategically significant by the Australian Energy Market Operator (AEMO). The current arrangements

- place an arbitrary limit on the amount of costs that can be recovered from extra-regional consumers;
- place an arbitrary limit on the consumers who can be involved (those in adjoining regions to the transmission service provider, rather than any consumers benefitting from the asset); and
- base the cost allocation on an inappropriate metric: peak demand flows.

We propose basing cost allocation on the value of energy flows, or the value of services transmitted, as this enables the beneficiary pays principle to be implemented more meaningfully.

In this rule change request we provide three possible solutions to the identified problem, each of which entails adjustments to the existing mechanisms for cost recovery.

2. Introduction

Large scale interconnectors between two or more NEM regions are being built by TNSPs as part of the ongoing energy transition. AEMO has approved the construction of these strategic transmission projects as part of the Integrated System Plan (ISP) process, intended to optimise investment in the NEM. These connectors will, among other benefits, allow for renewably generated electricity to be transferred from one region to another.

Traditionally the cost of building transmission infrastructure is borne by customers connected within a single region. Previously this meant that when a transmission line straddled two regions, each TNSP's costs for building the line were normally covered only by the customers in its region. In 2013 the AEMC approved an interregional pricing rule change. This introduced the Modified Load Export Charge (MLEC) which commenced in 2015. The MLEC is a methodology by which some, but not all, of a TNSPs costs for building interconnectors can be recovered from customers connected to the transmission network of a neighbouring TNSP to which electricity flows.

Notwithstanding the introduction of the MLEC, a large amount of TNSPs' costs for building interconnectors continues to be borne by customers within their own region, while customers in other regions may be the main beneficiaries of an interconnector. This is problematic as costs are not borne fairly between beneficiaries.

It is now ten years since the AEMC last addressed the issue of interregional charging. In this time the scale and cost of interconnectors has magnified. These interconnectors are now assessed to have NEM-wide benefits and are built once they have been approved by AEMO as part of the ISP process. As a consequence there is less need for market incentives to encourage such investments.

Recognising that interconnectors built as ISP projects provide NEM-wide benefits, and are of a scale and cost unlike traditional transmission investments, in November 2019 Energy Ministers tasked the ESB to review their fair cost allocation. The Australian Energy Market Commission (AEMC) also identified in 2020 that the current framework may not be fit for purpose for large transmission projects.

In October 2023, a rule change request was submitted by the federal Minister for Climate Change and Energy, Chris Bowen, the Victorian Minister for Energy, Lily D'Ambrosio, and the Tasmanian Minister for Energy and Renewables, Nick Duigan seeking to add flexibility to the cost allocation framework for interconnectors.

PIAC proposes that the rules on interregional charging are reconsidered in respect of large-scale interconnectors approved by the ISP process. This rule change proposal relates to how costs of strategic transmission projects are recovered through transmission pricing.

PIAC is not proposing changes to the way in which a TNSP's revenue allowances are determined by the Australian Energy Regulator (AER) for these projects.

Three potential rule change solutions are proposed.

The existing cost allocation rules, such as those setting out the Modified Load Export Charge (MLEC), would remain in place for non-ISP projects.

3. Description of the rule being proposed

PIAC requests the AEMC make changes to the transmission pricing rules in the National Electricity Rules (NER) that better promote the long-term interests of consumers than those in the current NER.

The changes proposed in this request improve the ability for the costs of strategic transmission projects to be recovered from the beneficiaries of that investment.

Strategic transmission projects are those identified as being on the optimal development path in AEMO's ISP, as these have a significant effect on national transmission flow paths and are modelled to deliver benefits across multiple NEM regions, not just the regions the project is physically located in.

Efficient investment will be more likely to proceed where consumers that benefit from that investment face the costs. As such, a 'beneficiary pays' approach to funding strategic transmission projects is more likely to contribute to achieving the National Electricity Objective (NEO).

PIAC has developed three potential solutions that each improve the allocation of costs for strategic transmission projects compared to the current arrangements:

- Solution 1 – fixing up front the proportion of revenue to be recovered for a strategic transmission project from customers in each region, based on the forecast beneficiaries of the investment.
- Solution 2 – revenue for strategic transmission projects would be recovered proportionally from all NEM customers based on consumption, with calculations and payment flows coordinated by AEMO.
- Solution 3 – amending the inter-regional transmission charging framework such that a greater proportion of costs can be recovered from beneficiary consumers in other regions. This would also involve charges which reflect the value, rather than volume, of flows.

These proposed solutions are not mutually exclusive, and elements from one or more of them could be adopted.

4. Nature and scope of issue concerning the existing rules

4.1 Context

The NEM is in the process of decarbonising, replacing large-scale fossil fuel generation with generation sourced from renewables. This is placing significant strain on existing transmission infrastructure, which was built primarily to transport electricity from a relatively small number of large generators, co-located with the fossil fuel sources, to load centres.

There is an influx of renewables into the NEM seeking to locate in areas without existing strong transmission connections. More generation is required to ensure that demand continues to be met as fossil fuel generators retire. Further, renewable generation is being curtailed as a result of network congestion, leading to higher cost generation being dispatched in its place. A significant amount of new transmission investment is required to connect this new generation, both within and between jurisdictions, and ensure it can efficiently access the market.

Recognising the challenges of the task, the Independent Review into the Future Security of the National Electricity Market (the 'Finkel Review') recommended a more strategic approach to transmission planning, including the development of an integrated grid plan to be led by AEMO in consultation with TNSPs and other relevant stakeholders.[1] AEMO developed its first ISP in 2018.

The Energy Security Board (ESB) was tasked with developing an ISP Action Plan to determine how the projects identified in the ISP should be delivered and/or progressed. The ESB recommended new Rules, implemented in March 2020, that expanded AEMO's National Transmission Planner role by replacing the National Transmission Network Development Plan –

[1] Department of Energy, Science, Energy and Resources, 'Independent Review into the Future Security of the National Electricity Market: Blueprint for the Future' (Final Report, June 2017), 124.

previously developed by AEMO based largely on input from jurisdictional planning bodies in each jurisdiction – with the ISP.

