Transmission Pricing Methodology Review: LRMC charges

Working paper

Discussion paper

29 July 2014

Market Design

1 Executive summary

Introduction

1.1 The Electricity Authority (Authority) is conducting a review of the Transmission Pricing Methodology (TPM) in schedule 12.4 of the Electricity Industry Participation Code 2010 (Code). The Authority is developing its response to submissions and cross-submissions in relation to the consultation paper 'Transmission Pricing Methodology: issues and proposal' dated 10 October 2012 (October 2012 issues paper) and to points raised in the May 2013 TPM conference.

1.2 Prior to developing a second issues paper, the Authority is developing and considering key aspects of a revised TPM proposal through a series of working papers. This working paper examines whether the use of long-run marginal cost (LRMC) -based transmission charges ("LRMC charges") to recover the costs of high voltage direct current (HVDC) and interconnection assets would better promote the Authority's statutory objective than maintaining the status quo.

1.3 Unlike the beneficiaries-pay working paper, this working paper does not model specific LRMC charge options. If, after considering submissions on this working paper, the Authority decides to further investigate LRMC charge options, the Authority will prepare a further working paper presenting modelling of specific LRMC charge options. If the Authority decides to propose an LRMC charge in the second issues paper (whether alongside a beneficiaries-pay option or otherwise) a specific proposal would be provided in the second issues paper together with a detailed cost-benefit analysis of the proposal relative to the status quo.

Some submissions suggested LRMC charges are more efficient than beneficiaries pay charges so should be investigated further

1.4 The beneficiaries-pay working paper noted that charges based on the LRMC of transmission would provide efficient price signals about the cost of transmission investment. However, the paper suggested that the 'loop flow' characteristics of the interconnected grid, combined with the large number of parties using the grid, made it impracticable to apply LRMC charges. The Authority therefore considered that a beneficiaries-pay approach is the next best option in terms of efficiency and practicality.

1.5 Several submissions on the beneficiaries-pay working paper considered the Authority should investigate LRMC charges. Submitters considered that:

(a) LRMC charges were more preferred under the Authority's decision-making and economic framework for the TPM and would better promote the Authority's statutory objective than other options the Authority had favoured such as beneficiaries-pay charges

(b) The reasons that the Authority had advanced for not investigating LRMC charges further were not valid as the SPD charge indicated practical difficulties such as dealing with loop flows and large number of grid users under LRMC could be readily overcome

(c) Practical methods of applying LRMC charges had been identified earlier in the review, such as the tilted postage stamp, and LRMC charges could also be readily applied by other means such as modifications to the status quo and the Authority's zonal SPD charge proposal. The Commerce Commission's application of total service long-run incremental cost (TSLRIC) charges to telecommunications may provide insights to the application of LRMC charges

(d) The Authority should investigate and model LRMC charge options as it has done with beneficiaries-pay charge options.

LRMC charges are market-like and so are more preferred under the TPM decision-making and economic framework

1.6 LRMC is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand. LRMC charges are market-like and are therefore, in principle, more preferred under the Authority's decision-making and economic framework. Peak period prices equal LRMC in workably competitive markets where fixed costs are somewhat large, thus promoting efficient investment. Thus, market-like prices in the TPM would involve setting prices for peak demand periods equal to LRMC.

1.7 Technological change (which is likely to lead to a reduction in costs over time), regulatory change (which may change the costs that can be recovered), and the difficulty of setting peak period prices equal to the cost of changing the capacity of the grid to meet customer demand, mean LRMC charges are unlikely to fully recover historical costs. A charging approach that is less preferred under the Authority's decision-making and economic framework may therefore be required to recover remaining costs. Since the costs to be recovered do not involve externalities, the next-most preferred charging approach is beneficiaries-pay and, if necessary, a residual charge.

1.8 If a beneficiaries-pay charge were applied in combination with LRMC charges the nature of price signals provided by the beneficiaries-pay charge would need to be considered — in particular, how those price signals would affect the price signals from the LRMC charge.

1.9 LRMC charging requires a means of accurately estimating LRMC. Since LRMC is the cost of future investments to meet future changes in demand this means forecasts would be required of:

(a) future demand

(b) the future transmission investment required to meet expected future demand.

1.10 A methodology would also be required to calculate LRMC. There are three main methodologies for calculating LRMC:

(a) marginal incremental cost (MIC), which considers how future costs will change as a result of a permanent change in demand

(b) average incremental cost (AIC), which calculates the additional capital and operating expenditure over the planning period required to meet a permanent increase in demand (over and above forecast increases in demand) for the planning period

(c) long-run incremental cost (LRIC), which calculates the annualised cost of the next proposed investment and divides this by the permanent increment in demand.

1.11 The MIC approach to estimating LRMC is the approach most consistent with providing efficient price signals, but is likely to result in volatile transmission charges. Other approaches, such as AIC and LRIC, are approximations of the MIC approach, and provide price signals that are less efficient than the MIC approach, but deliver more stable transmission charges.

Potential LRMC charge options were considered by Electricity Commission and TPAG and could be considered further

1.12 Options for LRMC charging have been considered earlier in the TPM review by both the Commission and TPAG, including tilted postage stamp, bespoke locational preferences, and LRMC charging applied using load flow analysis. This investigation was to varying levels of detail. None of the options considered appear to have been rejected for reasons that suggest that they would fail to promote the Authority's objectives for the TPM, which is to promote efficient operation and investment in the electricity industry for the long-term benefit of consumers. Accordingly, if LRMC charges are considered further following this working paper, the options considered previously could be considered again in subsequent analysis.

Experience from LRMC charging in other jurisdictions may be relevant

1.13 LRMC charges, referred to as Transmission Network Use of System (TNUoS) charges, have been applied in the United Kingdom (UK) except Northern Ireland (see below). However, unlike New Zealand, the UK does not have nodal pricing in their wholesale electricity markets (which provides price signals that reflect at least the short-run marginal cost (SRMC) of transmission). Nevertheless, the UK experience is relevant as the rationale for their LRMC charges is promotion of efficient investment.

1.14 The UK LRMC charges are calculated using a DC load flow transport model. In essence, the methodology estimates the increase or decrease in units of kilometres (km) of the UK transmission system required as a result of an additional 1 MW injection to the system. Charges are split between generation and demand (27% and 73% respectively) and are levied according to peak winter generation or demand.

1.15 The Republic of Ireland and Northern Ireland recently introduced an all-island Generator Transmission Use-of-System (GTUoS) charge, which may also be relevant to the TPM review. Load flow analysis is used to determine network requirements 5 years into the future and to allocate the costs of the necessary network augmentation to generators. Once an asset has been built its cost continues to contribute to the GTUoS charge for up to an additional seven years. This method therefore applies charges based on the estimated investment costs of meeting future demand. It also applies charges to parties that the load flow analysis indicates as benefiting from investments after they are made. This charge can therefore be considered a mix of LRMC charging and beneficiaries-pay.

1.16 The Australian Electricity Market Commission (AEMC) has proposed requiring distributors to set network tariffs on the basis of the LRMC of providing network services.[1] Although distribution networks do not have the same degree of loop flows or economies of scale as transmission networks, and nor is their use subject to nodal pricing, the AEMC's consideration of LRMC charges may be relevant to the TPM review.

Practicability issues with LRMC charging are considerable

1.17 There are a number of practicability issues that would need to be addressed before applying an LRMC charge. On a technical level these include:

(a) the definition of LRMC to be used

(b) the methodology used for calculating LRMC – MIC, AIC, LRIC or another methodology

(c) the appropriate approach for forecasting demand for transmission services to be used for calculating LRMC

(d) the appropriate approach for forecasting the transmission investments required to meet the forecast demand for calculating LRMC

(e) depending on the methodology chosen, the forecasting period used to calculate LRMC charges

(f) whether LRMC charges would be made at a nodal or zonal level

[1] AEMC, Consultation paper: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 14 November 2013.

(g) how LRMC charges at a node or zone would be calculated. The UK TNUoS charge uses load flow analysis to calculate LRMC charges. The Authority has investigated the load flow analysis used to calculate the TNUoS charges, and its preliminary view is that a similar approach could be utilised in New Zealand, though with some changes

(h) whether adjustments should be made for the signals provided by nodal pricing

(i) determining the parties to be subject to LRMC charges

(j) the basis for applying LRMC charges, including whether this should be on:

   (i) peaks or congestion and what would constitute a peak or congestion for charging

   (ii) on a capacity or energy basis, and how this would be set.

1.18 In addition to those technical issues there are regulatory issues about whether the LRMC approach in practice provides perverse price signals and whether it would be sustainable over time. In particular:

(a) LRMC charges provide price signals based on investments that are expected to occur in the (distant) future. The LRMC charges for each investment reduce to zero when the new asset is commissioned. Once a party is charged for future investments they would appear to have perverse incentives to push for those investments to occur as soon as possible so as to reduce their charges to a minimum. To the extent that adjustments to timing of investments are not reflected in LRMC charges, LRMC charges would encourage inefficient timing of investment. Having a charging basis such as beneficiaries pay applying following commissioning of investments would counteract this effect.

(b) An LRMC charging regime may be unsustainable as parties would be paying for assets/services that don't yet exist and, as noted in (a) above, the charges are unstable at the point of investment. There is also the issue of whether the regulator can reasonably assess the accuracy of the forecasts of demand and transmission investments. Those forecasts are likely to change over time, and new investment and technology options will arise over time. These issues lead the Authority to question whether the charging regime will be sufficiently robust over time to be sustainable.

