TasNetworks

Discussion Paper:

"Beneficiaries pay" pricing arrangements for new interconnectors

Contents

Executive Summary

Australia's energy sector is undergoing unprecedented change. To ensure Australia's energy supply is affordable, reliable, secure and cleaner into the future, the National Electricity Market (**NEM**) will need diverse generation sources, energy storage and dispatchable on-demand energy.

In its role as the national transmission planner, AEMO has identified the need for greater interconnection between the NEM regions. Greater interconnection provides each region with increased capacity to trade with one another, allowing each region to benefit from the natural diversity in renewable generation. The overarching planning objective is to make timely and efficient transmission investments to help minimise the costs of satisfying industrial, commercial and residential demand for electricity.

In this context, the COAG Energy Council's recent communique[1] highlighted the importance of AEMO's Integrated System Plan (**ISP**) and noted that key transmission projects are being progressed, including KerangLink, HumeLink, Marinus Link and Energy Connect. The COAG Energy Council has also asked the Energy Security Board (**ESB**) to consider the charging arrangements for interconnector projects, commenting[2]:

> "Recognising that interconnectors should only proceed based on a positive cost/benefit assessment, the Council has asked the ESB to prepare advice on a fair cost allocation methodology (both in theory and practice) as part of its work to action the ISP."

TasNetworks welcomes the ESB's engagement on the important issue of interconnector pricing. In the Initial Feasibility Study for Marinus Link, we committed to work with policy makers, regulators and market bodies to seek appropriate customer pricing outcomes. In light of this commitment, the purpose of this Discussion Paper is to start the conversation amongst stakeholders by setting out our understanding of the current Rules and why we consider it timely to introduce targeted, proportionate reform.

Our starting point is to note that the Regulatory Investment Test for Transmission (**RIT-T**) imposes a commercial discipline on TNSPs in relation to their investment decisions, by considering alternative options, including non-network options, across a range of different scenarios. In addition, revenue regulation under Chapter 6A provides TNSPs with incentives to minimise the costs of providing transmission services without compromising performance.

1 COAG Energy Council, Meeting Communique, 22 November 2019.

2 Ibid, page 2.

The RIT-T and the revenue setting arrangements have been refined over many years to drive the kind of behaviours and outcomes that would be expected in a competitive market. However, the same cannot be said of the transmission pricing arrangements. Our analysis shows that these arrangements are not consistent with the 'beneficiaries pay' principle, which means that new interconnector projects in Australia may lead to inequitable outcomes for customers in particular NEM regions.

The evidence from our stakeholder engagement process for Marinus Link is that customers will not support projects unless they have a clear understanding of the benefits they will receive. As a consequence, the National Electricity Objective is being undermined by the current pricing Rules because efficient projects will not be supported unless the resulting charges to customers can be justified; at present, they cannot.

The experience of transmission pricing reform in Australia is that opportunities to deliver better outcomes are sometimes thwarted by an unrealistic ambition to implement 'perfect' solutions. The evidence from the United States, which implemented the beneficiaries pay principle in 2011, shows that it is not necessary or appropriate to estimate beneficiaries with a high degree of precision.

This Discussion Paper examines a number of questions that need to be addressed in developing a better pricing methodology for interconnectors. Of course, we recognise that stakeholders will have a range of different views on how these questions should be addressed. As an opening contribution to the discussion, however, we present our response to each of these questions, having regard to the evidence from other jurisdictions and the particular features of the regulatory framework in the National Electricity Rules.

To further assist stakeholders and the ESB, we also provide a potential way forward that would give effect to our suggested approach. Proportionate, incremental changes to the existing Rules could significantly improve the pricing arrangements for new interconnector projects, including required supporting AC shared network investments, and thereby promote the achievement of the National Electricity Objective.

1 Introduction

1.1 Objective and structure

Our objective in preparing this Discussion Paper is to assist stakeholders in understanding:

- the deficiencies with the current Rules insofar as they relate to interconnector cost recovery;
- the principles that should govern the pricing arrangements for interconnectors, having regard to AEMC's 2013 determination on inter-regional transmission pricing;
- the experience in other countries, which have successfully implemented the beneficiaries pay principle to promote efficient transmission investment; and
- a potential way forward to provide a better outcome for customers.

With these objectives in mind, this Discussion Paper is structured as follows:

- Chapter 2 describes the issues to be addressed, starting with a description of the current pricing arrangements for regulated interconnector assets.
- Chapter 3 discusses the principles that should apply to transmission pricing, having regard to the AEMC's 2013 determination on inter-regional transmission pricing. It also discusses the approach to implementing the beneficiaries pay principle in New Zealand and the United States.
- Chapter 4 discusses the key design questions that must be addressed in determining the future interconnector pricing arrangements for the NEM; and
- Chapter 5 outlines a possible way forward, for consideration.

1.2 Feedback

Stakeholders and customers are invited to contact us to request a briefing or provide feedback on this Discussion Paper by 2 March 2020.

Stephen Clark

Technical and Economic Leader, Project Marinus

PO Box 606, Moonah TAS 7009

Email: team@marinuslink.com.au

2 Issue to be addressed

This Chapter describes the issues that arise from the current Rules. It is structured as follows:

- Section 2.1 provides an overview of the current arrangements that apply to inter-regional transmission pricing.
- Section 2.2 explains why the current pricing arrangements fail to promote efficient investment in new interconnector projects, contrary to the National Electricity Objective.
- Section 2.3 discusses whether broader reform to transmission pricing is warranted.

Key messages

- Historically, the allocation of an interconnector's costs between NEM regions has followed a two-step approach:
  - An initial allocation based on the geographical location of the assets; and
  - A recharging mechanism between adjacent regions for the use of one another's assets, known as the Modified Load Export Charge (**MLEC**).
- The current Rules are unlikely to allocate the costs of new interconnectors to each NEM region according to the benefits each region receives. This mismatch arises primarily because the current approach to allocation - on the basis of geographic location of the assets - is not necessarily reflective of attributable benefits, and the MLEC allocates the costs according to each region's use of the interconnector, rather the value they obtain from it.
- Marinus Link provides a useful case study to illustrate the materiality of the mismatch between the likely allocation of the project costs and the beneficiaries. It also highlights the concerns expressed by our customers.
- It appears that the current transmission pricing arrangements for interconnectors may lead to much needed projects not proceeding, despite satisfying the RIT-T. The current pricing arrangements therefore risk undermining the National Electricity Objective, which is concerned with promoting efficient investment.

2.1 Overview of current arrangements

The AER is responsible for setting the maximum allowed revenue for regulated transmission assets through periodic revenue determinations. As an interconnector provides transmission services between two connected regions, a key question is how the regulated revenue allowance (termed the Aggregate Annual Revenue Requirement or **AARR**) should be recovered across the NEM regions, and then across customers in each region.

Historically, the jurisdictions/TNSPs in each of the connected regions have agreed that the revenue to be recovered in each region should reflect the physical location of the assets[3]. So, for example, if the interconnector project's assets are located 45/55 between regions A and B, region A's TNSP would recover 45% of the interconnector's AARR from its customers, while region B's TNSP would recover 55% of the AARR.