Unlike TNSPs whose planning function is focused on their own jurisdiction, the ISP takes a NEM-wide perspective to planning transmission investment. In doing so, and subject to consultation, AEMO is able to identify the mixes of transmission investments that are most likely to optimise consumer benefits across the NEM (the optimal development path), noting that significant uncertainty about how the market will develop, including future transmission flows, remains.

In its most recent draft ISP, AEMO has identified three major transmission projects as actionable under the optimal development path: HumeLink, Marinus Link and VNI West.[2] This means that TNSPs are required to publish a Regulatory Investment Test for Transmission (RIT-T) Project Assessment Draft Report (PADR) within a specified time and the first stage of the RIT-T is replaced with AEMO's analysis and consultation on the ISP.

In addition to these, Project EnergyConnect (PEC), is an actionable ISP project that is categorised as 'committed and anticipated'. It has commenced construction and is expected to be in service by April 2024 (stage 1) and December 2024 (stage 2). We include it in the tables below to give a complete picture of the scale of investment the ISP-identified projects total.

The table below sets out the most recent estimated costs for these strategic transmission projects.

Table 1: Strategic transmission projects in the 2022 ISP

Project	Estimated cost
Project EnergyConnect[1]	\$2.3 billion
HumeLink[2]	\$4.892 billion (-5% to +12%)
Marinus Link[2]	Stage 1: \$3.8 billion (± 30%) Stage 2: \$2.7 billion (± 30%)
VNI West[2]	\$3.6 billion (± 30%)

[1] Final contingent project capex costs approved by the AER for ElectraNet and TransGrid.
[2] Estimated cost range as set out in AEMO's Draft 2024 ISP (p.57).

It is not expected that these will be the only large strategic interconnectors needed for the transition. Potential future projects can be seen in the Transmission Expansion Options Report, which informs each ISP.

4.2 Material Difference of Strategic Transmission Projects

These strategic transmission projects are materially different from the transmission projects that TNSPs commonly plan and deliver for three reasons:

[2] AEMO 'Draft 2024 ISP', 53.

- They are significantly more costly.
- They have significantly higher capacity.
- They are co-optimised as a set of projects to deliver benefits across multiple NEM regions.

4.2.1 They are significantly more costly

The actionable projects range in estimated capital cost from $2.3b to $6.5b (± 30%) each (on most recent cost estimates). This compares to total actual transmission expenditure across the five TNSPs of approximately $949m per annum ($2022) for the last eight years, as shown in Figure 1.[3]

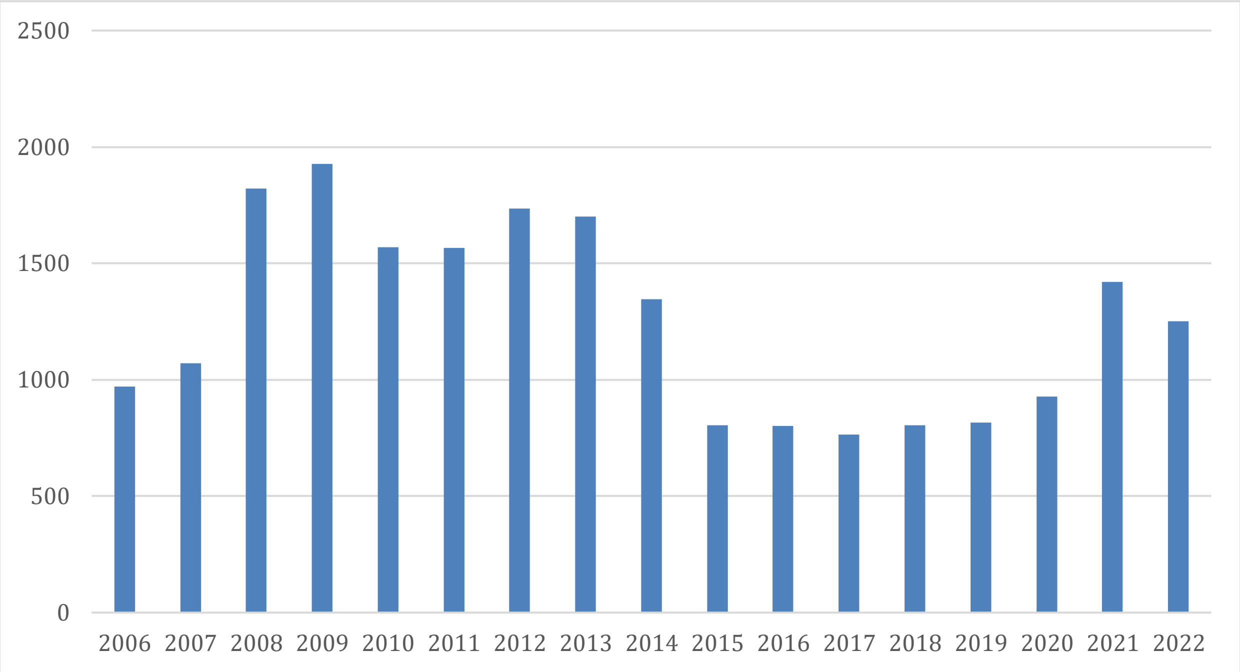

Figure 1 Actual Annual Capex – transmission total ($m 2022)

Source: AER Electricity TNSP Operational performance data 2006-2022, available here.

An alternative comparison is to look at the closing regulated asset bases (RAB) of each TNSP in 2022 compared to the maximum cost of each actionable ISP project based on AEMO's latest ISP estimates, as shown in figure 2.

These comparisons demonstrate the magnitude of the strategic transmission projects relative to the existing RABs of TNSPs.

[3] Australian Energy Regulator, 'Electricity TNSP – Operational Performance Data – 2006-2019' (Report, June 2020).