1.19 The Authority notes that these practicability issues are considerable and, to the extent they can be resolved, significant time would be required. The Authority would welcome submitters' views on whether these issues can be readily addressed.

1.20 if LRMC charges were applied but did not fully recover Transpower's, costs the Authority's decision-making and economic framework implies a beneficiaries-pay charge should be applied to recover remaining costs. The combination of LRMC and beneficiaries-pay charges, and possibly residual charges, would be more complex than the status quo.

1.21 The design of the charges, including if necessary a residual charge, would need to ensure the price signals provided were efficient.

LRMC charges lawful and could provide net benefits relative to status quo

1.22 The use of LRMC charges would be lawful.

1.23 A quantified CBA would be required to determine whether LRMC charges would provide net benefits relative to the status quo. The Authority's preliminary assessment is that LRMC charges could provide net benefits relative to the status quo. A final assessment would depend on whether the potential efficiency improvements resulting from LRMC charges would occur in practice under a regulated regime, and if so, whether they would outweigh the significant implementation, operational and other costs of applying those charges.

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Background to process

2.1 The Electricity Authority (Authority) is reviewing the transmission pricing methodology (TPM), which specifies the method for Transpower New Zealand Limited (Transpower) to recover costs of operating, maintaining, upgrading and extending the transmission grid.

2.2 The Authority considers that the current TPM can be improved so as to better meet the Authority's statutory objective of promoting competition in, reliable supply by, and the efficient operation of, the electricity industry for the long-term benefit of consumers.

Working papers

2.3 The Authority has decided to advance the process of reviewing the TPM by developing a second TPM issues paper (second issues paper) following consideration of submissions on the October 2012 TPM issues paper (October issues paper) and information provided at the TPM conference held in Wellington on 29-31 May 2013.

2.4 Prior to developing a second issues paper, the Authority is developing and further considering key aspects of a revised TPM proposal through a series of working papers, which will provide key inputs into the second issues paper.

Background to this working paper

2.5 Following consideration of submissions on the October issues paper, the responses of parties to the Authority's questions at the May 2013 TPM conference, and submissions on the beneficiaries-pay and other working papers, the Authority decided to prepare a working paper to better understand whether transmission charges based on the long-run marginal cost (LRMC) would provide net benefits.

Purpose of this working paper

2.6 The purpose of this working paper is to assist the Authority to understand whether LRMC-based transmission charges (LRMC charges) would better promote the Authority’s statutory objective than:

(a) maintaining the status quo or

(b) implementing charging approaches that the Authority has previously proposed – in particular, beneficiaries-pay charges.

2.7 The Authority would appreciate feedback on whether LRMC charges would better promote the Authority's statutory objective than the status quo or beneficiaries-pay charges, and whether LRMC charges should be investigated further. In particular, the Authority seeks feedback on whether LRMC charges could be designed that:

(a) would provide sufficiently accurate price signals to promote efficient operation of, and investment in, the electricity industry

(b) would complement the signals provided by nodal pricing on the wholesale market

(c) would be practicable within a regulatory environment.

2.8 Unlike the beneficiaries-pay working paper, this working paper does not model specific LRMC charge options. If, after considering feedback on this working paper, the Authority is of the view that LRMC options should be investigated further, the Authority will prepare a further working paper presenting and modelling specific options for LRMC charges. If the Authority decides to propose an LRMC charge in the second issues paper (whether alongside a beneficiaries-pay option or otherwise) a specific proposal would be provided in the second issues paper together with a detailed cost-benefit analysis of the proposal.

Other working papers

2.9 Other working papers the Authority has completed or will complete include:

(a) Cost benefit analysis (CBA) – This paper outlined a revised approach that the Authority intends to apply to the cost-benefit analysis of a revised TPM proposal that will be included in the second issues paper. (Submissions closed)

(b) Definition of sunk costs – This paper examined the extent to which the costs involved in the provision of electricity transmission services are actually "sunk" and the implications for transmission pricing. (Submissions closed)

(c) Avoided cost of transmission (ACOT) – This paper considered the efficiency implications of changes to the TPM that may reduce the quantum of ACOT payments, assuming the current ACOT payment policies are maintained. (Submissions closed)

(d) Use of loss and constraint excess (LCE) to offset transmission charges – This paper explored submitter suggestions that the proposed use of LCE to offset transmission charges would distort the otherwise efficient wholesale market signals. (Submissions closed)

(e) Beneficiaries-pay approach – This paper examined options for applying a beneficiaries-pay charge. (Submissions closed)

(f) Connection charges - This paper examines whether the pool charging approach for transmission connection assets is efficient and whether there is potential for connection assets to be inefficiently classified as interconnection assets. (Submissions closed)

(g) Problem definition – This paper will discuss and, where possible, quantify problems with the current TPM. It will build on the problem definition provided in the October 2012 issues paper. (To be released)

(h) Approach to residual charge - This paper will consider the most efficient approach to residual charges, including whether it may be efficient to levy any residual charge on the basis of congestion rather than load during peak demand periods. (To be released)

2.10 As stated in paragraph 2.8 above, the Authority may release a further working paper to examine options for applying an LRMC charge, depending on the Authority's analysis of feedback on this working paper.

Decisions on the TPM

2.11 Section 32(1) of the Electricity Industry Act 2010 (Act) requires that provisions in the Electricity Industry Participation Code 2010 (Code) must be consistent with the Authority's statutory objective.

2.12 The TPM is part of the Code, so any provision or amendment to the TPM must be consistent with the Authority's statutory objective.

2.13 In order to assist the Authority to make decisions about the TPM consistent with its statutory objective the Authority developed a decision-making and economic framework[2]. The Authority applied this framework to derive the proposal for the TPM that is set out in the October issues paper[3]. After considering submissions on the October issues paper and parties' responses to the Authority's questions at the May 2013 TPM conference, the Authority has decided to develop and release a second issues paper. This will include a revised TPM proposal and draft guidelines (as referred to in clause 12.89 of the Code) to be followed by Transpower in developing a new TPM.

2.14 In developing the second issues paper, the Authority will continue to be guided in its decisions by its TPM decision-making and economic framework.

2.15 The Authority will make decisions about the development of the TPM according to its Code amendment principles and the Authority's statutory objective.

2.16 The Authority's Consultation Charter[4] sets out guidelines relating to the processes for amending the Code and the Code amendment principles that the Authority will adhere to when considering Code amendments.

2 Available from http://www.ea.govt.nz/our-work/programmes/priority-projects/transmission-pricing-review/.

3 Available from http://www.ea.govt.nz/our-work/consultations/priority-projects/tpm-issues-oct12/.

4 Available from http://www.ea.govt.nz/about-us/documents-publications/foundation-documents/.

3 Submissions on this working paper

3.1 The purpose of this paper is to consult with participants and persons that the Authority thinks are representative of the interests of persons likely to be substantially affected by the TPM.

3.2 The Authority's preference is to receive submissions in electronic format (Microsoft Word). It is not necessary to send hard copies of submissions to the Authority, unless it is not possible to do so electronically. Submissions in electronic form should be emailed to submissions@ea.govt.nz with *Working Paper – Transmission pricing methodology: LRMC charges* in the subject line.

3.3 If submitters do not wish to send their submission electronically, they should post one hard copy of their submission to the address below.

Submissions
Electricity Authority
PO Box 10041
Wellington 6143

3.4 Submissions should be received by 5pm on 23 September 2014. Please note that late submissions are unlikely to be considered.

3.5 The Authority will acknowledge receipt of all submissions electronically. Please contact the Submissions Administrator if you do not receive electronic acknowledgement of your submission within two business days.

3.6 Your submission is likely to be made available to the general public on the Authority's website. Submitters should indicate any documents attached, in support of the submission, in a covering letter and clearly indicate any information that is provided to the Authority on a confidential basis. However, all information provided to the Authority is subject to the Official Information Act 1982.

4 Beneficiaries-pay submissions indicate the Authority should consider LRMC charges further

Discussion of LRMC charges in beneficiaries-pay working paper

4.1 The beneficiaries-pay working paper noted that charges based on the LRMC of transmission would provide efficient price signals about the cost of transmission investment. It noted that the LRMC of transmission can be defined as the capital and operating costs that would be incurred to increase transmission capacity by one unit. The beneficiaries-pay working paper noted charges based on LRMC could promote dynamic efficiency if such charges ensured that:

(a) consumers and producers face price signals that ensure they take into account the cost of transmission investment when making their own investment decisions. This includes investment decisions in relation to:

(i) expansion

(ii) location

(iii) innovation

(b) the transmission provider would face a price signal to only add capacity when consumers of transmission services are willing to pay for it.

4.2 The beneficiaries-pay working paper suggested that the 'loop flow' characteristics of the interconnected grid combined with the large number of parties using the grid makes it impracticable to adopt an administrative approach of calculating the LRMC of transmission for each user and setting transmission prices on that basis. The Authority therefore considered that a beneficiaries-pay approach is the next best option in terms of efficiency and practicality.

4.3 The working paper acknowledged that setting prices according to incremental benefit at best only approximates efficient signals since prices are unlikely to reflect LRMC. However, the Authority considered that, in the absence of a mechanism that produces prices that reflect LRMC, benefit-based charges are likely to be the most efficient means of promoting dynamic efficiency.

Discussion of LRMC charges in beneficiaries-pay working paper

4.4 Submissions were received on the TPM beneficiaries-pay working paper on 25 May 2014.

4.5 Some parties submitted that the Authority should investigate LRMC options. The main points submitters made on LRMC charges in submissions on the beneficiaries-pay working paper and the Authority's response are set out in Table 1 below.