Following the agreed allocation of the AARR between regions[4], the recovery of the respective revenue from each region is undertaken in accordance with each TNSP's pricing methodology, which is subject to AER approval at the time of its revenue determination. These pricing methodologies must be consistent with the Rules requirements relating to transmission pricing, which are set out in Part J of Chapter 6A, and the AER's current Transmission Pricing Methodology Guidelines[5]. It is worth recalling that the current arrangements recover the costs of the 'shared network' only from load customers[6]. We will return to this issue later in this submission.

For the purpose of this Discussion Paper, it is not necessary to explain the pricing methodology in detail. Instead, Figure 1 below provides a summary of how the AARR is allocated to different services and how 'shared network' services are then allocated 50/50 between locational and non-locational charges, before being converted to prices. The orange boxes show various adjustments that are made to the AARR for each TNSP to determine the final amount that will be recovered from load customers.

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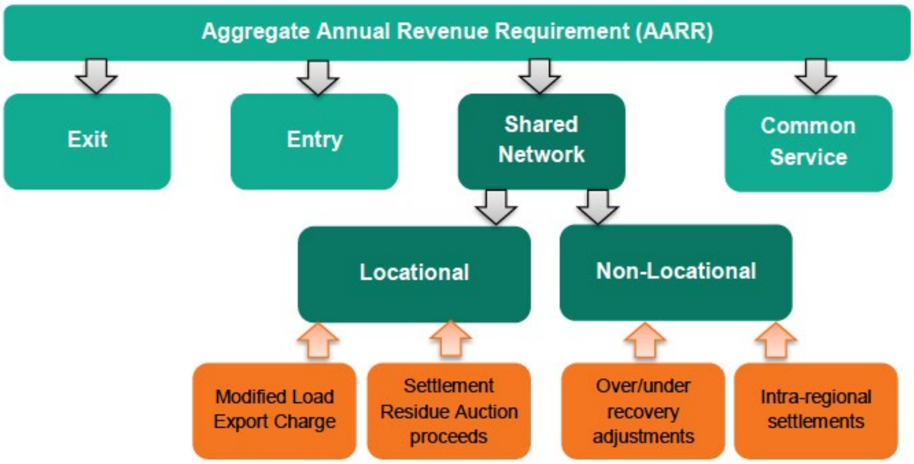
3 The historical examples include Murraylink and Directlink, which predate the existing Rules. A geographic allocation of costs for the Heywood interconnector upgrade was also adopted in 2013. TNSPs may agree to share the costs of the investment, which is another method for allocating the costs between the two regions.

4 We note that the Rules do not contemplate such an agreement between the regions, but the description here is consistent with historical practice. An alternative view is that the costs of the interconnector would depend on the regional boundary, which could result in the costs of the interconnector falling entirely in one region or the other.

5 AER, Transmission Network Service Providers, Pricing Methodology Guidelines, July 2014.

6 The AEMC's Final Report on its Coordination of Generation and Transmission Investment concluded that these arrangements should be reviewed. We will return to this issue in the next chapter of this Discussion Paper.

Figure 1: An overview of the pricing Rules in Part J of Chapter 6A



One of the adjustments shown in orange is the Modified Load Export Charge (**MLEC**)[7], which is highly relevant to the question of 'who pays' for regulated interconnectors.

The MLEC is the mechanism by which each region levies transmission charges on its neighbouring regions, based on inter-regional energy flows. It should be noted that the MLEC applies to all regulated transmission network assets, including regulated interconnectors.

The concept behind the MLEC is that connected regions make use of one another's networks and, therefore, should make a contribution to the costs of those networks. As both neighbours apply MLEC charges on one another, each makes a net MLEC adjustment[8] to the revenue that it recovers from its customers[9]. This concept is illustrated in the following hypothetical example:

- Region A levies an MLEC of $3 million on Region B (for the use that Region B makes of Region A's network); and
- Region B levies an MLEC of $2 million on Region A (for the use that Region A makes of Region B's network); then
- Region B includes an additional net MLEC of $1 million in its AARR, which is recovered from its customers; and
- Region A recovers its AARR less $1 million, as it receives this revenue from Region B.

It is evident from the above discussion that the MLEC has important implications for 'who pays' for a regulated interconnector. In fact, the AEMC's intention in designing the MLEC is that it

7 Each TNSP is required to apply the MLEC CRNP methodology which is specified clause S6A.3.3 of the Rules to ensure that a consistent approach is adopted across the NEM.

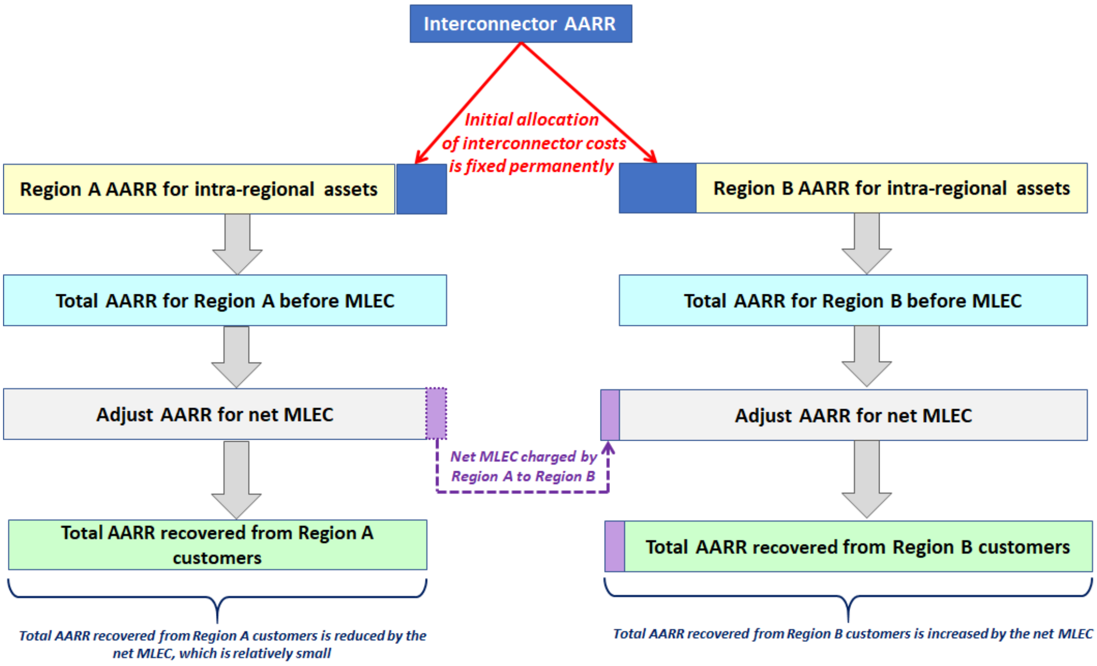
8 It is a net MLEC adjustment because each region both levies and receives MLEC.