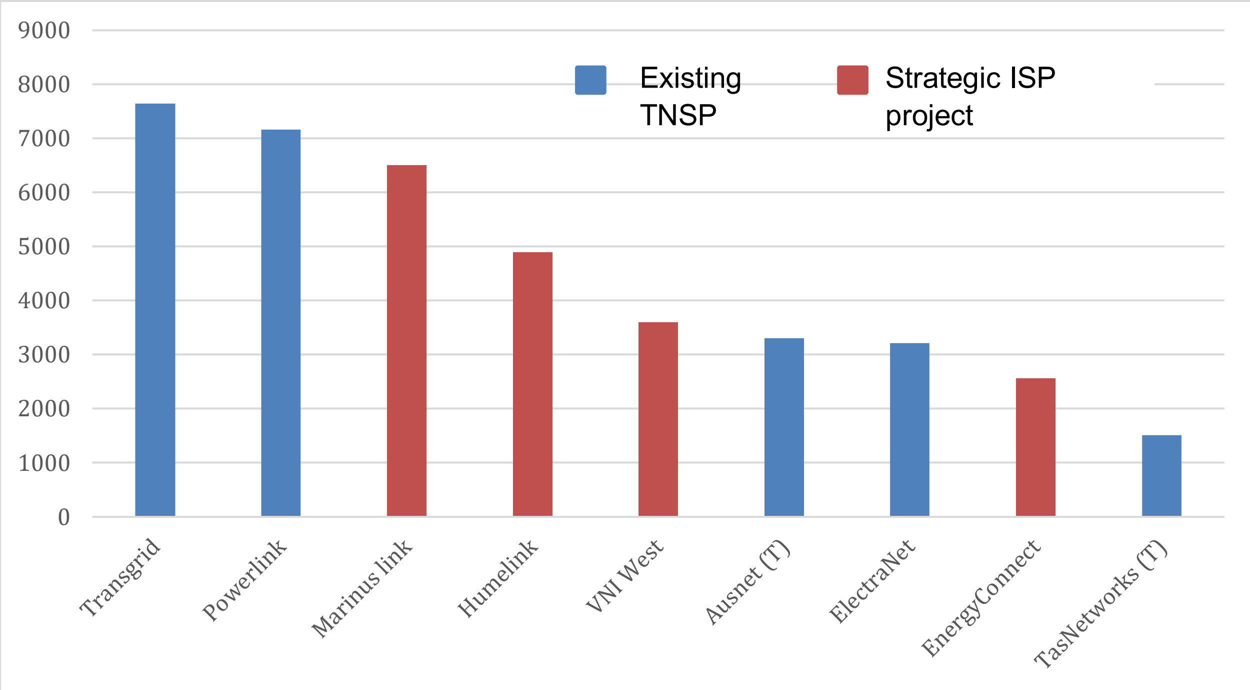

Figure 2: Closing RAB in $m 2022 and cost of strategic transmission projects

Sources: AER Electricity TNSP Operational performance data 2006-2022. Available here.
PEC figure is the summed final contingent project capex costs approved by the AER for ElectraNet and TransGrid converted to $2022.
HumeLink, Marinus and VNI West cost estimates are taken from the Draft 2024 ISP, p57, and are in $2023.

4.2.2 They have significantly higher capacity

The strategic transmission projects are expected to add significant interconnector capacity. For example, Project EnergyConnect will add 800 MW of interconnector capacity.[4] Each Marinus Link cable will add 750 MW – a total of 1,500 MW additional capacity.[5] VNI West and HumeLink are anticipated to be closer to 2000 MW.[6]

This compares to existing interconnector nominal maximum capacities of 210 MW to 1,350 MW. Only two of the six existing interconnectors have nominal maximum capabilities of more than 600 MW.[7]

[4] See Project EnergyConnect website.
[5] Marinus link Website, 'Overview'.
[6] VNI West is expected to result in additional transfer capacity of around 1,930MW from Victoria to NSW and 1,800MW in the other direction (AEMO and Transgrid 'Victoria to New South Wales Interconnector West Project Assessment Draft Report', July 2022, 9 and HumeLink is expected to increase transfer capacity between southern NSW and major load centres within NSW by approximately 2,200MW, Transgrid 'Transmission Annual Planning Report 2023, p.47.)
[7] AEMO, Interconnector Capabilities for the National Electricity Market, November 2017.

4.2.3 They are co-optimised as a set of projects to deliver benefits across multiple NEM regions

The ISP identifies transmission projects that *together* are modelled to provide an optimal development path. This modelling is conducted on a NEM-wide basis and so is designed to look at whole of system benefits across the NEM. As such, the ISP projects collectively will deliver benefits to all NEM jurisdictions. In PIAC's view, the costs of transmission investments planned on this NEM wide basis, and identified to be on the optimal development path in the ISP, should be recovered by the beneficiaries of those projects across the NEM, rather than simply based on where the relevant assets are located.

For example, PEC is a new interconnector between NSW and South Australia that was identified as an actionable project under the 2020 ISP and is now close to commission. While PEC is being constructed by TransGrid in NSW and ElectraNet in South Australia, it is also expected to deliver benefits to Victoria. A spur line will link the interconnector into Victoria, meaning that many of the benefits of the interconnector will flow into a third region.

Similarly, modelling of the distribution of gross benefits from Marinus Link suggest that multiple regions will benefit, not just Victoria and Tasmania. Under a "central" scenario, Victoria would receive 28% of the gross benefits, Tasmania would receive 6%, NSW would receive 36-38%, Queensland would receive 20-22% and South Australia would receive 7-8%.[8]

4.3 Recognition of the need for updated rules for strategic transmission projects

In recognition that the ISP projects have been identified as projects that provide NEM-wide benefits and are materially different from current transmission investments in scale and cost, Energy Ministers[9] tasked the ESB in 2019 with preparing "advice on a fair cost allocation methodology (both in theory and practice) as part of its work to action the ISP."[10]

The AEMC previously identified that the current framework may not be fit for purpose for large transmission projects,[11] and since conducted a review of transmission planning and investment,[12] but has not addressed the issue of cost recovery.

Given the scale of investment required, PIAC, like Energy Ministers, considers that it is critical the cost allocation represents an efficient as well as fair approach, prior to the costs being locked in for the next 30-40 years.

4.4 Scope of the rule change proposal

This proposed rule change relates to how costs of strategic transmission projects are recovered through transmission pricing.

In this rule change PIAC is not proposing changes to the way in which a TNSP's revenue allowances are determined by the AER for these projects.