Table 1: Submitter comments on LRMC based charges and Authority response

	Submitter comment	Action
1	"An LRMC charge would provide transmission users with price signals that approximate the long run costs of their transmission usage at peak times. This is desirable from a dynamic efficiency perspective to inform transmission users' (including consumers') decisions on the usage of the transmission system and their investment in alternatives (including for example in distributed generation)."[5]	The Authority agrees that in principle an LRMC charge could promote dynamic efficiency for these reasons. This paper examines whether an efficient LRMC charge would occur in practice and whether it would be practicable within a regulatory environment.
2	"…a charge that approximates LRMC over extended periods of time (it need not be perfect) is likely to be more efficient than no such charge, or one that reflects some other economic concept (such as the level of private benefit)."[6]	In principle, the Authority agrees that an efficient LRMC charge is likely to be more efficient than a beneficiaries-pay charge. Whether a charge that approximates LRMC is more efficient than a beneficiaries-pay charge depends on the degree of approximation. Ultimately, this is an empirical question, and depends on the design details of the charges. But, more fundamentally, the Authority questions whether LRMC charges would provide perverse price signals and be unsustainable.
3	The Authority should consider introduction of more LRMC-like signals. Some of those options may involve only modest refinements of the current TPM.[7]	This working paper considers whether LRMC charges should be considered in more detail. If the Authority concludes that LRMC charges should be investigated further, the Authority will then consider options for an LRMC charge. While the existing TPM could be used as the basis for design of an LRMC charge, e.g.

5 Electricity Networks Association (ENA), paragraph 46, page 14.

6 ENA, paragraph 53, page 15.

7 Transpower, page 10.

		applying transmission charges to the current transmission charging regions according to the national LRMC or the LRMC for each region, such a change is unlikely to involve only "modest refinements" of the TPM. This is because the changes required would be material, e.g. even if LRMC charges were applied using an estimate of a national LRMC the charge would be likely to vary between regions because of differing investment requirements in different regions. It would also be necessary to determine whether LRMC charges should apply to the same parties as those subject to interconnection charges, or not.
4	"…estimating the LRMC for the interconnection service is not straightforward and would involve judgements arising from the meshed nature of the system. …the challenges of a meshed grid arise for both [the SPD method and LRMC], and it is not clear why the Authority perceives the LRMC method insurmountable but the SPD method not so."[8]	The Authority agrees that it is necessary to deal with the challenges of a meshed grid in the case of both the SPD method and LRMC charges. However, the SPD model is designed to deal with the meshed grid so does not require further modification, whereas the Authority has not identified an equivalent approach for applying LRMC charges. As noted below, simplifications may be available that allow application of LRMC charges that work around the problem of a meshed grid. The key question with such approaches is whether this produces reasonably efficient charges.
5	"While we are sceptical about the merit of LRMC pricing, we question whether the BPO Working Paper's reasons for rejecting LRMC are valid. We doubt LRMC pricing would be as complex as [the] SPD method, the difficulties arising from the meshed nature of the interconnection network do not	This paper examines in more detail the reasons put forward in the beneficiaries-pay working paper querying the practicability of LRMC charges. The Authority agrees that the zonal SPD charge option does illustrate a potential approach for applying

8 ENA, paragraph 50, page 14.

	apply to the HVDC link and, regardless, the Authority's zonal pricing option shows how the meshed nature of the interconnection network can be addressed."[9] "The Tilted Postage Stamp also provides an example of how simplified LRMC pricing could be introduced. This suggests LRMC pricing is probably practical."[10]	an LRMC charge to the meshed grid. However, as with the zonal SPD charge, such a design involves compromises in terms of the accuracy of the price signal provided relative to a charge calculated and applied at a nodal level. The key question would be whether this provides net benefits relative to the status quo and relative to other alternatives. The tilted postage stamp may also indicate how simplified LRMC pricing could be introduced. Relative to using the zonal SPD charge approach to applying an LRMC charge, the tilted postage stamp is likely to involve greater compromises in terms of the accuracy of the price signal provided. Unless it is lower cost to implement than a zonal approach, the less accurate price signal means it is unlikely to provide greater net benefits than a zonal approach, although it may provide greater net benefits than the status quo.
6	"Given this new investment [Transpower's recent investment programme] is now effectively sunk the most efficient approach to transmission pricing is likely to be to focus on static efficiency and optimal utilisation of the existing grid (rather than be dedicated to avoidance of the need for further investment). This is supported by the various quantitative analyses of the impact of locational/LRMC pricing [footnote reference to Appendix C: Validating the stage 2 conclusions on the benefits of location-based price signals for economic transmission investment,	The relevance of sunk costs to transmission pricing is considered in the sunk costs working paper, and the Authority has still to consider submissions on this paper. However, just because the recent investment programme is almost complete does not mean that more efficient outcomes are not possible from transmission pricing that better reflects the costs of future transmission investment. Demand for transmission investment can change over time, so more efficient outcomes may be possible from

9 Transpower, page 9.

10 Transpower, footnote 7, page 9.

	TPAG [Transmission Pricing Advisory Group], Transmission pricing discussion paper, 7 June 2011]".[11]	transmission pricing that reflects the future transmission costs required to meet future changes in demand. The Authority notes that the Electricity Commission's modelling of locational transmission pricing suggested net benefits of $0 to $30m, although this benefit was within the model's margin of error. However, this modelling only assessed the benefits from applying locational transmission pricing to generators in relation to 'economic' investments[12]. The Commission did identify that there were benefits from providing location signals in relation to 'reliability investments. [13] These account for the bulk of transmission investment. Further, the modelling assumed that a reduction in total system costs equated to the total benefit that could be obtained from locational transmission pricing. However, changes in system costs have flow-on economic effects that also need to be considered.
7	The Commerce Commission's application of the Total Service Long Run Incremental Cost (TSLRIC) method to estimating the costs to Chorus Ltd of supplying unbundled copper loop and unbundled bit-stream access would provide insights relevant to estimating the LRMC for interconnection capacity.[14]	As discussed later in this paper, one method of applying LRMC charges would be to base charges on LRIC. The Authority agrees that the Commission's application of TSLRIC may provide insight into the application of LRMC charges to transmission, although notes that loop flows in particular are less of an issue for applying cost-based charges to telecommunications than they are for transmission.

11 Transpower, page 16.

12 'Economic' transmission investments are investments seek to lower the costs of generation.

13 'Reliability' investments are transmission investments that seek to improve the reliability of electricity supply.

14 ENA, paragraph 51, pages14-15.

8	The Authority should explore possible ways of estimating LRMC for the interconnection service and publish the results, as it has done with the SPD method.[15]	Methods for estimating LRMC for interconnection and the HVDC are discussed in this paper. The Authority will consider whether to model LRMC charges after considering submissions on this working paper.
9	The Authority should consider a TPM that provides LRMC price signals to the extent possible, and use beneficiaries-pay or RCPD/I charges (or some combination) to recover any residual interconnection (IC) revenue requirement.[16]	The possibility of a TPM based on LRMC charges is considered in this working paper. The Authority has been considering beneficiaries-pay charges because of their potential to promote more efficient investment. LRMC charges are potentially a more efficient alternative for achieving this objective. If LRMC charges were applied there may be residual costs to recover. If, after considering feedback on this working paper, the Authority decides to investigate LRMC charges further, the Authority will consider the appropriate approach to recovering any residual costs under an LRMC charge in the residual charge working paper.
10	"The 2012 Framework Paper identifies five options for pricing methodologies under exacerbator pays (including the kvar charge). The remaining four options were: two variations on LRIC [long-run incremental cost] (one involving a contract, one not), a 'tilted postage stamp' based on the LRMC of expanding grid capacity in a region, and a peak charge based on LRMC. These options are all worthy of further consideration and	The Authority is investigating LRMC charges in this paper because, as discussed below, such charges may be considered market-like under the Authority's TPM decision-making and economic framework, and therefore are in principle more preferred under the framework than beneficiaries-pay charges. As was explained in the October 2012 TPM issues paper (2012

15 ENA, paragraph 53, page 15.

16 ENA, paragraph 10, pages 2-3.

	as they are higher on the Authority's Framework hierarchy, when using that Framework they should be given priority over beneficiaries-pay options."[17]	issues paper), exacerbators-pay charging is the appropriate approach to address externalities, such as the reactive power issue that the kvar charge seeks to address.[18] The economic problem that is the focus of this working paper is not addressing an externality but how to ensure decisions about demand for transmission services fully take into account the transmission cost implications of that demand. This means that, if applied, LRMC charges would be applied to all demand for transmission services, not just exacerbators, as would be appropriate under exacerbators-pay. That said, the four options identified (two variations on LRIC, tilted postage stamp, and a peak charge based on LRMC) are all possible approaches for applying LRMC charges, and are discussed in this working paper.
11	"The 2012 Framework Paper recognises "it would be important to ensure that the [LRMC] charge would be passed on in a manner that provided a price signal so that exacerbators faced the cost of their exacerbating activity". This suggests that a demand-based charge should be structured as a capacity charge, preferably for peak periods, as that would best reflect the usage that drives the need for incremental transmission capacity."[19]	As noted above, the Authority is considering LRMC charges as they are a market-like charge rather than because an externality has been identified, which would require exacerbators-pay charging to be considered. That said, If LRMC charges were applied, it may be appropriate to structure such charges as capacity charges for the reasons identified.
12	"… LRMC can be expected to be lower than average total costs due	As noted above, the Authority acknowledges that if LRMC

17 ENA, paragraph 55, page 16.

18 See the explanation of exacerbators pay in Transmission Pricing Methodology: issues and proposal, 10 October 2012, paragraphs 3.3.9-3.3.11, page 41.