9 If there are multiple TNSPs in a region, the Co-ordinating TNSP is required by clause 6A.29A.5 of the Rules to determine how the MLEC amount receivable from or payable to other regions is allocated across the TNSPs in its region.

should allocate costs between regions according to the beneficiaries. As explained in this Discussion Paper, however, the MLEC fails to achieve this objective. We will return to this issue in Chapter 3.

The figure below shows how the MLEC operates, noting the inclusion of the AARR for an interconnector based on an agreed allocation between the jurisdictions.

Figure 2: Allocation of interconnector costs between regions[10]



Whilst the MLEC effectively revisits the initial allocation of the AARR for the interconnector across the two regions (alongside other shared network costs), its overall effect tends to be relatively modest because:

- Only 50% of each region's shared network costs are subject to the MLEC[11]; and
- The MLEC reflects the proportionate use of the transmission system assets at times of greatest utilisation[12], which will lead to relatively modest net charges for interconnector assets if both regions have similar peak import volumes at different times.

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10 As already noted above, this figure reflects the historical practice of allocating the interconnector's AARR between the two connecting regions. Alternatively, it is feasible under the current Rules that an interconnector's AARR is allocated entirely to one region. In this case, the MLEC would work to reallocate a portion of these costs to the other region.

11 See Clause 6A.29.2A.(a)(1) of the Rules. We will return to this issue later in this Rule change proposal.

12 Clause 6A.29.2A.(a)(3) of the Rules.

Consequently, the question of 'who pays' for an interconnector may typically be driven by the initial allocation of the interconnector's AARR between the regions. As already noted, historically for some interconnectors this allocation has reflected the geographical location of the asset. Whilst this allocation method is pragmatic, it is unlikely to reflect the benefits that each region obtains from the interconnector and, therefore, the amount that each region should pay towards it. If the regional benefits are spread more widely than the directly connected regions, the initial allocation between the connected regions cannot reflect the beneficiaries.

Furthermore, if the initial allocation of the AARR does not reflect the beneficiaries, it is unlikely that it will be corrected by the application of the MLEC. This is because the MLEC allocates costs according to the flows across the interconnector, without any regard to the value of those flows to each region.

For example, if electricity imported to Tasmania at times of low prices is stored and later exported to the mainland at times of high prices, the net flows will be zero. However, the net value of those flows, which takes account of the wholesale generation prices and volumes, will show that the mainland end use customers benefit substantially from the interconnector. This example supports Professor William Hogan's observation that models based on network usage may fail to identify the beneficiaries[13]:

> "..despite the common claim otherwise, the power flow model does not provide a good theoretical foundation for estimating benefits."

A further problem with the MLEC is that the AARR for an interconnector can only be re-allocated between the two connected regions. The MLEC does not consider whether costs allocated to Victoria from Tasmania, for example, should be further allocated to New South Wales or South Australia. This is a further source of mismatch between the regions that may be required to pay an interconnector and the regions that benefit from it.

In the next section, we explore whether the failure of the current Rules to allocate the costs of interconnectors according to the beneficiaries has any adverse consequences beyond the issue of fairness. In particular, the key issue in contemplating changes to the current Rules is whether change would promote more efficient outcomes for customers, in accordance with the National Electricity Objective.

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[13] William W. Hogan, Transmission Benefits and Cost Allocation, 31 May 2011, page 2.

2.2 Failure to promote efficient investment

As explained in the previous section, the current Rules create a mismatch between those customers that pay for an interconnector (through annual transmission prices) and those customers that benefit from it. This issue was raised by several stakeholders in their submissions to our Project Specification Consultation Report and our Initial Feasibility Report in relation to Marinus Link:

> "…COTA believes that the addition of another interconnector will benefit the NEM and mainland consumers much more than it would benefit Tasmanian consumers. […] Therefore, COTA would only support Project Marinus if the majority of its cost was borne by mainland NEM regions."[14]

In response to these concerns, 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. This situation has important consequences in relation to the achievement of the National Electricity Objective, which is set out in the National Electricity Law 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."

In recent years, network companies have improved their customer engagement processes to better understand their customers' concerns and preferences. Affordability has been raised consistently as a key issue. Against this backdrop, customer support for demonstrably prudent and efficient network investments is conditional on understanding how customers will benefit from the proposed expenditure.

For a new interconnector transmission project, customer support is also conditional on understanding the pricing outcomes – so that customers in each region are able to understand the benefits they will receive and the increased network charges they will pay. For these projects, therefore, inefficient pricing arrangements have the potential to undermine the case for a project, even if it satisfies the RIT-T. Such an outcome is contrary to the National Electricity

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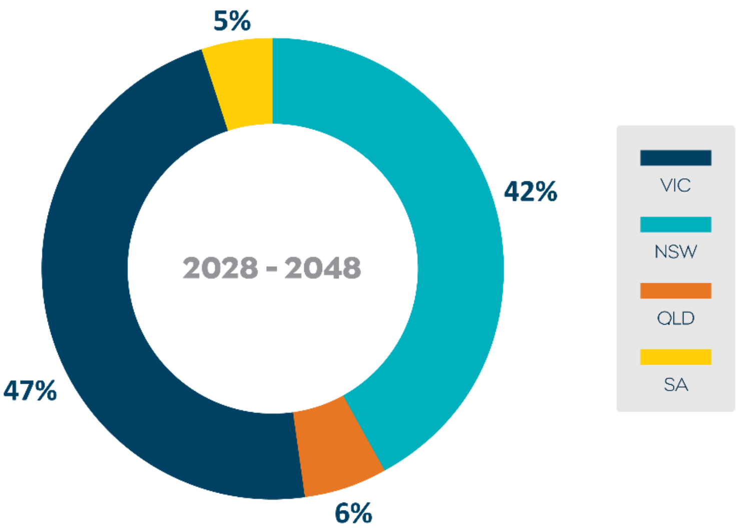
14 COTA, submission in response to Project Marinus Consultation Report, 18 October 2018, pages 3 and 4.

Objective, which is seeking to promote efficient investment for the long term benefit of customers.

As explained below, Marinus Link provides a case study which illustrates this point. We also comment briefly on KerangLink, where similar concerns arise.

On the assumption that Marinus Link proceeds in 2028, the figure below shows the share of total 'customer benefits'[15] that each NEM region will obtain from the project over the 20-year period from 2028 to 2048. It shows that New South Wales and Victoria obtain the majority of the benefits, being 42 percent and 47 percent respectively. Tasmanian electricity customers are no better off with Marinus Link in service[16].

Figure 3: Regional distribution of benefits from Marinus Link 2028-2048



Although Tasmanian electricity customers would be no better off with Marinus Link in service, they would pay a significant share of the project costs under the current transmission pricing Rules[17]. Furthermore, there is a significant mismatch between the distribution of customer benefits across the NEM and 'who pays' under the current transmission pricing Rules. For example, under the current MLEC provisions customers in NSW would make no contribution to the costs of Marinus Link, despite obtaining more than 40% of the customer benefits.