[8] TasNetworks 'Marinus Link; How do customers benefit from Project Marinus; Summary Report', 14.
[9] At that time, operating as the COAG Energy Council.
[10] COAG Energy Council, 'Meeting Communique', 22 November 2019.
[11] AEMC 'Electricity network economic regulatory framework 2020 review' (Final report, 1 October 2020) 29.
[12] AEMC's Transmission Planning and Investment Review.

Currently the cost of transmission investments that deliver prescribed transmission services are generally recovered from transmission customers.[13] Solutions 1 and 3 of this proposed rule change would not change this general arrangement, and Solution 2 would result in costs being passed on to Market Customers.[14]

The rule change would be applied to strategic transmission projects identified by AEMO as being on the ISP's optimal development path.

4.5 Problems with the existing transmission rules

PIAC has identified several problems with the current transmission pricing framework[15] as it relates to strategic transmission projects. These problems have implications for recovering the costs of transmission investment from customers in other jurisdictions via inter-regional transmission charges. Specifically:

- There is an arbitrary limit placed on the proportion of costs that can be recovered from consumers in regions other than the geographic area of operation of the TNSP.
- There is an arbitrary limit placed on the geographic location of consumers who can be involved in cost recovery. That is, costs can only be recovered from consumers in a directly adjoining region.
- The peak demand flows metric, on which the cost allocation is based, is no longer appropriate.

4.5.1 How inter-regional costs are currently allocated

As TNSPs are responsible for providing prescribed transmission services in their own region,[16] PIAC understands that cost recovery for interconnectors is typically assigned to TNSPs on a geographic basis; i.e. the value of the assets that are located within their region. This proportion is fixed and is reflected in the annual aggregate revenue requirement (AARR).[17]

TNSPs are permitted to recover the efficient and prudent costs of providing prescribed transmission services in their region through a maximum allowed revenue determined by the AER. The maximum allowed revenue is then adjusted to determine the AARR and the AARR is allocated to each category of prescribed transmission services in accordance with their pricing methodology. The amount of AARR allocated to each category of prescribed transmission services is the annual service revenue requirement for that category (ASRR). TNSPs then

[13] There are specific exceptions to this general rule in relation to prescribed entry services and system strength services under new system strength rules commencing in late 2023 and 2024.

[14] While PIAC continues to support a model under which the risks of transmission investment in Renewable Energy Zones are not fully borne by customers, these models are also being considered under a separate process. See PIAC 'Submission Central-West Orana REZ access scheme issues paper' (Report, 7 May 2021).

[15] See in particular, NER chapter 6A. Regulation of Transmission Services, part J 'Prescribed Transmission Service – Regulation of Pricing'.

[16] The situation is slightly different in Victoria, where AEMO has responsibility for planning the transmission network, however the same issues apply.

[17] See NER chapter 6A. Regulation of Transmission Services, part J 'Prescribed Transmission Service – Regulation of Pricing'.

convert the ASRR into prices in accordance with their pricing methodology.[18] The proposed changes to transmission prices under this rule change relate to the allocation of the ASRR for prescribed Transmission Use of System (TUOS) services, being the prescribed transmission services relating to the provision of the shared network service.

However, the rules provide for an adjustment to prices to reflect benefits of transmission investment in one jurisdiction occurring in other jurisdictions. Under the current pricing framework, 50% of the AARR for prescribed TUOS services is adjusted to reflect a Modified Load Export Charge (MLEC).[19] The MLEC was introduced in 2015 to recognise that the benefits of regulated transmission investment in one region could ultimately flow into another region, whether that be from the use of intra-regional transmission assets or interconnectors. As such, the MLEC is used to recover a portion of transmission costs from customers in the adjoining region.

The Rules set out a prescribed methodology that must be applied to calculate the MLEC.[20] It is a nationally consistent approach based on the net power flows between adjacent regions over a year, requiring:

- all transmission system assets to be included;
- operating conditions in all half hour periods of the prior financial year be taken into account; and
- peak usage of transmission system elements to be used.

4.5.2 This mechanism is not appropriate for ISP-identified interconnectors

There are a number of problems for electricity consumers with this approach in the context of large transmission projects of national significance such as those contemplated under the ISP:

- The initial allocation of revenue is fixed based on geography, not beneficiaries. At an extreme, this means a situation could arise where close to 100% of an interconnector is located in Region A and the majority of benefits might flow to customers in Region B. Despite this, the TNSP in Region A is required to recover the majority of its allowed revenue for that project from customers in its region.
- The MLEC attempts to reassign costs based on beneficiaries, however this has a limited impact because only 50% of the revenue requirement for prescribed TUOS services is able to be recovered from another region. Given the scale of the ISP projects, and that they have been planned as part of an optimal development path that optimises benefits across the NEM, it is not clear that only assigning up to 50% of costs to an interconnected region meets the NEO.

  For example, under PEC, the NSW TNSP (and so NSW customers) will incur the majority

[18] See NER chapter 6A. Regulation of Transmission Services, part J 'Prescribed Transmission Service – Regulation of Pricing'.

[19] The locational component is also modified by the settlement residue auction proceeds. This rule change request does not propose to change this mechanism.

[20] NER clause 6A.29A.

of the costs (estimated to be $1.8b in capex[21] compared to $0.5 for the SA TNSP[22]), yet many of the benefits will flow to SA and Victorian customers.[23] Under the financing deal announced in September 2023 for Marinus Link, the Commonwealth will contribute (and hold equity equal to) 49%, while Tasmania will contribute 17.7% and Victoria 33.3%.[24] This is despite the expectations that Tasmanian and Victorian consumers are only expected to receive 6% and 28% of the benefits, respectively.[25]

- Further, the 50% that is recoverable from another region is based on peak demand flows not the value of those flows or the value of any other services that may be provided via those transmission assets, such as system security services. PIAC's view is that peak demand flows are not a good proxy for the value that consumers receive from transmission investments made in another location. This is increasingly likely to be the case under an interconnected system with positive and negative price events.

- Finally, the MLEC only allocates costs between two interconnected regions, not other regions that may also benefit from a transmission project. As noted above, the benefits of ISP projects are likely to extend beyond the two interconnected regions into other regions in the NEM and have been planned as part of an optimal development path that optimises benefits across the NEM.