19 ENA, paragraph 57, page 16.

	to the relatively large fixed costs (that don't scale with capacity) of establishing the transmission grid. This suggests that a residual charge would be required, as is the case in most of the options that the Authority is currently considering. Thus an LRMC charge should not be discarded for this reason."[20]	charging were applied a residual charge may be required. The Authority agrees that this does not mean LRMC charges should not be considered. The key question is whether LRMC charges combined with any other charges required would best promote efficiency relative to the status quo and other transmission charging options.

Source: Electricity Authority

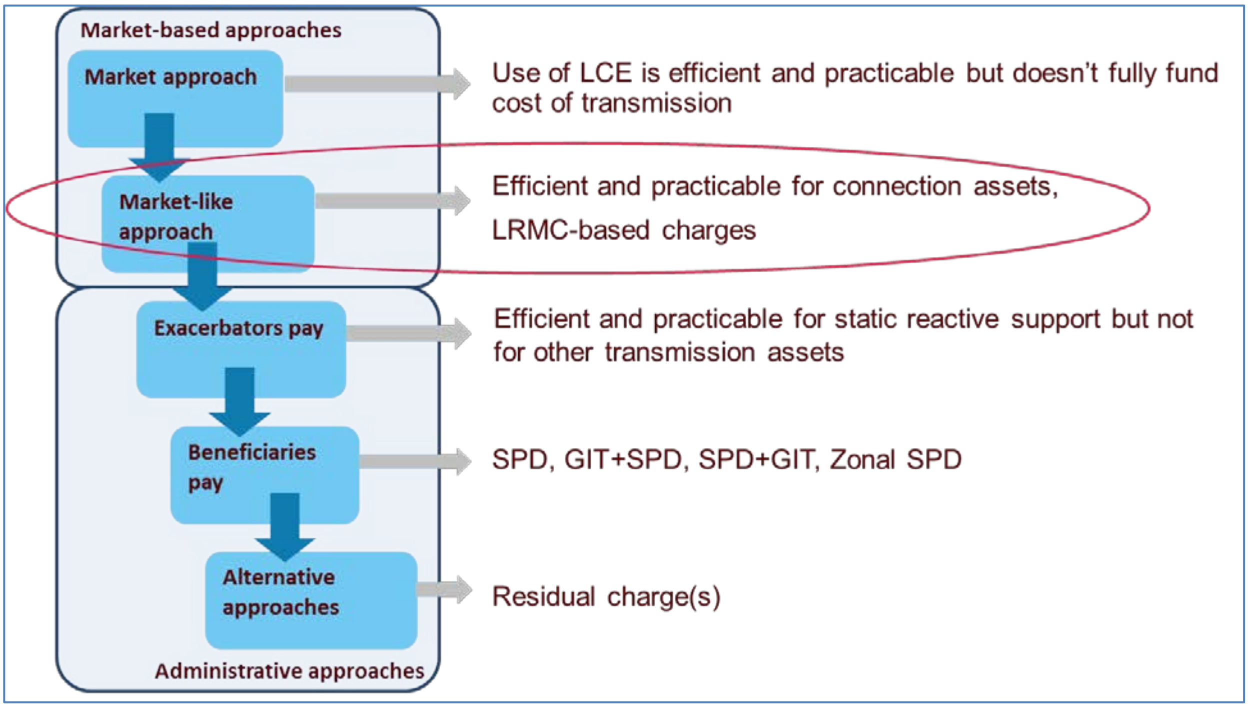
[20] ENA, paragraph 58, page 16.

5 Efficient LRMC charge preferable under decision-making and economic framework

The place of LRMC charges in the Authority's decision-making and economic framework

5.1 As illustrated in Figure 1, LRMC charges are market-like and therefore more preferred than beneficiaries-pay charges under the Authority's decision-making and economic framework for transmission pricing.

Figure 1: Position of LRMC charges in Authority's decision-making and economic framework



5.2 To understand the place of LRMC charges in the economic framework, and why LRMC charges are more efficient than beneficiaries-pay charges, requires considering the circumstances in which each charging approach may be appropriate.

5.3 Transmission has particular characteristics that also influence the approach to transmission charging: large fixed costs (in other words, the extent of economies of scale and scope) and loop flow effects.

5.4 Under the framework, market pricing is most preferred. Market pricing achieves perfectly efficient outcomes when:

(a) prices equal short-run marginal cost (SRMC) at times when there is spare capacity and equal LRMC when capacity has to be rationed among users. These prices would achieve efficient use of the grid

(b) differences in prices across the grid reflect cost differences for the grid, so that grid users locate away from the lowest cost area only when their nongrid costs justify doing so. These price differences would achieve efficient location decisions by generation and load

(c) competing grid companies have incentives to expand the grid only when grid users value the additional grid services by more than the cost of grid expansion (LRMC). This achieves efficient investment in the grid.

Pricing in workably competitive markets produces prices broadly reflective of SRMC and LRMC

5.5 No market is perfectly competitive, but many markets are workably competitive, for example airlines, insurance, and mobile telephony. In a market like airlines, there are no loop flow effects and fixed costs are somewhat large but not so large that it is inefficient to have multiple competing providers.

5.6 As fixed costs are somewhat large, it is not profitable for potential entrants to enter the market whenever prices exceed SRMC during off-peak periods and LRMC during peak periods (and by that action push prices down to SRMC and LRMC). Likewise, large fixed costs mean that incumbents do not quickly exit the market when prices are below SRMC and LRMC.

5.7 Nevertheless, in those markets prices broadly reflect SRMC during off-peak demand and LRMC during peak demand, and competition provides strong incentives for suppliers to carefully evaluate the net benefits of expanding or contracting capacity. The cost of poor investment decisions generally resides with the investor.[21]

5.8 Since such prices promote broadly efficient outcomes, and regulatory intervention has minimal chances of doing any better, the best approach in the case of workably competitive markets is to rely on the market to set prices.

If grid services were priced as in workably competitive markets, prices would reflect SRMC during off-peak periods and LRMC during peaks

5.9 In the case of the interconnected grid, there are both loop flow effects and very large fixed costs relative to the size of the market. The loop flow effects mean it is not straightforward to assess the extent to which a permanent increment or decrement in demand or generation at a node increases or decreases capacity requirements across the grid. The very high fixed costs of grid capacity expansion and contraction mean it is efficient to have only one party providing the services - a monopoly.

5.10 As monopolies have incentives to set prices above both SRMC and LRMC, pricing of interconnected grid services (grid services) is usually regulated.

21 The main exception to this result is if all firms in the market simultaneously over- or under- estimate future demand for their services. In this case, firms and consumers share the costs of poorly-timed investment decisions, and their share of those costs depends on relative price elasticities of demand and supply.

5.11 As in other situations where LRMC substantially exceeds SRMC, setting prices for grid services to SRMC would substantially under-recover costs. However, the *operation* of grid services is priced using a workably competitive spot market in which nodal prices reflect SRMC of transmission.[22] This both solves loop flow effects and promotes efficient operation of the grid. Nodal prices are set using a market, and so nodal pricing is a market approach.

5.12 Nodal pricing based on SRMC creates a surplus of funds called loss and constraint excess (LCE). However, since nodal prices reflect SRMC rather than LRMC, the LCE is insufficient to fully recover the fixed costs of providing grid services.

5.13 Because grid services are a monopoly, the market cannot be relied on to efficiently price grid services to recover fixed costs. Accordingly, at least a market-like approach is required. Regulation could seek to set prices equivalent to those seen in workably competitive markets – that is, pricing would utilise a market-like approach.

5.14 As has been seen, peak period prices equal LRMC in workably competitive markets where fixed costs are somewhat large, thus promoting efficient investment. Thus, market-like prices in the TPM would involve setting prices for peak demand periods equal to LRMC.

5.15 LRMC charging requires a means of accurately estimating LRMC. LRMC is forward looking, as it is the cost of future changes in capacity of the grid to meet future changes in demand. LRMC charging therefore requires a forecast of the future transmission investment required to meet expected future demand. Decisions would need to be made about the inputs to the forecast and whether the forecast was determined by Transpower or a regulator. This question is discussed in more detail in Section 8, which discusses the practicability of LRMC charging.

5.16 In addition to an investment forecast, a methodology to calculate LRMC would need to be determined. The main methodologies used to calculate LRMC – marginal incremental cost (MIC), long-run incremental cost (LRIC), and average incremental cost (AIC) – are discussed in Section 5.

Other charges may be required with LRMC charges to fully recover costs

5.17 As in workably competitive markets, technology and regulatory changes mean there is no reason to expect LRMC charges to always fully recover historical

[22] When there are no binding constraints, differences in nodal prices across the grid reflect the marginal losses of transmitting electricity from one node to other nodes. This calculation corresponds easily to the concept of SRMC. When there is a binding constraint the differences in nodal prices reflect the higher prices bid by generation and dispatchable demand downstream of the constraint versus those upstream of the constraint. SRMC in this case is best thought of as the short-run marginal opportunity cost (SRMOC) of operating the grid.

costs.[23] Moreover, it will not be possible to set peak period prices exactly equal to the cost of changing the capacity of the grid to meet customer demand. Both factors mean that other charges may be required. Further, if regulation allows the grid provider to fully recover its costs, as is the case for Transpower, other charges may be needed to address any shortfall in cost-recovery from LRMC charges.