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15 We discuss what we mean by 'customer benefits' later in this paper, which have been derived from our market modelling. At this stage, however, it should be noted that 'customer benefits' differ from the net market benefits that are defined by the RIT-T.

16 The reasons for this outcome are explained in the Project Draft Assessment Report, which has been published at the same time as this Discussion Paper.

17 There is some doubt regarding how the current Rules would allocate Marinus Link's AARR between Victoria and Tasmania, as the physical location of the undersea cables would not be located in either the Victorian or Tasmanian regions as currently defined by the NEM.

We have undertaken a similar analysis for KerangLink, while not so clear cut, shows that NSW would enjoy a greater share of the benefits than Victoria. In that instance, the traditional cost contribution from each region may be about 50/50 – again creating a mismatch between those who pay for the investment and those who benefit from it.

In a competitive market, a customer would not agree to pay for an asset unless they received a benefit from it. The feedback we have received indicates that customers, quite rightly, expect the same principle to apply to proposed transmission interconnector projects.

As explained in the previous section, the current transmission pricing arrangements insofar as they relate to new interconnector projects do not give effect to the beneficiaries pay principle. As a consequence, even if customers recognised that an interconnector project would deliver a net benefit in aggregate terms, the investment is unlikely to proceed if the costs allocated to customers in a region outweigh the benefits those customers receive.

TasNetworks agrees with the concerns expressed by customers in relation to the ‘who pays’ question. In our view, it is incumbent on the project proponent to demonstrate that customers who will be allocated the costs of a proposed interconnector project would be better off if the project proceeds. If the pricing arrangements deliver outcomes that are not in customers’ interests, then the project should not proceed as a regulated transmission investment. For projects that satisfy the RIT-T, such an outcome would be contrary to the interests of NEM customers as a whole.

2.3 Are these issues confined to new interconnector projects?

The discussion in the previous section described the negative customer impact of the current transmission pricing arrangements insofar as they relate to new interconnector projects. However, the transmission pricing arrangements do not contain specific provisions relating to new interconnector projects, as distinct from intra-regional investments or historical investments (i.e. existing assets). A question arises, therefore, whether the issues raised in section 2.2 have wider implications that should also be addressed.

In general, if the transmission pricing arrangements fail to allocate costs on a ‘beneficiaries pay’ basis, it may lead to sub-optimal locational decisions; inefficient use of transmission assets; and inefficient transmission investment decisions. Potentially, these adverse outcomes could arise in relation to pricing for transmission services generally, not just for new interconnector projects.

We also note that a common pricing method currently applies across all transmission assets, without any specific provisions relating to new interconnector projects. A common pricing method avoids artificial distinctions between intra- and inter-regional transmission investments, particularly as intra-regional augmentations may have the effect of increasing interconnector capacity.

These observations could lead to the following conclusions:

- Any reform to the transmission pricing arrangements should not be confined to new transmission interconnector projects; and
- It is not appropriate to treat interconnector projects on a different basis to intra-regional projects.

Whilst we accept that in some respects new interconnector projects should not be treated as a special case, we think there are distinct advantages in developing specific pricing provisions for these projects. In particular, we note that:

- There is very significant investment planned in new interconnector projects as the NEM transitions to a lower carbon future. Given the potential value of this investment, it is essential to establish pricing arrangements that promote efficient investment.
- The regional allocation of major new interconnector projects, such as Marinus Link and supporting transmission, raise customer concerns that are unlikely to apply to intra-regional investments, which typically have a more modest impact on transmission charges.
- The specific concerns in relation to promoting efficient investment do not apply to existing transmission assets (as the investment decisions have already been made).
- The history of transmission pricing reform in Australia is that reform is often protracted. There is an urgent need to bring about meaningful reform in relation to new interconnector projects to address the issues raised, without undue delay.

For the above reasons, we consider it appropriate to address the specific issues arising in relation to new interconnector projects, rather than broadening out the transmission pricing reform. We note that the COAG Energy Council is also focusing on the pricing arrangements for interconnectors in making its request that the ESB should advise on this specific issue.

In Chapter 4, we discuss the key questions that must be addressed in designing new pricing arrangements. Before turning to these questions, however, we discuss the economic principles that should help address the question of ‘who pays’ for new interconnector projects.

3 Economic principles to determine the 'who pays' question?

The previous chapter explained that the current pricing arrangements may undermine efficient interconnector transmission projects because they do not satisfy the 'beneficiaries pay' principle. Whilst the 'beneficiaries pay' principle may have intuitive appeal, it is important to consider whether it can be supported with reference to efficient pricing principles and regulatory practice. Furthermore, in developing alternative pricing arrangements, it is important to consider what other principles ought to guide the approach to transmission interconnector pricing.

To address these issues, this chapter is structured as follows:

- Section 3.1 discusses the AEMC's pricing principles in developing the current Rules for inter-regional charging in 2013; and
- Sections 3.2 and 3.3 discuss the application of the beneficiaries pay approach in New Zealand and the United States, respectively.

Key messages

- The AEMC applied 6 pricing principles in developing the current transmission pricing Rules in 2013. These principles, which include 'beneficiaries pay', remain relevant and should be retained.
- The AEMC's 2013 determination explained that it supported the beneficiaries pay principle, but considered that this was best achieved through the application of the MLEC. In the AEMC's view, the MLEC was considered better able to match the allocation of costs with the beneficiaries, which were likely to change significantly over time.
- In practice, as shown in the previous chapter, the current pricing arrangements do not allocate the costs of new interconnector projects to the beneficiaries.
- The evidence from New Zealand and the United States supports the adoption of a beneficiaries pay approach. New Zealand has embarked on reform, whilst the United States successfully implemented this principle since its introduction in 2011.
- The evidence from the United States is that market participants accept the beneficiaries pay principle, which has been applied without significant disputes. The calculation of the beneficiaries is not revisited periodically – a position that is strongly supported by Professor William Hogan.

3.1 Review of the AEMC's principles

In developing the current inter-regional transmission pricing arrangements in 2013[18], the AEMC applied 6 pricing principles, which it considered would promote the National Electricity Objective. In the table below we provide a short description of each of the AEMC's principles.

Table 1: AEMC's 2013 Inter-regional TUOS Principles

Principle	What does it mean?
Efficient transmission pricing	Prices should reflect marginal cost
Regional beneficiaries pay	Each region should pay according to the benefits it receives
Regulatory stability	Changes should be manageable, understandable and proportionate
Administrative efficiency	Costs of implementation should be considered
Transparency	The way charges are derived and applied should be transparent
Customer impacts	Prices should not be overly onerous or volatile

In our view, the AEMC's 2013 principles have considerable merit. Furthermore, it seems appropriate that any proposed change to the current Rules could be tested against the above principles.