Consequently, while an ISP project must be demonstrated to have a net market benefit consumers in order to proceed,[26] since this test is done on a NEM-wide basis, it could be the case that within a single jurisdiction the costs of the project that fall on customers in a given region could outweigh the benefits they receive.

There are a number of implications of this:

- This is not in keeping with the principle of 'beneficiary pays'. When the AEMC introduced the MLEC, 'regional beneficiaries pay' was an assessment criterion. The AEMC noted 'the allocation of transmission costs through an inter-regional charge between regions (i.e. between consumers in aggregate in each region) should broadly be commensurate with the perceived regional allocation of benefits of transmission'. The current cost allocation mechanism does not meet this test for strategic transmission projects. Efficient investment is undermined where the majority of the costs fall on a set of customers that do not receive the majority of the benefits.

- There may be circumstances where otherwise efficient investment may not proceed because the benefits of the project cannot be demonstrated to the customers that would

[21] AER, 'Final Decision: TransGrid Contingent Project, Project EnergyConnect' (May 2021) 1 (denominated in $2017-18).
[22] AER, 'Final Decision: ElectraNet Contingent Project, Project EnergyConnect' (May 2021) 1 (denominated in $2017-18).
[23] PIAC notes that when ElectraNet initiated the RIT-T process for a project that ultimately became PEC, the drivers were to reduce the cost or providing secure and reliable electricity to South Australia, facilitate the long-term transition of the energy sector across the NEM to low emission energy sources, and enhance power system security in South Australia. See AER, 'Determination: South Australian Energy Transformation RIT-T' (January 2020) 5.
[24] Marinus Link, 'Marinus Link advances under new deal', 3 September 2023.
[25] TasNetworks 'Marinus Link; How do customers benefit from Project Marinus; Summary Report', 6.
[26] Unless the investments are for reliability corrective action.

pay for it. For example, in the context of Marinus Link, TasNetworks noted '…the Tasmanian Government has stated that it will reserve its right to decide whether to proceed to construction until it is satisfied that the best interests of Tasmanian electricity customers and taxpayers will be served by the project'.[27][28]

- It may be the case that some investments proceed on the basis of an expected net benefit which does not eventuate. This scenario would imply a cohort of consumers for whom the costs outweigh the benefits. If a greater proportion of the costs are allocated to those who are expected to receive the majority of the benefits, this risk is less likely to materialise. Customers in a given region would not be expected to pay a price higher than the benefits for any other regulated energy infrastructure, or in a competitive market; the same should be true in the context of ISP projects.

Project EnergyConnect is an example where disproportionate allocation of costs relative to benefits for a jurisdiction risks a cohort of consumers seeing a net disbenefit. The net benefits of PEC were initially modelled as $924m in the Project Assessment Conclusions Report. The AER then revised the estimated net benefits down to $269m, based on interconnector costs of $1.53b.[29] The estimated interconnector costs have since been revealed to be even higher following TransGrid and ElectraNet's applications to recover revenue for PEC under the Contingent Project mechanism in the NER.[30] NSW consumers will currently pay a disproportionate amount of costs for PEC compared to the benefits they receive. If the predicted benefits do not materialise, this will mean NSW consumers face an even worse net disbenefit.

PIAC notes that, in its decision to introduce the MLEC, the AEMC considered that an inter-regional transmission charge would promote the NEO for the following reasons (among others):

- "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."[31]

The introduction of an inter-regional transmission charge may have improved cost reflectivity of prices and confidence in regulatory arrangements in the context of relatively small and limited transmission investment, as was typically the case in 2015 when the charge was introduced. However, for reasons noted above, PIAC considers that the current mechanism will not deliver these outcomes in relation to the large transmission investments expected to occur over the next decade and beyond. As such, an alternative mechanism that more efficiently allocate costs of transmission investment between regions is required.

[27] TasNetworks, 'Beneficiaries pay" pricing arrangements for new interconnectors', (Discussion Paper, February 2020) 12.
[28] PIAC notes that the Commonwealth Government subsequently provided a grant to help support the project.
[29] AER, 'Determination: South Australian Energy Transformation RIT-T' (January 2020) 6-7.
[30] See AER, 'Final Decision: TransGrid' (n 17) and AER, 'Final Decision: ElectraNet' (n 18).
[31] AEMC, 'Rule Determination: National Electricity Amendment (Inter-regional transmission charging) Rule 2013' (28 February 2013) 10.

5. Objectives for allocating costs of strategic transmission projects arrangements

PIAC considers that the NER should allocate the costs of strategic transmission projects to meet the following objectives:

- Costs for strategic transmission projects are recovered on a beneficiary-pays basis across multiple NEM jurisdictions – such that the consumers from each region pay the share of costs proportionate to the benefits they receive. This reflects the basis on which these investments have been planned and assessed by AEMO as forming part of the optimal development path in the ISP.

- Efficient investments in transmission projects are pursued, even where the benefits fall predominantly outside of the region where asset is located.

- 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.

- The regulatory framework drives major transmission investment that is in line with the long-term interests of consumers and is robust to changing circumstances (such as changes in modelled network utilisation or economic benefits).

- The regulatory framework balances delivering:
  - benefits to consumers in line with their interests and preferences, with
  - delivering fair and risk-appropriate returns for regulated network businesses.

- The regulatory framework is not inordinately complex.

- The regulatory framework provides transparency in how costs are allocated as prices for transmission services are more reflective of the actual costs incurred in providing those services.

6. Proposed rule

There are a number of ways in which the above cost allocation objectives could be addressed.

Below we outline three potential solutions: the first two introduce a new mechanism for recovering the costs of strategic transmission projects. The third amends the way inter-regional transmission charges are calculated.

While these have been presented as separate solutions, a hybrid approach combining aspects of them could be adopted.

Appendix A summarises the cost allocation and payment flow methodologies for the existing MLEC system and three proposed options for ISP projects.

All proposed options would require amendment of the rules in Chapter 6A Economic Regulation of Transmission Services. We have sought to identify those rules which will require amendment and where new rules/clauses will be necessary. We acknowledge that there may be additional and consequential rule changes needed to effect the solutions proposed here.