Beneficiaries-pay pricing would be next preferred if LRMC charging is impracticable

5.18 If regulatory or technical factors (such as loop-flow effects or an inability to accurately forecast future transmission costs) mean LRMC charging is impracticable or inefficient, or if LRMC charging would be efficient but does not fully recover costs, the next relevant approach under the hierarchy of the framework is beneficiaries-pay. (As explained in section 3, the reason for this is exacerbators-pay charging is appropriate in order to address an externality, and changing the network to meet future demand is not addressing an externality.[24])

5.19 Provided charges do not exceed a customer's private benefit, and provided they are set in a manner that does not induce the customer to alter their behaviour in an attempt to understate their actual benefit, beneficiaries-pay charges should promote efficient use and operation of the grid.

5.20 Beneficiaries-pay charges do not reflect LRMC. A beneficiaries-pay charge would therefore be less successful than a theoretically efficient LRMC charge at promoting efficient investment. (However, as discussed elsewhere in this paper, practicability issues with LRMC charges may mean beneficiaries-pay charges are superior at promoting efficient investment in practice.) However, since beneficiaries would know that under beneficiaries-pay charging they are responsible for contributing to the costs of future transmission investments, they would have strong incentives to ensure transmission investments are efficient.[25] Accordingly, beneficiaries-pay charging would help to promote efficient transmission investment.

5.21 Similarly, beneficiaries would have strong incentives to consider the transmission cost implications of their own investment and location decisions, which would help to promote efficient investment in the electricity industry.

5.22 If a beneficiaries-pay charge were applied in combination with LRMC charges the nature of price signals provided by the beneficiaries-pay charge would need to be

[23] The reasons why technological change may mean LRMC charges do fully recover historical costs are discussed in detail in paragraphs 8.30 – 8.36 below. Regulatory change may prevent LRMC charges from fully recovering historical costs as it may affect the costs that can be recovered.

[24] See *supra* note 18.

[25] At least in the sense that they have strong incentives to resist transmission investments that involve costs that would result in charges to them that exceed their private benefits.

considered — in particular, how those price signals would affect the price signals from the LRMC charge.

5.23 Beneficiaries-pay charges may involve a residual where the costs of investments exceed aggregate private benefit or where the costs are not covered by the charge (for example because the investments are too small). Therefore, the need for the residual charge to send price signals to promote efficient investment will depend on the extent to which the beneficiaries-pay charge is likely to promote efficient investment and the extent of coverage of the charge.

6 Application of LRMC charges

What is an LRMC charge?

6.1 All LRMC charges are based on estimating changes in the future cost of a good or service that are expected to arise from permanent increments or decrements in current and future demand for the good or service. Hence, LRMC charges are forward-looking and do not take into account costs already incurred to produce and deliver the existing level of goods and services.

6.2 LRMC includes all changes to costs arising from altering supply to meet current and future changes to demand. By contrast SRMC are just the additional costs involved in increasing or decreasing supply when there is no expansion or contraction in capacity. In other words, SRMC excludes the costs of investment or divestment.

6.3 In principle, prices based on LRMC should only be charged on peak demand and prices during off-peak periods should reflect SRMC. This reflects that it is generally efficient for firms to make capacity expansion and contraction decisions based on the profits they expect to earn during peak demand periods. Note that LRMC is very low when peak demand is much less than capacity. This is because future investments are not required for a considerable period of time in these situations.

6.4 However, regardless of the industry under consideration, setting LRMC charges on peak demand can result in under- or over recovery of historical costs. For example:

(a) under-recovery will occur when advances in technology reduce LRMC, which means LRMC (and therefore prices charged) is below the average cost of providing existing services. In workably competitive markets firms write down the value of their existing assets.

(b) in workably competitive markets, under-recovery may occur when a more efficient competitor enters the market so incumbents are no longer able to sustain charges that fully recover historical costs.

(c) over-recovery of costs occurs when regulations increase the LRMC of new supply. In this case LRMC (and therefore prices charged) exceeds the average cost of providing existing services, and asset owners in workably competitive markets book capital gains on their existing assets.

(d) LRMC can increase for non-regulatory reasons, resulting in over-recovery of historical costs, such as in natural resource industries where the cheapest resources are exploited first. In this case, LRMC increases until large technical innovations disruptively reduce the cost of resource extraction, as has recently occurred with the technology for accessing shale gas.

Methodologies for calculating LRMC charges

6.5 There are three main methodologies for calculating LRMC: marginal incremental cost (MIC), average incremental cost (AIC), and long-run incremental cost (LRIC) approaches. These three methodologies are explained below. An illustrative example of application of the three methodologies is provided in Appendix A.

6.6 Estimation for LRMC requires estimating both the marginal capital costs (MCC) and the marginal operating costs (MOC) associated with bringing forward investment projects.

The MIC approach (most efficient)

6.7 The MIC approach[26] considers how future costs will change as a result of a permanent change in demand. In essence, the methodology takes account of the fact that capital investment may be required at some time in the future due to on-going growth in demand. Hence, permanent increments in demand over and above these projections bring forward the timing of investments. The capital component of the MIC approach measures the discounted value of the additional capital costs from bringing forward the investment, rather than the capital costs of the investment. The discounted value of these costs increases as the period for making the investment draws nearer.

6.8 As noted in a paper on LRMC charges prepared by Marsden Jacobs Associates for the Queensland Competition Authority, the MIC methodology may be summarised as follows:

(a) “forecast the relevant expected demand into the foreseeable future

(b) estimate the system requirements and augmentations that would be required over time to meet expected demand levels

(c) estimate the likely cost of these requirements

(d) adjust the demand upwards by an increment

(e) reconsider the system requirements and augmentations that would be required to meet this new demand pattern and associated costs

(f) calculate the MCC as the difference between the net present values of the investment program(s) divided by the total increase in demand.”[27]

6.9 The formula for MIC MCC is as follows:[28]

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26 The MIC approach is also referred to as the “perturbation” approach or “Turvey” approach after Professor Ralph Turvey who developed the MIC approach. See Turvey, R, What are marginal costs and how to estimate them? Centre for the Study of Regulated Industries, University of Bath School of Management Technical Paper 13.

27 Marsden Jacob Associates, Estimation of Long Run Marginal Cost (LRMC), A report prepared by Marsden Jacob Associates for the Queensland Competition Authority, 3 November 2004, page 11.

28 This formula is a corrected version of the formula for MIC from Marsden Jacob Associates, *op. cit*. The formulae that follow are also from this report. This report provides more formal versions of the formulae for MIC, AIC and LRIC and further background on applying LRMC charging.

$$MIC_t^{MCC} = \frac{NPV_t(capex_j) - NPV_t(capex_{j+1})}{\Delta demand}$$

where

t = year for which MIC is being calculated

$NPV_t(capex_j)$, $NPV_{t+1}(capex_{j+1})$ are the net present value (NPV) of capital expenditure (capex) in years j and $j+1$ respectively, where year j is the year in which the next large investment expenditure takes place or the year in which the system reaches capacity

$\Delta\ demand$ is the change in demand between t and $t+k,$ where $k > j$.

6.10 The formula for MIC MOC is as follows:

$$MIC_t^{MOC} = \frac{\Delta opex}{\Delta demand}$$

or the change in operating expenditure (opex) to meet the changing demand.

6.11 The MIC approach produces estimates of LRMC that rise as spare capacity reduces up to a maximum LRMC where the capacity expansion occurs. Once the new investment is made the LRMC falls to its minimum, from which point the LRMC/price gradually rises as spare capacity falls. In other words, the MIC definition does not “look” beyond the next capacity expansion, and so ignores the effect on unit costs of subsequent increases in output.

6.12 Because the formula only considers the next capacity expansion this method produces prices that have a “saw-tooth” pattern, as illustrated in Figure 4 of Appendix A. Given the large fixed costs of transmission, this means that there are likely to be significant differences between the prices when investment to meet increased demand is imminent, and when the investment has just been made. That is, the MIC approach results in volatile transmission prices, in the same way that nodal pricing does.

6.13 This volatility differs to some extent from the outcomes of a workably competitive market. Fixed costs are not so large in a workably competitive market and so the saw-tooth effect would be much more moderate. Firms in workably competitive markets negotiate long-term supply agreements with their permanent customers, often with smoothed prices applying.[29]

6.14 The MIC approach to estimating LRMC is the approach most consistent with providing efficient price signals. Other approaches, such as AIC and LRIC, are approximations of the MIC approach and provide price signals that are less efficient than the MIC approach.

29 For example, airlines often adopt smoothed or long-term prices for transporting regular commercial cargo. Airline passengers, however, often have irregular demand for airline services and so they often experience saw-tooth price effects as airline routes swing from substantial spare capacity to limited capacity.

6.15 The Transmission Network Use of System (TNUoS) charges applied in the United Kingdom are a form of LRMC charges applied using a method that reflects the MIC approach.

The average incremental cost (AIC) approach

6.16 The average incremental cost (AIC) approach calculates the additional capital and operating expenditure over the planning period required to meet a permanent increase in demand (over and above forecast increases in demand) for the planning period.[30] The AIC approach then divides the increased capex and opex by the total increase in demand to derive a value for AIC.