It is noteworthy that 'beneficiaries pay' is one of the principles adopted by the AEMC. In its COGATI report in December 2018, the AEMC recapped on its application of these principles in adopting the current inter-regional transmission pricing methodology[19]:

> *"A beneficiary pays approach is based on the idea that the most efficient allocation of resources occurs when consumers pay the full cost of the goods that they consume.*
>
> *An alternative approach would be to use long-run marginal cost pricing.*
>
> *[…]*
>
> *There are similarities in price outcomes between the two approaches, but also some important differences:*

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18 AEMC, Rule Determination, National Electricity Amendment (Inter-regional transmission charging) Rule 2013, 28 February 2013, pages 18-20.

19 AEMC, Final Report, Final Report on the Coordination of Generation and Transmission Investment, pages 101, 102 and 103.

- *Similarities – […] Both philosophies use flow-based analysis to allocate the historical or future costs of a transmission asset to downstream consumers.*

- *Differences - The beneficiary pays model does not reflect spare capacity, whereas in a long run marginal cost model if capacity is tight, increased consumption is more likely to prompt new investment, implying a higher long run marginal cost (and vice versa).*

> *[…]*
>
> "*Broadly, the existing [MLEC] arrangements should, over time, adequately ensure that those who benefit from the interconnector pay for the interconnector.*"

The AEMC favoured LRMC pricing as a means of achieving the beneficiaries pay principle for the following reasons[20]:

> *"The Commission's key concern with the particular beneficiary pays option that it considered in 2013 was that it locked in for perpetuity an initial estimate of benefit allocations. These predictions might well turn out to be wrong - and even perverse - from the viewpoint of future customers (given that transmission assets are paid off over 30 or 40 years).*
>
> *[…]*
>
> *In order to avoid these inefficiencies, the Commission considered instead that inter-regional charges should be updated regularly to reflect the current use of the interconnector assets. While this could potentially be done by periodically revisiting the benefit predictions, it is likely that this would be problematic and contentious - driven by the winners or losers at that particular point in time. So, the AEMC decided that adapting IR-TUOS charges [MLEC] to new and varying circumstances was best done annually, using the locational method for intra-regional charging. In effect, this adopted a beneficiary type approach."*

It is evident from the above discussion that the AEMC supports the beneficiaries pay principle, but concluded that this principle would be best achieved through long run marginal cost pricing, hence its preference for MLEC.

Unfortunately, however, our analysis illustrates that these arrangements applied to projects such as Marinus Link and to a lesser extent KerangLink do not provide an outcome consistent with the beneficiaries pay principle. As explained in the previous chapter, the MLEC approach will not achieve an outcome consistent with the beneficiaries pay principle for the following reasons:

- The initial allocation of an interconnector's AARR between regions dominates the MLEC in determining 'who pays'[21].

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20 Ibid, page 102.

21 As explained in Chapter 2, the historical allocation approach adopts an allocation based on the geographical location of the assets, which does not reflect the regional benefits.

- The MLEC allocates costs between regions on the basis of flows across the interconnector, which may not reflect the benefits enjoyed by each region.

In our view, there is strong evidence to suggest that the operation of the current Rules in respect of new interconnector projects does not satisfy the beneficiaries pay principle. As such, it is reasonable to conclude that changes could be made to the current Rules to deliver an overall improvement for customers.

Before considering alternative options, it is instructive to examine how other jurisdictions have applied the beneficiaries pay principle. In the following sections, we discuss the application of this principle in New Zealand and the United States.

3.2 Evidence from New Zealand

In preparing this Discussion Paper, TasNetworks discussed the recent experience of transmission pricing reform with New Zealand's Electricity Authority. The key points arising from this discussion are summarised here.

The Electricity Authority was established in November 2010 following a Ministerial Inquiry which abolished the predecessor Electricity Commission and replaced it with a slimmed-down Electricity Authority, with far fewer objectives and functions than the Commission. Section 15 of the Electricity Industry Act 2010 provides the Electricity Authority with a single statutory objective:

> "To promote competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers."

The Electricity Authority's position is that the current transmission pricing methodology is not cost reflective and so distorts investment incentives for generation and demand response. As a result, the Electricity Authority argues, this reduces "competition" between transmission options and non-network alternatives in the Commerce Commission's Grid Investment Test[22]. This has justified the continuation of a review of transmission pricing arrangements, which was initiated by the Electricity Commission in 2007.

The Electricity Authority has produced numerous transmission pricing proposals since 2010. In July 2019, it published a substantially revised Issues Paper explaining that[23]:

> "The Authority believes the current TPM [Transmission Pricing Methodology] encourages inefficient use of and investment in the transmission grid.
>
> Consumers should pay for the transmission assets they benefit from, and not pay for

22 The Grid Investment Test is analogous to the RIT-T in Australia.

23 Electricity Authority, Summary document: Transmission pricing for the future, 23 July 2019, page 1.

those they do not. That's not how the current charges work. Under the current TPM, the costs of regional transmission investments are spread across all consumers, regardless of where they live or the benefits they get.

> **A benefit-based approach to transmission charges**
>
> The Authority proposes a benefit-based approach to allocating transmission costs. This means transmission customers who benefit from specific grid investments would pay for them.
>
> We propose two new charges to replace the current regional coincident peak demand (RCPD) charge and the high voltage direct current (HVDC) charge:
>
> - A benefit-based charge to recover the costs of new grid investments and the depreciated costs of seven major existing investments based on their benefits to transmission customers
> - A residual charge to recover any remaining transmission costs in a way which does not distort incentives to invest [in] or use the grid."

The proposed approach applies to all new investment in transmission and seven historic investments, including the upgrades to both pole 2 and pole 3 of the HVDC interconnector because[24]:

> "South Island generators pay for all of the costs of the high voltage HVDC line that transports electricity between the South and North Islands. The HVDC charge has been about 10 percent of the wholesale price of electricity. The charge is like a tax on South Island generation and encourages investment in otherwise more expensive North Island generation."

Reallocating certain historic asset costs under a beneficiaries pay method has proved to be the most controversial feature of the Authority's proposal. Despite strong advocacy against re-determining beneficiaries of sunk assets in previous consultations, the Electricity Authority commented that[25]:

> "…[sustainability] would be undermined if consumers in some regions would have to pay both for new investments made for their benefit and continue to pay for major investments they didn't benefit from."

The beneficiaries pay approach in relation to the HVDC line is calculated by running the dispatch results of 4 years of historic offer data with and without the transmission investment through the Electricity Authority's Scheduling, Pricing and Dispatch model, which is a precise

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24 Ibid.

25 Electricity Authority, 2019 Issues Paper, Transmission pricing review Consultation paper, 23 July 2019, page iv.

replica of the dispatch engine used by the System Operator. The Electricity Authority's issues paper explains that 77% of the benefits that the seven major investments generate accrue to upper North Island customers, but those customers currently pay only 35% of the costs of those investments.

New Zealand's approach to applying the beneficiaries pay principle includes some reopeners that would apply in specific circumstances. However, the intention is not to revisit the assessment of beneficiaries and the resulting cost allocations. In adopting this approach, the Electricity Authority recognised that a periodic reassessment of the beneficiaries may distort incentives for investment in DER (e.g. batteries) for the main purpose of avoiding transmission charges. In reaching this view, the Electricity Authority considered the evidence from the United States, which we discuss next.