Non-ISP projects would continue to use the existing rules.

6.1 Solution 1 – Fixing up front the proportion of revenue to be recovered from other regions

Under this solution, the proportion of revenue to be recovered from customers in each region for a strategic transmission project would be fixed up front, based on the forecast beneficiaries of the investment.

Existing mechanisms for all projects except strategic transmission projects would remain the same; that is, they would be recovered under the current MLEC and the basis for calculating the MLEC would not change.[32]

There would be no change to the way in which a TNSP's revenue allowance is determined for strategic transmission projects and TNSPs would continue to invest in and recover revenue for transmission assets in their region.

However, for the purposes of transmission pricing (and under the pricing methodology), the allowed revenue related to ISP projects would be identified separately from allowed revenue related to other transmission investment. The revenue from strategic transmission projects would be recovered using a different process as follows:

- AEMO would identify in the ISP the distribution of costs and market benefits of each ISP project by NEM region.[33] In the project assessment conclusions report for the RIT-T for the ISP project, TNSPs would update the forecast distribution of market benefits by NEM region for their preferred option. AEMO could then be asked to confirm this forecast distribution of benefits as part of the 'feedback loop' process under clause 5.16A.5 of the NER. The forecast distribution of market benefits by NEM region would be used to allocate the costs of the relevant ISP project to jurisdictions under the pricing methodology described below.

- For the purpose of implementing the pricing methodology, the proportion of the annual revenue requirement for the project would be assigned to each jurisdiction based on the notional allocation of benefits forecast in the above process. For example: TNSP 1 and TNSP 2 invest in a major interconnector. The TNSP in jurisdiction 1 invests $1b in assets in its jurisdiction and TNSP 2 invests $200k in assets in its jurisdiction. If the RIT-T models that the benefits of a major interconnector will be split between jurisdictions 1, 2 and 3 on a 10%, 40% and 50% basis then each TNSP would need to recover costs from their customers based on that split.

---

32 Aside from adjustments to avoid double counting.

33 AEMO is already required to identify the distributional effects of projects on the optimal development path under the AER's Cost Benefit Analysis Guidelines, but this obligation may need to move to the NER level to facilitate the changes to the pricing methodology for ISP projects proposed in this rule change request.

- To facilitate efficient implementation of the new transmission charging arrangements, responsibility for calculating and invoicing all inter-regional charges, including for existing transmission investments, could be moved to AEMO, given it will require a more complex calculation and movement of funds between multiple TNSPs. Unlike solution 2, which considers an expanded role for AEMO in relation to payment flows, charges would continue to be recovered from transmission customers via TUOS charges.

- MLEC calculation for ISP projects would need to be adjusted to avoid double counting.

This solution would likely be more complex to implement than only modifying existing inter-regional charging arrangements as in Solution 3 described below. However, it would provide a more accurate allocation of costs to the anticipated beneficiaries at the time the investment decision is made. Further, AEMO is already required to model distributional effects of projects as part of the ISP process.

Under this methodology, consideration could be given to whether the initial allocation should be revisited over time. It is likely that the actual proportion of benefits accruing to customers in each region will differ from those forecast and/or the beneficiaries of the investment will change over time due to changing circumstances and new investments. While the relative cost share could be revisited periodically, it is more difficult to estimate the beneficiaries after the investment has been commissioned because after commissioning the counterfactual of no investment becomes difficult to define. Further, revisiting the allocation would be inconsistent with how costs are currently recovered for existing transmission projects.

Alternatively, the model could include an option to move over time to an allocation of costs for ISP projects based on postage stamp pricing. For example, charges could be based on a usage (MWh) basis as a proxy for allocating costs to beneficiaries, implemented on a rolling basis such that the percentage of costs that are 'postage stamped' increases over time.

Consideration will also need to be given to whether all ISP investments should be subject to this approach. For example, it may be complex to apply this methodology to ISP projects that involve minor upgrades to existing interconnectors (for example, VNI minor), where the costs of existing assets are already being recovered under the existing pricing methodology. Where it is not straightforward to distinguish between existing and new interconnector assets, these investments may need to be excluded from the proposed revenue recovery arrangements and remain subject to existing inter-regional pricing arrangements.[34]

6.2 Solution 2 – AEMO recovers the cost of ISP projects from all NEM customers

Many elements of this solution are the same as for Solution 1, including:

- Existing mechanisms for all projects, except ISP projects, would remain the same.

[34] Alternatively, the costs associated with the entire asset, meaning the new costs associated with the upgrade and the residual costs associated with the legacy elements, could be transferred to the new pricing methodology. This may be preferable as it promotes the benefits of the beneficiary pays principle, though we anticipate that such an arrangement would be viewed as unfavourable due to retroactively changing the value proposition of investments already made from different stakeholders' perspectives.

- There would be no change to the way in which a TNSP's revenue allowance is determined for strategic transmission investments.

- TNSPs would continue to invest in and recover revenue for their transmission assets.

- For the purposes of transmission pricing (and the pricing methodology), the allowed revenue related to ISP projects would be identified separately from allowed revenue related to other transmission investment.

The ISP project revenue would be recovered using a different process and methodology for recovering costs. There are two main differences to the current arrangements.

First, AEMO would be responsible for recovering the revenues for ISP projects via participant fees. Participant fees are charged to registered participants so that AEMO can recover its budgeted revenue requirements for performing its electricity functions.[35] \

TNSPs would inform AEMO of their annual revenue requirement for ISP projects. AEMO would factor these costs into its own annual budget, including any costs associated with carrying out this function, then recover these costs from registered participants. Revenues recovered for ISP projects would then be passed on to TNSPs.

Second, ISP project costs would be allocated across all NEM customers based on consumption ($/MWh). As noted above, the beneficiaries of investment in strategic projects will likely change over time. As such, allocating costs based on modelled beneficiaries may not provide an enduring solution. Allocating costs based on consumption is a pragmatic approach with an in-built mechanism to amend cost allocations over time as the beneficiaries change, assuming that consumption is a reasonable proxy for identifying those that benefit from the investment.