6.17 The Marsden Jacobs Associates report referred to above summarises the AIC methodology as follows:

(a) "forecast the relevant expected demand characteristics into the foreseeable future

(b) estimate system requirements and augmentations that would be required over time to meet expected demand levels

(c) estimate the likely cost of these requirements

(d) calculate the MCC as the average cost per unit of anticipated demand of the total increment to capacity required [for] the forecast period."[31]

6.18 The formula for AIC MCC is as follows

$$AIC_t^{MCC} = \frac{NPV(Capex)}{NPV(Demand)}$$

6.19 The formula for AIC MOC is:

$$AIC_t^{MOC} = \frac{NPV(opex)}{NPV(demand)}$$

6.20 Calculation of AIC is in contrast to the MIC approach which just looks at the next increment in capital and operating expenditure required to meet the next increment in demand.

6.21 This means AIC produces a much smoother price over time than MIC since the cost is the average over the series of investments and operating expenditure required to meet future demand, as illustrated in Figure 2 of Appendix A. Accordingly, the price produced by AIC mimics to some extent the relatively smooth long-term contract prices that often occur in workably competitive markets.

[30] Hence it omits capex and opex that would occur without the permanent increment in demand.

[31] Marsden Jacobs Associates, *op. cit.*, page 13.

The long run incremental cost (LRIC) approach

6.22 The long run incremental cost (LRIC) approach calculates the annualised cost of the next proposed investment and divides this by the permanent increment in demand.[32]

6.23 The formula for LRIC MCC is as follows:[33]

$$LRIC_t^{MCC} = \frac{Annuitised\ capex}{\Delta demand}$$

6.24 The formula for LRIC MOC is the same as for MIC MOC defined above.

6.25 LRIC produces a constant price for the period until the next investment. When the new investment is made, the LRIC will produce a new price based on the next investment after the investment that has just been made. This means that LRIC produces a stable price between investments but then changes as new investments are made. This is illustrated in Figure 3 of Appendix A.

6.26 The LRIC approach has a number of variations. It could be calculated on the next series of investments, or it could be calculated based on the series of investments to provide a particular service (called total service long run incremental cost, or TSLRIC) or a particular element of a service (called TELRIC).

6.27 As noted in the beneficiaries-pay working paper[34] and the ENA's submission to that working paper[35], a variation on the LRIC approach, TSLRIC, is used by the Commerce Commission to set regulated prices for telecommunications services. The distribution network in the UK, at least, also uses the LRIC method for setting charges. [36] However, as noted by Ekins (2011), "its use in transmission may be problematic because the uncertainties in the assumptions that have to be made about demand growth and the likely pattern of generation"[37].

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32 Description from AEMC, Consultation Paper, National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 14 November 2013, page 58.

33 The form of LRIC shown in the formula is sometimes referred to as "Textbook LRIC".

34 Transmission pricing methodology review: Beneficiaries-pay options, Working paper, paragraph 5.16, page 12.

35 ENA, *supra* note 16.

36 Ekins, P, Ofgem's Project Transmit, A peer review of commissioned academic analysis, UCL Energy Institute, University College of London, 17 June 2011, page 8. This report may be found at: https://www.ofgem.gov.uk/publications-and-updates/project-transmit-peer-review-commissioned-academic-analysis

37 *Ibid.*

7 Implications of previous investigation of LRMC charging and overseas experience

Previous investigation of LRMC charges was not definitive

7.1 Some LRMC charging options for New Zealand were investigated in stages 1 and 2 of the TPM review by the Electricity Commission. Two main options were developed in detail – tilted postage stamp and bespoke locational preferences.[38] Those options involved setting charges based on LRMC on a locational basis at a relatively aggregated level, but with charges adjusted for the price signals provided by nodal pricing.

7.2 Commission staff undertook modelling to examine whether there were benefits from introducing locational signals in relation to 'economic' transmission investments.[39] This analysis suggested there was "limited value in providing for an enhanced locational signal to generators to ensure co-optimisation of economic transmission investments and generation"[40].

7.3 Commission analysis did identify, however, that there were likely to be benefits from introducing further locational signalling of reliability investments.[41]

7.4 The Commission rejected further consideration of the tilted postage stamp option "due to the likely lack of benefit from setting such charges across the market and the additional complexity of setting market-wide charges compared to a narrower bespoke version"[42].

7.5 The Commission considered a bespoke locational preferences option, bespoke postage stamping, should be investigated further. However, TPAG decided not to do this but to investigate shallower or deeper connection instead. This was because TPAG considered "there was little benefit in pursuing the bespoke pricing options identified in stage 2, as the existing RCPD interconnection charges already provide a signal for demand management in regions with growing net demand as compared to regions where growing net demand is not anticipated. The grid investment process includes a transmission alternative regime with similarities to some variants of the bespoke pricing option. In the TPAG's assessment introducing other general/specific bespoke transmission pricing options is unlikely to provide additional benefits, and risks conflicts with the existing RCPD mechanism."[43]

38 See Electricity Commission, Transmission Pricing Review: Stage 2 options, July 2010.

39 Electricity Commission, Transmission Pricing Review: Stage 2 options, Appendix 3: Analysis of the potential benefits of locational signalling for economic transmission investment, July 2010.

40 Electricity Commission, Transmission Pricing Review: Stage 2 options, July 2010, paragraph 13, page C.

41 *Ibid.*

42 *Ibid.*, paragraph 4.1.8.

43 TPAG, Transmission pricing discussion paper, 7 June 2011, paragraph 5.1.9, pages 37-38.

7.6 The conclusion that there may be benefits from introducing further locational signalling in relation to reliability investments but not economic investments was criticised by an independent review of TPAG's analysis by Dr Darryl Biggar.[44] The reviewer's main concerns were that some key assumptions in the modelling drove the results in a way that would understate any benefits from further locational signalling in relation to economic investments and that, anyway, the distinction between economic and reliability benefits was artificial.

7.7 In addition to the tilted postage stamp and bespoke locational preferences, the Commission examined another option that could have involved LRMC charging: load flow analysis – in particular, investment cost-related pricing (ICRP).[45] This is the approach used by National Grid to calculate the TNUoS charges mentioned in section 6 and discussed further below. ICRP uses a direct current (DC) load flow transport model to calculate the marginal costs of investment in the transmission system required as a consequence of an increase in demand or generation at each connection point. As noted in section 6, ICRP may be considered as an application of the MIC method.

7.8 While the Commission considered that load flow options should be considered further its main focus was on the use of load flow analysis to apply beneficiaries-pay charges.[46] The TPAG decision to "consider options for shallower or deeper allocation of costs to specific participants rather than 'providing incentives for participants to take action to defer or avoid investments where there are benefits in doing so'"[47] meant load flow approaches that involved LRMC charging, such as ICRP, were not investigated further. Instead, TPAG only investigated the use of load flow techniques to apply beneficiaries-pay charges.

7.9 In conclusion, while some options for LRMC charging have been considered earlier in the TPM review by both the Commission and TPAG, this has been to varying levels of detail. None of the options considered appear to have been rejected because they would fail to promote the Authority's objectives for the TPM, which is to promote efficient operation and investment in the electricity industry for the long-term benefit of consumers. Accordingly, those options could be considered again in more detail in subsequent analysis.

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44 Biggar, D, Independent Review of "Transmission Pricing Advisory Group: Transmission Pricing Discussion Paper: 7 June 2011", prepared for the New Zealand Electricity Authority, final report, 30 June 2011.

45 Electricity Commission, Transmission Pricing Review: Stage 2 options, Appendix 2: Further analysis including consideration of stage 1 submissions and assessment of high level options, July 2010, section 5.5, pages 61-66.

46 See Electricity Commission, *supra* note 39, paragraphs 4.2-4.16, pages 44-46.

47 TPAG, *ibid*., paragraph 7.2.5, page 83.

Experience from other jurisdictions

Application of LRMC charging in UK potentially relevant even though UK does not have nodal pricing

7.10 As noted in the previous section, LRMC charges have been applied in the UK except Northern Ireland (see below). However, unlike New Zealand, the UK does not have nodal pricing in their wholesale electricity markets (which, as noted previously, provides price signals that reflect at least the SRMC of transmission). Nevertheless, the UK experience is potentially relevant as the rationale for their LRMC charges is promotion of efficient investment,[48] which is a key focus of the Authority's TPM review. Other charges are applied that seek to provide the price signals provided by nodal pricing in New Zealand.[49]

7.11 As noted in the previous section, TNUoS charges in the UK are calculated using a DC load flow transport model. In essence, the methodology estimates the increase or decrease in units of kilometres (km) of the UK transmission system required as a result of a 1 MW injection to the system. This calculation is conducted at each connection point or node on the system, based on a study of peak conditions on the system.[50] However, to ensure that charges are relatively stable and administratively simple, charges are calculated on a zonal basis rather than a nodal basis.[51]

7.12 TNUoS charges are split between generation and demand 27% and 73% respectively. Recently National Grid has proposed changing this split to, for example, 15% to generation and 85% to load, as the current split puts UK generation at a disadvantage to competing generators elsewhere in Europe who are not subject to equivalent charges.[52]

7.13 TNUoS charges are levied according to generation or demand by half-hourly metered consumers during the three half hours of peak electricity demand between the beginning of November and the end of February each financial year. TNUoS charges for non-half hourly metered consumers are levied according to average annual consumption between the hours of 5pm and 7pm. In other words, TNUoS charges are levied on the basis of generation or demand during peaks.