3.3 Evidence from the United States

In the United States, FERC's Order 1000 in 2011 implemented reforms to ensure that the costs of transmission solutions chosen to meet regional transmission needs are allocated fairly to those who benefit from them[26]. In supporting the application of a beneficiaries pay approach, FERC commented that[27]:

> "…if costs would be allocated to entities that will receive no benefit from a transmission facility, then those entities are more likely to oppose selection of the facility in a regional transmission plan for purposes of cost allocation or to otherwise impose obstacles that delay or prevent the facility's construction."

FERC referred to its earlier Order No.890, which recognised the importance of linking transmission planning with the cost allocation outcomes[28]:

> "The Commission explained that knowing how the costs of transmission facilities would be allocated is critical to the development of new infrastructure because transmission providers and customers cannot be expected to support the construction of new transmission unless they understand who will pay the associated costs."

FERC's decision to reform the cost allocation arrangements reflected a concern that had been widely expressed by stakeholders that the previous arrangements were undermining efficient investment[29]:

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[26] Federal Energy Regulatory Commission, Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, 21 July 2011, page 10.

[27] Ibid, paragraph 486.

[28] Ibid, paragraph 495.

[29] Ibid, paragraph 496.

> "We agree with many commenters that the lack of clear ex ante cost allocation methods that identify beneficiaries of proposed regional and interregional transmission facilities may be impairing the ability of public utility transmission providers to implement more efficient or cost-effective transmission solutions identified during the transmission planning process.
>
> […]
>
> Failing to address the allocation of costs for these transmission facilities in a way that aligns with the evaluation of benefits through the transmission planning process could lead to needed transmission facilities not being built, adversely impacting ratepayers."

The cost allocation principles adopted by FERC include the following requirements[30]:

1. The costs of transmission facilities must be allocated to those that benefit in a manner at least roughly commensurate with the estimated benefits received.
2. Those that receive no benefit from transmission facilities, either at present or in a likely future scenario, must not be involuntarily allocated the costs of those facilities.
3. The cost allocation method and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent with adequate documentation to allow a stakeholder to determine how they were applied to a proposed transmission facility.

The concept of 'roughly commensurate' reflects decisions by the US courts that there is no requirement on FERC to allocate costs with exacting precision. It should also be noted that the beneficiaries pay principle applies to new investments – it does not apply to existing assets.

To understand how these arrangements have worked in practice, New Zealand's Electricity Authority, the Commerce Commission and Transpower visited a number of Independent System Operators (ISOs) and Regional Transmission Operators (RTOs), including New York ISO (NYISO); the New York Department of Public Service (DPS); the Midcontinent ISO (MISO); and PJM Interconnection (PJM). A joint report was published setting out their findings[31], which included the following observations[32]:

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30 Ibid, paragraph 486. It should be noted that FERC has adopted 6 pricing principles. For the sake of brevity, the discussion here focuses on those principles that are most relevant.

31 Beneficiaries-pay in USA, Discussions on implementation of beneficiaries-pay cost allocation for transmission investment Joint report: Electricity Authority, Commerce Commission and Transpower, 20 June 2018.

32 Ibid, page iii.

- Each of the three ISOs / RTOs we met operates a beneficiaries pay approach which is used to allocate the costs of new, higher value and/or voltage regulated transmission investments in the economic (or market efficiency) category.
- Forecast benefits of investments in the economic category are modelled using comprehensive and detailed system planning software models. The modelling methods are resource-intensive and time-consuming.
- The beneficiaries pay approach is accepted in principle by most reasonable stakeholders and there have been relatively few disagreements resulting in legal challenge. Where challenge does arise, it tends to be where one or a very small number of parties were allocated all, or almost all, the costs of a high-value new investment.
- Efficiency benefits are realised through transparency with stakeholders: they know what costs they will be allocated through the beneficiaries pay approach and so are motivated to involve themselves in ensuring the right investment decision is made.

The study group also met with Professor Hogan in the United States, who made the following observations[33]:

- In implementing beneficiaries pay charging, Professor Hogan stressed the importance of making an ex ante cost allocation (e.g. based on a weighted average of forecast scenarios) and then keeping that allocation fixed indefinitely into the future.
- Even if circumstances changed ex post and the distribution of benefits ended up being different to the distribution that was originally forecast (and used for cost allocation), the beneficiaries pay charges should not be altered ex post. […] Firmly sticking to the ex-ante cost allocation, even though circumstances may change, is consistent with private sector investment planning in competitive markets.
- Investments that are categorised as “reliability” or “public policy” are able to be socialised, using a postage stamp approach[34]. Professor Hogan’s view, however, is that it is feasible to allocate the costs of all investments according to measured benefits and that this approach is preferable to postage stamping.

33 Ibid, paragraphs 5.13 and 5.14.

34 ‘Postage stamp’ is a method of cost sharing that ignores locational characteristics. The allocation to each region would be based on a measure of each region’s size, such as its maximum demand or load over a 12 month period.

4 Developing alternative pricing arrangements

This Chapter discusses the following questions that would need to be resolved in developing alternative pricing arrangements for interconnectors:

- Should the beneficiaries pay principle apply to all existing and new transmission investments?
- How should 'new interconnector projects' be defined?
- How should 'beneficiaries' be defined?
- Is it better to socialise the costs of new interconnectors through postage stamping?
- Should the allocation of costs to beneficiaries be revisited periodically?
- Who calculates the beneficiaries?
- How can project delays be avoided?

The purpose of this chapter is to discuss each of these questions and set out our views, drawing on the information presented in the previous two chapters.

Key messages

In our view, the pricing arrangements should be designed to reflect the following propositions:

- The beneficiaries pay principle should apply to 'new interconnector projects', where 'new' denotes projects that have not yet been commissioned.
- New interconnector projects should be defined to include the costs of supporting AC transmission investments, consistent with the RIT-T definition of the relevant project.
- The 'beneficiaries' should be the load customers in each region, consistent with the current Rules arrangements for recovering shared network costs from load customers.
- Postage stamping could be applied where the beneficiaries cannot be readily identified.
- The calculation of the beneficiaries should not be revisited, consistent with the practice in the United States.
- The project proponent should determine the beneficiaries as part of demonstrating the RIT-T process, which assesses the economic case for the proposed investment.
- Effective consultation and appropriately scoped dispute provisions would reduce the risk of project delay, whilst ensuring that the benefit assessment is fair and reasonable.

4.1 Should the beneficiaries pay principle apply to all existing and new transmission investments?

The evidence from the United States cautions strongly against applying the beneficiaries pay principle to existing assets. Whilst New Zealand is taking a contrary position, this approach is primarily to address the misallocation of the costs of the existing HVDC link between customers in the North and South islands. We are not aware of a similar concerns about historic interconnector investment in the NEM.

For the reasons outlined in section 2.3, our view is that any change to the current transmission pricing Rules should focus on 'new interconnector projects'. If the relevant RIT-T project includes supporting AC transmission investments, these assets should also be subject to the beneficiaries pay principle. In our view, the principal deficiencies in the Rules relate to treatment of new interconnector projects and, therefore, it is appropriate for any change in the current pricing approach to apply specifically to these investments.