This approach assumes that the AEMC is able to confer this function on AEMO under the NER, and that a legislative change is either forthcoming, or not required, to amend AEMO's statutory functions. AEMO is required to develop, review, consult on and publish its proposed structure for participant fees. The NER require AEMO to have regard to the NEO in determining participant fees. The structure of participant fees must also be consistent with a number of principles, set out in the NER.[36] The principles that AEMO must have regard to are fairly high level and give AEMO a considerable amount of discretion about how costs are recovered and from whom. This contrasts with the approach to transmission pricing, which is considerably more prescriptive in the NER and is subject to oversight by the AER.

As such, the principles to guide the development of participant fee structures would need to be amended to ensure they were fit for purpose for recovering ISP project costs. This includes

[35] PIAC considered an alternative approach whereby AEMO would collect revenue from transmission customers on behalf of the TNSPs according to an approved pricing methodology, similar to its role in Victoria. While there is some merit in this approach, it was dismissed on the basis that it would require jurisdictions to authorise AEMO to exercise it declared network functions under legislation in their own jurisdiction, as well as amendments to the National Electricity Law to limit AEMO's role outside of Victoria to redistributing transmission costs (i.e. so that the contestable arrangements for the shared transmission network would not apply).

[36] NER 2.11.1(b).

specifying the way in which these costs are recovered ($/MWh) and specifying the parties from whom ISP transmission project costs would be recovered. PIAC expects the parties being charged would likely be Market Customers and Integrated Resource Providers (once the Integrating Energy Storage Systems rule is in place from June 2024).[37][38] This differs from solution 1 where costs are passed to transmission customers. Under either approach, it is ultimately end-use customers who would pay.

As above, consideration will need to be given to whether all ISP investments should be subject to this approach, for example where upgrades are made to existing interconnectors, or (extremely rare) instances where projects are deemed to be truly 'local', in the sense that all the benefits of the given project fall within a single region. Similarly, the AEMC may wish to consider whether ISP projects that are not associated with an interconnector should be excluded on the basis that intra-regional investments are likely to reflect jurisdictional policy decisions designed to deliver benefits to customers and communities in the relevant jurisdiction, rather than across the NEM as a whole.

This solution is intended to be a pragmatic approach to recovering ISP project costs. It avoids locking in an assumed benefits ratio that is likely to change over time, and simplifies payment flows by centralising them via AEMO. However, PIAC notes it would be complex to implement. In addition to considering whether the AEMC is able to confer this statutory function on AEMO, there are likely to be a number of other potential barriers. For example, that some large customers and batteries receiving a negotiated transmission service from TNSPs can pay reduced shared network charges compared to the prescribed service. It is unclear how AEMO would take this into account in assigning costs for strategic transmission projects.

The solution shares similarities with the 'NEM-wide cost reflective network pricing' option considered in the AEMC's rule determination on Inter-regional transmission charging 2013.[39] At that time the AEMC noted many favourable aspects of the option, though the rule change implemented an alternative option. Specifically, the AEMC's assessment was positive on pricing efficiency (p. 27), transparency (p. 32), and regulatory stability (p. 33).

6.3 Solution 3 – Amending inter-regional transmission charges

Under this solution, existing mechanisms for calculating inter-regional transmission charges would broadly remain the same. Costs would be recovered for ISP projects under these same mechanisms.

Two key changes would be made.

The first change is to move away from the current 50:50 split of the prescribed TUOS service revenue requirement to allow a greater proportion to be recovered from another region. It would

[37] As noted previously in this rule change request, while PIAC supports a model under which the risks of transmission investment are not fully borne by customers, these models are being considered under a separate process and it is not appropriate for AEMO to have discretion about the parties from whom transmission costs are recovered.

[38] Some large customers and batteries receive a negotiated transmission service from TNSPs and either pay less or receive reduced shared network charges compared to the prescribed service. There is a consultation required on the question of how AEMO would take these arrangements into account when determining the participant fee structures.

[39] AEMC, Rule determination: National Electricity Amendment (Inter-regional transmission charging) Rule 2013. 28 February 2013.

amend the Rules to permit any allocation of prescribed TUOS service ASRR that best reflects a 'beneficiaries pays' approach. Additional principles would likely be required in the NER to provide guidance on how this allocation should occur, and these principles should also be reflected in pricing methodologies. Additional guidance and transparency would be required given the materiality of the decision to TNSPs and transmission customers in other jurisdictions.

The second change is to alter the MLEC calculation to be based on a metric that better reflects the *value* of flows rather than just the quantum of flows at peak times. Basing the MLEC on the value of flows would better reflect the benefits that are transferred across regions. A practical option to achieve this is to weight the volume of flows by wholesale prices. Price, or value, is also a better proxy for reliability benefits than flows. The MLEC could also include metrics such as system security and ancillary services. PIAC considers the exact methodology to apply should be informed by modelling to better understand the likely impacts and which approach would best meet the objectives outlined above.

The MLEC would apply in its revised form to existing intra-regional transmission investments and existing interconnectors.

As occurs now, charges would only be allocated between two interconnected regions.

This solution has the benefit of being simple, low cost to introduce since it relies on existing processes, and market participants already understand how this mechanism works.

It also has the benefit of accommodating shifts in beneficiaries over time. This differs from alternative models that lock in the relative cost share at the time of the investment or require complex modelling or a proxy approach to update the cost shares over time.

7. How the proposed rule will contribute to the NEO

Each of these approaches would expose consumers to prices for transmission services that are more reflective of who the beneficiaries are in providing those services.

Efficient investment will be more likely to proceed where consumers that benefit from that investment face the costs. Importantly, efficient investment is also more likely to proceed where consumers are not facing costs in excess of the benefits they receive from investments. As noted above, there is a risk that some projects that have been identified as being on the optimal transmission path under the ISP and have therefore been deemed efficient investment, such as Marinus Link, would not proceed if a subset of customers is required to pay the majority of the costs while others receive the majority of the benefits. By directing the costs to the identified beneficiaries, more efficient investment in electricity services would occur.

Cost reflective prices also promote allocative efficiency. Consumers are more likely to use electricity efficiently when they face a price that reflects the cost required to supply them.