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48 For example, as noted by National Grid: "The underlying rationale behind Transmission Network Use of System charges is that efficient economic signals are provided to Users when services are priced to reflect the incremental costs of supplying them. Therefore, charges should reflect the impact that Users of the transmission system at different locations would have on the Transmission Owner's costs, if they were to increase or decrease their use of the respective systems. These costs are primarily defined as the investment costs in the transmission system, maintenance of the transmission system and maintaining a system capable of providing a secure bulk supply of energy." National Grid, Connection and Use of System Code, Section 14, Charging Methodologies, v1.6, 12 March 2014, paragraph 14.14.6, page 32. This document can be found at: http://www2.nationalgrid.com/uk/industry-information/electricity-codes/cusc/the-cusc/

49 In particular, the Balancing Services Use of System (BSUoS) charges. See National Grid, *ibid.,* Section 2.

50 For a detailed explanation of the calculation of the UK TNUoS charges see National Grid, *ibid.,* sub-sections 14.14-14.15, pages 31-53.

51 *Ibid.,* paragraph 14.15.30, page 39.

52 National Grid, Modification Proposal - CMP227 'Reduce to GD split of TNUoS charges for example to 15-85' - updated version. This document can be found at: http://www2.nationalgrid.com/UK/Industry-information/Electricity-codes/CUSC/Modifications/CMP227/

All-island charges to generators in Ireland and Northern Ireland may be relevant - combination of LRMC and beneficiaries-pay charging

7.14 The all-island Generator Transmission Use-of-System (GTUoS) charge recently introduced in the Republic of Ireland and Northern Ireland may also be relevant to the TPM review.[53] This charge is similar to the UK TNUoS charge though is just charged to generation. Load flow analysis is used to determine network requirements five years into the future and to allocate the costs of the necessary network augmentation to generators, although the charges are based on current generation meeting the current demand. Once an asset has been built its cost continues to contribute to the GTUoS charge for up to an additional seven years. (This is unlike a 'pure' LRMC charge where, once an asset has been built, the charge is based on the cost of the next investment(s)). In other words, this charge is a mix of LRMC charging and beneficiaries-pay (based on load flow analysis), as it is both forward-looking and backward-looking.

Australian Electricity Market Commission proposal for distribution pricing suggests LRMC charges could be practicable

7.15 The Australian Electricity Market Commission (AEMC) has proposed requiring distributors to set network tariffs on the basis of the LRMC of providing network services.[54] Although distribution networks do not have the same degree of loop flows or economies of scale as transmission networks, and nor is their use subject to nodal pricing, the AEMC's consideration of LRMC charges may be relevant to the TPM review.

7.16 The AEMC proposal indicates that there are three main elements that would need to be considered in the implementation of LRMC charging:

(a) the definition of LRMC. The AEMC suggested using the following definition: "the present value cost of bringing forward network capital and operating costs to meet a particular user's sustained incremental derived demand for the relevant network service"[55]

(b) the methodology used for calculating LRMC

(c) the detailed implementation and application of LRMC.

7.17 As the AEMC paper indicates, these are matters that have been given extensive consideration in the literature and at a practical level. Accordingly, while there is likely to be debate about the correct approach to each of these elements, the AEMC paper suggests that LRMC charging is likely to be practicable for

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53 See in particular Commission for Energy Regulation/Utility Regulatory, Single Electricity Market, Generator Transmission Use of System Charging Decision paper, 29 September, 2011 SEM-11-078. This document can be found at: http://www.allislandproject.org/GetAttachment.aspx?id=91fcf973-e74f-438d-8f08-d951dd0df291

54 AEMC, Consultation paper: National Electricity Amendment (Distribution Network Pricing Arrangements) Rule 2014, 14 November 2013.

55 *Ibid.,* page 58.

distribution services at least. Since distribution services do not involve as significant loop flow effects as transmission, further work would be required to determine whether LRMC charges are practicable.

7.18 The AEMC paper notes that LRMC charges are unlikely to recover the total costs of the network so a residual charge or charges is likely to be required.

8 Practical application of LRMC charges

Accuracy of LRMC charges depend on accuracy of forecasts of demand and supply

8.1 A key issue with applying LRMC charging mechanisms through regulation is accurately estimating LRMC. LRMC is forward looking, as it is the cost of future augmentation of the grid to meet future changes in demand. Accordingly, regardless of the methodology used for calculation of LRMC, applying LRMC charges would require forecasts of:

(a) demand for transmission services

(b) the transmission investment required to meet the forecast demand.

8.2 This means LRMC charges would be based on judgement.

8.3 Regarding forecasting demand, the demand forecasts used to determine Transpower's individual price-quality path (IPP) under Part 4 of the Commerce Act could be used. This would mean LRMC charges would be based on near-term demand estimates and the transmission investment implied by those estimates.

8.4 There are some potential issues from taking this approach, however. For example, if the demand estimates used to set LRMC charges do not reflect actual long-term demand then LRMC charges could over- or under-signal the costs of future transmission investment. In turn, this could lead to lesser or greater demand for transmission services than is efficient.

8.5 Regarding forecast transmission investment, Transpower, as a monopoly, may have incentives to overstate the transmission investment required to meet a given level of demand. Since regulators have less information than a grid owner on the actual investment required to meet forecast demand, regulators may not be in a strong position to challenge the capex assumptions that would be used to set LRMC charges. This means there may be a risk that LRMC charges set through regulation would be based on over-estimates of LRMC, so consumers of transmission services would be over-charged.

8.6 However, provided consumers of transmission services are responsive to transmission prices, this risk is potentially self-correcting. This is because LRMC charges based on over-estimates of LRMC would reduce demand for transmission services, thereby delaying and/or reducing the need for transmission investment. The extent of self-correction would, however, depend on how responsive consumers of transmission services are to transmission prices. It would also depend on the extent to which the transmission investment forecast used to calculate the charges reflects the transmission investment that would actually be made.

Methods are available that mean loop flows do not prevent calculation of LRMC charges

8.7 As noted in section 4, the beneficiaries-pay working paper suggested that the 'loop flow' characteristics of the interconnected grid combined with the large number of parties using the grid makes it impracticable to apply LRMC charges. However, further investigation of this issue suggests loop flows would not prevent the calculation of LRMC charges.

8.8 As noted in section 7, the UK TNUoS charge uses load flow analysis to calculate LRMC charges.[56] The Authority has investigated the load flow analysis used to calculate the TNUoS charges, and its preliminary view is that a similar approach could be utilised in New Zealand, though with some changes.

8.9 A load flow perturbation analysis, similar to the TNUoS method, could be performed on future peak demand scenarios such as those developed in Transpower's Annual Planning Report (APR). Each scenario typically consists of a time series of load flow cases with incremental planned transmission and generation builds into the future. A load flow perturbation routine could be applied to each of those load flow cases to calculate transmission asset incremental "usage" matrices. With transmission cost estimates from the APR, two nodal cost vectors (demand and generation) could be calculated for every future load flow in the scenario. Those future annual nodal cost vectors could then be brought forward to a present value nodal LRMC vector and divided by peak demand to form a $/MW indicator.

8.10 One key technical problem is how to perform the perturbation analysis in terms of how to allocate the "slack" or reference bus. All load flows have what is termed a slack or reference bus. This is used to "take up the slack" when generation and demand are out of balance. When adding a demand or generator perturbation, the slack bus will simply increase or decrease to balance the system. Therefore the selection of the slack bus can be very important when calculating the change in power flow on a transmission asset. One way to overcome this unwanted effect is to perform a smart iterative load flow solution that for each perturbation scales all generation or demand across the country, adjusting the HVDC link accordingly so that there is no change in both the NI and SI slack buses. For example, a 1MW demand increase at OTA2201 might cause all generators to be collectively scaled up by 1.12MW with the HVDC increasing in northwards flow by 0.71MW (numbers made up).

If LRMC charges were applied, should they be adjusted to reflect the signals provided by nodal pricing?

8.11 Some authors, such as Associate Professor James Bushnell of the University of California, Davis, who provided advice to Trustpower on the beneficiaries-pay

56 National Grid, Connection and Use of System Code, Section 14, Charging Methodologies, v1.6, 12 March 2014, paragraph 14.15.21-14.15.23, pages 38-39.

working paper, suggest that nodal pricing is all that is required to promote efficient investment in relation to transmission.[57] This appears to be based on a view that nodal pricing provides price signals that reflect both the SRMC and the LRMC for transmission. However, nodal pricing is likely to result in price signals systematically below LRMC for the following reasons:

(a) the SRMC of the use of the transmission network is signalled through differences in nodal prices – but if spot prices do not reflect the true value to customers of lost load, price differences will at best send a muted signal of the true marginal cost of the transmission network. While scarcity pricing has been introduced in New Zealand, its application is limited to separate scarcity prices for the North and South Island, so the value of lost load at a more disaggregated level is still not priced. This means within-island price differences, at least, send a muted price signal below the true marginal cost of the network

(b) transmission planners err on the side of caution in determining the transmission capacity required to meet future demand

(c) the grid reliability standards (e.g. the N-1 standard for the core grid) are independent of economic costs. To the extent the core grid extends to remote locations, the same reliability standards are applied to remote and centrally located customers

(d) lack of competition may lead to overbuilding transmission in an attempt to address competition problems

(e) over-building of transmission may be justified for reasons of national security

(f) economies of scale in transmission mean transmission is commonly overbuilt, and the amount by which overbuilding reduces SRMC below LRMC is considerable. This means it is impossible to match transmission capacity precisely with transmission requirements at all times.[58]

8.12 Since most of these reasons apply in New Zealand nodal prices are likely to under-signal LRMC so LRMC charges could potentially promote more efficient investment. However, while LRMC charges may be appropriate, nodal pricing will still provide some signal of marginal cost, albeit muted. For example, current nodal prices provide a price signal which means generators generally receive, and load generally pays, a higher price the further north they are located. Similarly, nodal prices generally mean that generators receive, and load pays, a

57 See Bushnell, J, Efficiency and cost recovery for transmission network investments, Department of Economics, University of California, Davis, March 2014. Appendix to Trustpower submission: TPM – beneficiaries-pay working paper, 25 March 2014.