4.2 How should new interconnector projects be defined?

If the scope of any change to the current pricing arrangements is to be limited to 'new interconnector projects', which would include supporting AC network augmentations as explained above, it is essential that these projects are defined unambiguously. One source of ambiguity is that some intra-regional investments remote from a regional boundary may improve the capacity of an existing interconnector.

To address this ambiguity, it is useful to note that the Rules currently provide the following definition:

> "**interconnection, interconnector, interconnect, interconnected** means a transmission line or group of transmission lines that connects the transmission networks in adjacent regions."

Therefore, whilst conceptually an intra-regional investment remote from a regional boundary may have the effect of increasing the capacity of an existing interconnector, it would not fall within the above definition of an 'interconnector' project. In our view, the 'beneficiaries pay' pricing provisions would only apply if:

- The project is subject to the RIT-T; and
- The project includes a transmission line or group of transmission lines that connects the transmission networks in adjacent regions.

For the avoidance of doubt, the beneficiaries pay principle would be applied to the full costs of the interconnector project as defined by the RIT-T, which would include any supporting AC transmission investments. The purpose of our proposed definition, therefore, is to exclude standalone intra-regional augmentations that are remote from a regional boundary, but to include intra-regional investments that form a component of an interconnector project. This approach is consistent with the concept of a 'RIT-T project' as specified in clause 5.16.3(e) of the Rules, which states that:

> "A RIT-T proponent must not treat different parts of an integrated solution to an identified need as distinct and separate options for the purposes of determining whether the regulatory investment test for transmission applies to each of those parts."

Any new Rule would also need to clarify what is meant by a 'new' interconnector project. In our view, a 'new' project could be defined as an interconnector project that is expected to be commissioned after the commencement of the new pricing arrangements. Savings and transitional provisions may apply if there are reasons to exclude particular projects from the new arrangements.

4.3 How should 'beneficiaries' be defined?

To give effect to the beneficiaries pay principle, it is necessary to define what we mean by 'beneficiaries'. Under the current Rules, the cost of shared transmission assets are paid entirely by load customers. In the context of interconnector projects, the beneficiaries pay principle is concerned with matching costs and benefits across the NEM regions. As load customers pay for the shared transmission network, this principle can only be achieved by also defining the beneficiaries as load customers in each region – otherwise there would be an inherent mismatch between those who benefit and those who pay.

The 'beneficiaries' would therefore be defined in terms of the benefits provided to customers in that region from the proposed project, expressed in net present value terms. Importantly, 'customer benefits' are different from the 'net market benefits' in the Rules. In particular, the focus will be on the benefits that customers obtain in each region, rather than the benefits to the NEM. We envisage that the 'customer benefits' may include:

- the expected change in wholesale generation prices;
- expected price reductions in ancillary services paid for by customers; and
- the expected improvements in supply reliability, valued at VCR.

We note that customer savings due to an expected change in wholesale generation prices are different to the savings in dispatch costs, which is identified in the RIT-T. In this analysis, our focus is not on the savings in dispatch costs, but rather the change in wholesale generation prices in each region as a result of the proposed interconnector project. This focus is appropriate because customers in each region will be rightly concerned with the impact on their electricity costs if the project proceeds (as opposed to the benefits to the NEM as a whole).

Under this approach, the AARR could be allocated on a pro rata basis, according to the expected customer benefit in each region (negative benefits would be set to zero). This method would ensure that the allocation of the AARR is not restricted to the two directly connected regions.

It is important to note that the AEMC has indicated that it may revisit the current transmission pricing arrangements in which only load customers pay for shared network assets. In particular, the AEMC makes the following comment in relation to future inter-regional transmission charging[35]:

> "…the final stage of the access reforms involve generators having the option to pay for transmission in return for firm access rights. This raises broader questions about the rest of the TUOS framework."

If the transmission charging framework changed so that generators were also regarded as 'beneficiaries', it would be reasonable to amend the calculation of 'beneficiaries' to capture benefits that accrue to the generation sector. However, given the current pricing arrangements, it appears logical to define 'beneficiaries' in terms of benefits to load customers only.

4.4 Is it better to socialise the cost of new interconnectors through postage stamping?

Under the approach described thus far, the calculation of 'beneficiaries' would require the project proponent to undertake additional modelling effort to identify the customer benefits in each region. Furthermore, we would expect extensive debate amongst stakeholders as to the calculation of the beneficiaries, particularly for large capital projects. In addition, the identification of the beneficiaries will be imprecise and will change over time in ways that cannot be forecast.

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[35] AEMC, Final Report, Final Report on the Coordination of Generation and Transmission Investment, page 104.

Given these difficulties, it could be argued that it is better to 'socialise' the costs of interconnectors across the NEM on a postage stamp basis (e.g. according to each region's peak demand or energy throughput), rather than undertaking analysis of the beneficiaries.

A degree of socialising is adopted in the US as part of the application of the beneficiaries pay principle. However, if costs are postage stamped the outcome will not be consistent with the beneficiaries pay principle. As a consequence, the deficiencies discussed in section 2.2 of this paper would not be addressed.

We therefore subscribe to the view expressed by Professor Hogan, who explains[36]:

> "A workable system of cost allocation commensurate with benefits for new transmission investment is within reach using available analytical tools. Cost allocation commensurate with the distribution of benefits follows directly from the information that must be produced as part of the evaluation of the investment.
>
> […]
>
> The procedures are not perfect, but they provide a workable approximation that makes transmission cost socialization a last, not a first, resort."

We agree strongly with the above observations and reiterate our support for a beneficiary pays allocation. We also recognise that there may be limited circumstances in which postage stamp may be appropriate – e.g. projects that are compliance obligations where jurisdictional benefits are not able to be calculated. However, the beneficiaries pay principle should form the basis of any new pricing arrangements.

4.5 Should the costs allocated to beneficiaries be revisited periodically?

The case for revisiting the calculation of the beneficiaries is that ex ante estimates over the life of an asset are highly likely to turn out to be incorrect. As already noted, the AEMC raised concerns regarding a fixed allocation of benefits[37]:

> *"The Commission's key concern with the particular beneficiary pays option that it considered in 2013 was that it locked in for perpetuity an initial estimate of benefit allocations. These predictions might well turn out to be wrong - and even perverse -*

36 William W. Hogan, Transmission Benefits and Cost Allocation, 31 May 2011, page 25.

37 Ibid, page 102.

from the viewpoint of future customers (given that transmission assets are paid off over 30 or 40 years)."

These concerns are undeniable, but it does not necessarily follow that:

- A beneficiaries pay approach should be avoided. The evidence provided in Chapter 3 shows that the US has successfully adopted this approach, whilst New Zealand is committed to its adoption. Furthermore, the alternative LRMC approach adopted in 2013 is not delivering pricing outcomes that are acceptable to customers.
- The calculation of beneficiaries should be revisited periodically.