It is reasonable to expect that efficient investment would, on balance, promote the aim of emissions reductions and the achievement of targets set by participating jurisdictions. The change could enable investment decisions that would not be deemed efficient if the beneficiary pays principle was not implemented, and this would create more capacity for new renewable generation to connect to the NEM.

The alternative case, where an investment is not made that would have been if the proposed change was not made is more ambiguous and depends on the choice of alternative investment made to solve the identified problem. As much as can assumed is that the investments would be more efficient from a consumer perspective, and the decision would also be shaped by the imperative to balance the different elements of the NEO.

Finally, the identified solutions are more consistent with competitive market outcomes where consumers only pay for services where the value outweighs the cost. Where consumers other than the beneficiaries pay for an investment, there is a risk that the benefits to those customers do not outweigh the costs. Again, by requiring the beneficiaries to pay for an investment, regulatory outcomes will be more consistent with competitive market outcomes for customers. As noted previously by the AEMC, this will improve the credibility of, and confidence in, regulatory processes.

Solution 1 will best align beneficiaries with projected flows and so is most likely to achieve efficient investment signals in a manner consistent with the current approach.

8. Expected impacts

In each of the three solutions, customers could be affected by existing cost allocations being distributed in a different way. This could result in higher prices for customers in some jurisdictions that have previously received benefits from transmission investment in other regions which they have not faced the full costs for.

Each solution would require changes to TNSPs' systems and pricing methodologies in order to implement them. However, these changes will have a low impact on costs with minimal impact on existing systems relative to the benefits. While TNSPs would incur some costs implementing the solutions, overall they will still be able to recover the same amount of revenue for their prudent and efficient investments, it will simply be allocated in a different way.

Solutions 1 and 2 would also require amendments to AEMO's systems to allow AEMO to take on the role of coordinating inter-regional transmission cost recovery. For solution 1, given that AEMO already has a role as the coordinating NSP in Victoria, this would simply be an extension of one aspect of that role. Similarly, AEMO already has to conduct modelling of the distributional impacts of ISP projects. As such, these changes are also unlikely to be costly. For solution 2, AEMO's new role would expand the range of costs that AEMO would need to recover as part of its existing budgeting processes and mechanisms for recovering participant fees.

The AER would incur some costs in amending its Transmission Pricing Methodology Guideline under each solution. Solution 1 would have the added requirement of changes to the RIT-T guidelines.

Retailers would be impacted under Solution 2 if AEMO increased its prudential requirements to ensure it is kept whole in facilitating the redistribution of transmission costs via participant fees.

This could have repercussions for retailers, particularly small retailers, and transmission-connected customers. Additional rule changes may be required to ensure this option was available to AEMO. Additional consideration would also be required in respect of the retailer of last resort framework to ensure this remained fit for purpose.

Generators would not be affected by the proposed changes.

8.1 Revenue and Pricing principles

PIAC notes that the AEMC is required to consider the revenue and pricing principles in the National Electricity Law in assessing a Rule change proposal. In our view, the following revenue and pricing principle is most relevant to this Rule change:

> Regard should be had to the economic costs and risks of the potential for under and over utilisation of a distribution system or transmission system with which a regulated network service provider provides direct control network services.[40]

PIAC considers that the proposed solutions presented in this Rule change request promotes this principle by improving the cost reflectivity of the prices charged by TNSPs and thereby encouraging more efficient use of the transmission network. As already noted, however, the primary rationale for the proposed solutions is that they promote the NEO.

The three solutions proposed pose different propositions with respect to promoting simplicity and transparency. We have noted above that the third solution has the benefits of being simple and having low introduction costs. The increased complexity of the other two solutions is offset by the benefits respectively of increased accuracy in the cost allocation and dynamism over time.

[40] Section 7A(6), National Electricity Law, Schedule 1, National Electricity (South Australia) Act 1996 (SA).

Appendix A

	Cost Allocation/Pricing Principles	Payment Flow
Existing MLEC	Calculations are made by the Co-ordinating Network Service Provider for a region, using the MLEC CRNP methodology. Allocation is based on volume of flows.	Collection and distribution of payment flows is coordinated by Co-ordinating Network Service Providers
Solution 1	• AEMO calculates market benefits accruing to each region at the time of project approval. • The forecast distribution of market benefits by NEM region is used to allocate the costs of the project to jurisdictions. • The initial allocation may be revisited over time.	• Revenue could be recovered under the existing structures. • Alternatively, responsibilities for collection and distribution of payment flows could be moved from the Co-ordinating Network Service Providers to AEMO.
Rules amendments likely to be required to give effect to the proposed change	Amendment of Rule 6A.19 Cost Allocation; Rule 6A.23 Pricing Principles; and Rule 6A.29A.1 Modified Load Export Charges. Addition of new rules/clauses will be needed to detail how AEMO will determine the benefit to each region and the amount of the costs to be allocated to each region for ISP projects.	Amendment of Rule 6A.29A.1 Modified Load Export Charges. Possible addition of a new rule/clause detailing how AEMO will administer payment flows for ISP projects.
Solution 2	• ISP project costs are allocated across all NEM customers based on consumption ($/MWh) • AEMO is responsible for the calculation.	• AEMO receives revenues for ISP projects via participant fees, which are charged to registered participants. • These are passed on to TNSPs
Rules amendments likely to be required to give	Amendment of Rule 6A.19 Cost Allocation; Rule 6A.23 Pricing Principles; and Rule 6A.29A.1 Modified Load Export Charges.	Amendment of Chapter 2, Registered Participants and Registration – Rule 2.11 Participant Fees, and Rule 6A.29A.1 Modified Load Export Charges.

effect to the proposed change	Addition of new rules/clauses will be needed to detail how AEMO will determine the benefit to each region and the amount of the costs to be allocated to each region for ISP projects.	Addition of a new rule/clause detailing how AEMO will administer payment flows for ISP projects.
Option 3	• The MLEC is calculated on a basis of value of flows. For example, this could be calculated using volumes weighted by wholesale prices.	• No change to the existing payment framework
Rules amendments likely to be required to give effect to the proposed change	Amendment of Rule 6A.29A.1 Modified Load Export Charges	Minor amendments to Rule 6A.29A.1 Modified Load Export Charges if required.