In relation to the periodic re-evaluation of beneficiaries, it is useful to highlight the following commentary from Professor Hogan[38]:

> "In a sufficiently dense network, any attempt to estimate the benefits ex post, after a particular transmission expansion has been made, would be confounded by the daunting task of separating the network effects and reconstructing a counterfactual that identifies and removes all of the collateral investments in generation, load, and other transmission."

In other words, for an ex ante investment it is possible to examine the 'with' and 'without' cases by projecting forward from today, prior to the investment being made. However, if the same task is attempted in 10 years' time, for example, there is no longer a clear starting point for the 'without' investment case – as the investment has actually been in place for 10 years and other investment decisions have taken place as a result. It is therefore inherently difficult and contentious to recalculate the beneficiaries for an existing asset.

In the context of the National Electricity Objective, it is not clear why it is unacceptable to fix the beneficiary calculation at a point in time. This practice is adopted in the US and is also proposed in New Zealand. Furthermore, it is consistent with competitive market outcomes where parties may agree to share the costs of a large fixed investment based on expected future benefits, in the knowledge that the forecasts may turn out to be incorrect.

Given the above discussion, our view is that the calculation of the beneficiaries should not be revisited. However, we understand that some stakeholders may have an alternative view, particularly if the beneficiaries may change significantly over time.

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38 William W. Hogan, Transmission Benefits and Cost Allocation, Harvard University Cambridge, Massachusetts 02138, May 31, 2011, page 13.

4.6 Who determines the beneficiaries?

The current regulatory framework separates the investment decision through the RIT-T from the question of 'who pays'. In ordinary commercial situations, however, the question of whether to invest is considered alongside the question of who will pay for it. Our view is that the regulatory framework should mirror these normal commercial arrangements. If this view is accepted, it follows that the project proponent should determine the beneficiaries.

As noted in the US arrangements, it is important that the modelling is transparent, with adequate documentation provided to stakeholders to enable them to scrutinise the assessment. The calculation of the beneficiaries should also be subject to the existing dispute procedures in the RIT-T consultation process. The possibility of a dispute will ensure that the project proponent engages with stakeholders and explains its analysis from an early stage in the project evaluation process.

4.7 How can project delays be avoided?

Stakeholders may reasonably be concerned that the modelling to calculate the beneficiaries introduces the possibility of disputes that may lead to delays in commissioning much needed interconnector projects. The challenge, therefore, is to balance the interests of stakeholders in being able to challenge the beneficiary calculation against the need to avoid project delays.

In our view, this balance can be achieved through the following process:

- The benefit assessment should be conducted in parallel with the application of the RIT-T. As such, it should not extend the timeline for completing the RIT-T although it will require additional work by the project proponent.
- The risk of disputes may be reduced by the project proponent undertaking appropriate consultation and providing its modelling results to stakeholders.
- Disputes should only be permitted if it can be shown that the beneficiary calculation is either incorrect or unreasonable. A limited dispute provisions would reduce the risk of project delay, whilst ensuring that the assessment is reasonable.

5 A potential way forward

This Chapter provides a description of possible pricing changes that reflect the views we expressed in the previous chapter. Of course, we recognise that stakeholders will have a range of different views that would imply a different set of pricing arrangements. Nevertheless, the following description provides a potential starting point for these alternative views to be expressed.

The key elements of possible pricing changes are described below:

a. The RIT-T analysis that is conducted in relation to a new interconnector, including any supporting AC shared network augmentations, would be extended to identify the beneficiaries[39] in each NEM region. In particular, the Project Assessment Draft Report, which presents the results of the RIT-T cost benefit analysis, would be extended to require the RIT-T proponent to estimate the percentage share of the total customer benefits for each NEM region.

b. The customer benefits would be defined as the value of customer benefits over the expected life of the asset[40], which may arise from any estimated changes in:

    i) wholesale generation prices;

    ii) the prices paid for ancillary services; and

    iii) reliability

    expressed in present value terms.

    Items (i) and (ii) would be estimated having regard to the marginal costs of supply, whilst item (iii) would apply an estimate of the value of customer reliability. The details of the modelling would not be prescribed in the Rules, beyond a requirement that it must be reasonable and accompanied by an explanation of the modelling approach and results.

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39 As customers currently pay for shared network assets, beneficiaries should be defined as customers in order to give effect to the beneficiaries pay principle. In future, if generators contributed to shared network costs, then beneficiaries would be redefined accordingly.

40 It is reasonable to estimate this value by modelling the benefits over an appropriately long planning horizon, such as 20 years.

c. In its Project Assessment Draft Report, the interconnector proponent would propose the allocation of the interconnector's aggregate annual revenue requirement (including the revenue relating to any supporting AC shared network augmentation) between the NEM regions for the life of the asset. This would be in proportion to the percentage share of the total customer benefits as described above in a. and b. The RIT-T proponent may propose to postage stamp a portion of the project's annual revenue requirement across all NEM regions, but must explain why approach is expected to promote the achievement of the NEO.

d. The RIT-T proponent's proposed allocation of the aggregate annual revenue requirement between regions, including the portion of costs that are to be postage stamped, would be subject to the RIT-T consultation process. The proponent's modelling of the beneficiaries would be made publicly available.

e. The Project Assessment Conclusions Report, which is the final stage of the RIT-T process, would require the RIT-T proponent to address any submissions received in relation to the proposed allocation of the interconnector's aggregate annual revenue requirement between the NEM regions.

f. The existing dispute resolution procedures[41] that apply in relation to the Project Assessment Conclusions Report would be extended to include the calculation of the customer benefits and the proposed allocation of the project costs between the NEM regions (which will include any postage stamped component). As a result, the AER would determine the allocation of the interconnector project's aggregate annual revenue requirement (including the revenue relating to any supporting AC shared network augmentation) between regions in the event of a dispute.

g. The arrangements described above would only apply to new interconnector projects. Existing interconnectors would therefore be unaffected by the proposed arrangements. Any future application of the MLEC (or a revised MLEC) would not apply to new interconnector assets[42], but would apply to existing regulated transmission assets including existing regulated interconnectors.

h. The transmission pricing provisions in Part J of Chapter 6A would be amended to recognise the interconnector charges that would apply as a result of the customer benefit assessment. This approach is consistent with the principle that the total costs

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[41] Clause 5.16.5.

[42] This outcome could be achieved by setting the flow on new interconnectors to zero for the purpose of the MLEC calculations.

of the project should be shared across the NEM regions in accordance with customer benefits.

i. The Modified Load Export Charge would be amended so that it does not apply to new interconnector projects that are subject to interconnector charges based on customer benefits.

j. It should be noted that Rule changes would not be required in relation to the regulatory investment test or the AER's RIT-T guidelines. We recognise, however, that the AER may wish to issue separate guidance on how the beneficiaries pays assessment should be conducted by the RIT-T proponent.

k. Savings and transitional provisions would need to be drafted to ensure that the proposed provisions are implemented appropriately given that interconnector projects are at different stages of the RIT-T process.