58 This list is adapted from NERA Economic Consulting, New Zealand Transmission Pricing Project, A report for the New Zealand Electricity Industry Steering Group, page 40. NERA state the list is based on H. Fraser, Can FERC's standard market design work in large RTOs?, Electricity Journal, Volume 15, Number 6, July 2002, page 25.

higher price downstream of a constraint and a lower price upstream of a constraint.

8.13 For this reason, it may be appropriate to adjust LRMC charges to take into account the signals provided by nodal prices. This was the approach taken by NERA with their proposal for a tilted postage stamp. For the tilted postage stamp proposal, which would have been applied on a zonal basis, the charges would have been set by:

(a) calculating the average historical nodal price differentials between zones (and, since the tilted postage stamp proposal applied only to generators, ignoring rentals since generators do not receive them) over as long a period as possible

(b) for each zone, deducting the average nodal price differentials (ie the SRMC signal) from the estimated LRMC.[59]

8.14 However, it is important to recognise that the need to adjust LRMC charges would depend on how LRMC charges are calculated. For example, if it were decided to adopt the UK approach of levying LRMC charges according to generation or demand during just the 3 highest peaks,[60] LRMC charges would need to take into account average nodal price differences for the peak periods used to calculate the charge.

If LRMC charges were applied, should they be applied on the basis of peaks or congestion?

8.15 As noted in section 5, LRMC relates to the cost of changes to capacity to meet changes in demand, and so LRMC charges are usually levied on the basis of peak demand. However, as discussed at the May 2013 TPM conference, the need to expand capacity may not be driven by peak demand but by congestion.[61] Peak demand is when demand is highest regardless of whether capacity is being fully utilised, whereas congestion is when capacity is closest to being fully utilised. Peak demand will not necessarily coincide with congestion.

8.16 To understand this issue, consider the example of demand for buses. When the demand for buses is at its peak there may still be spare capacity on some buses – that is, spare seats. This means that if bus fares were charged according to peak use some travellers may decide not to use the bus even if there were spare seats available, which would be inefficient. If, however, buses were charged according to the degree of congestion travellers would be incentivised to only avoid use of the bus when there were no seats available, which would be more efficient. The same logic applies to the transmission system: it is likely to only be

59 *Ibid.,* page 75.

60 Note that if it were decided to apply LRMC charges the question of the number of peaks used to determine LRMC charges would be a matter for Transpower to consider when designing the new TPM.

61 See for example question by Chair, TPM conference transcript, 30 May 2013, page 229-230

efficient to disincentivise use of the network through transmission charges when there is congestion in the network rather than when use of the network is at its peak when there may or may not be spare capacity.

8.17 Of course, nodal pricing already provides a price signal in relation to congestion. However, for the reasons noted above this price signal is unlikely to reflect the LRMC of transmission. Further, for LRMC charges to provide efficient investment signals, it may be efficient to apply charges both when constraints are close to binding as well as when they actually bind. Therefore high nodal prices or significant price differences (as occurs when constraints bind) are not necessarily the right indicators to use to apply LRMC charges.

8.18 One approach the Authority has identified for applying a congestion-based charge is the "saturation ratio", which can be defined as the ratio of the flow on a line relative to the capacity of the line. When the flow equals capacity the saturation ratio will equal 1 and when there is no flow the saturation ratio will equal zero.

8.19 Therefore, rather than charging according to peaks, charges could be applied when the saturation ratio is at a level that indicates congestion is either imminent (above a threshold ratio) or is occurring (i.e. equal to or greater than 1). Alternatively, charges could be applied in a similar way to the current peak charges: for those periods when the saturation ratio is highest. Either approach has the potential to provide a more targeted LRMC charge than charging according to peaks alone.

If LRMC charges were applied, should they be charged on a capacity or energy basis?

8.20 The purpose of an LRMC charge would be to signal to consumers of transmission services the long-run cost implications of their demand for transmission services in order to promote efficient investment. It would therefore be likely to be efficient to charge according to the factor that determines the size of transmission investment needed to meet that demand: the capacity of the equipment used by consumers of transmission services.

8.21 In the UK TNUoS charges to generation and half hourly metered demand are on the basis of capacity (generation and demand in kW during peaks, although one element of the TNUoS charge to generators, the local substation tariff, is charged according to the substation's voltage and total MW throughput). Non-metered load is charged on an energy basis - average annual consumption between the hours of 5pm and 7pm, as noted in section 7.

8.22 GTUoS charges in Ireland and Northern Ireland are charged according to each generator's maximum export capacity.

8.23 The experience of overseas jurisdictions suggests a range of options are available for applying LRMC charges on a capacity basis, including:

(a) capacity of transmission customer's connection to the grid

(b) maximum capacity of equipment used to consume transmission services

(c) demand for transmission services in kW during congestion or peaks, depending on which is used.

If LRMC charges were applied, which parties should be subject to LRMC charges?

8.24 The purpose of an LRMC charge would be to signal to consumers of transmission services the long-run cost implications of their demand for transmission services. All consumers of transmission services should therefore be subject to LRMC charges if those charges were introduced. The parties consuming transmission services are generators and loads. Since decisions by both generation and load can affect the requirement for transmission investment in principle both should be subject to LRMC charges.

8.25 This is reflected in the TNUoS charges in the UK, which are applied to both generators and load. The GTUoS charges in Ireland and Northern Ireland only apply to generators.

8.26 As noted in section 7, in both of these jurisdictions the total amount that can be charged to generation and load, including generation and load, is set by a fixed proportion to each (e.g. in the UK 27% to generation and 73% to load). However, in principle there should be no limit on the share of LRMC charges borne by generation or load. This is because the charge should depend on the extent to which a party's demand for transmission services affects transmission investment.

8.27 As with beneficiaries-pay charges, a key question would be which of distributors or retailers should face the LRMC charges relating to demand for transmission services by mass market load. If LRMC charges were applied on the basis of capacity of connection to the grid, rather than on an energy basis, it may be more appropriate to charge distributors rather than retailers. This is because distributors rather than retailers determine the capacity of connections to the grid for mass-market load.

8.28 In the case of generators, LRMC charges should in principle apply to any generator whose demand for transmission services could lead to a requirement for transmission investment. This could be both grid-connected generation and distributed generation. As with beneficiaries-pay charges, a capacity threshold for application of the charges may be required to limit the transactions costs associated with applying the charge.

8.29 In summary, if LRMC charges were applied, it is likely to be appropriate to apply LRMC charges to generators, direct connect consumers and, if applied on a capacity basis, to distributors.

Would charging current grid users for future capital investment be sustainable?

8.30 A potential issue with LRMC charging is whether it would be sustainable for a regulated charging regime to charge current grid users on the basis of planned future capital investments. There are two main technical issues to consider, but there is also a subjective element to the question of whether such a regime would be robust and sustainable over time.

8.31 First, the Code specifies that the TPM relates to the allocation of the recovery of costs *incurred* by Transpower.[62] This means that the TPM cannot be used to "pre-fund" investment costs that have yet to be incurred. However, the Code does not appear to prevent recovery of investment costs incurred by Transpower with a method that allocates those costs based on the costs of future investments, as would be the case with an LRMC charge. This is of course provided the allocation is consistent with the Authority's statutory objective.[63] The Authority considers that an LRMC charge could potentially be an allocation consistent with the Authority's statutory objective.

8.32 Second, LRMC charging involves estimates of LRMC based on current technology but relates to future investment costs. This means there would be a risk that if the investment is actually made:

(a) the technology used for that investment may be different from that on which the LRMC calculation is based

(b) the parties subject to LRMC charges may be different from those that benefit from the investment.

8.33 The main risk with (a) would be that technological change raises a risk of a mismatch between LRMC charges and the actual costs of the investment. Since technological change would probably be more likely to reduce rather than increase costs, LRMC charges may be higher than would be efficient. The consequence of an excessive LRMC charge would be lower demand for transmission services than is efficient and inefficient deferment of investments.

8.34 While this risk is a real one, the key question is whether the efficiency consequences of this are worse than the alternatives. For example, the charges under the status quo and beneficiaries-pay charges are based on the actual costs of investments that have been incurred, ie historical costs. This means that to the extent there is a risk of over-charging with LRMC charges it may actually be worse for the status quo and beneficiaries-pay.

62 In particular, clause 12.77 of the Code provides: "The costs incurred by Transpower (irrespective of when they are incurred) in relation to an approved investment are recoverable by Transpower from designated transmission customers on the basis of the transmission pricing methodology and must be paid by designated transmission customers accordingly." Clause 12.78 provides: "The purpose of the transmission pricing methodology is to ensure that, subject to Part 4 of the Commerce Act 1986, the full economic costs of Transpower's services are allocated in accordance with the Authority's objective in section 15 of the Act."

63 See clause 78 of the Code.

8.35 Second, the risk can be mitigated to some degree by calculating LRMC charges based on the most efficient available technology rather than the technology Transpower may currently use. This is the approach the Commerce Commission uses for setting TSLRIC charges for telecommunications services. It means, for example, that wireless or fibre technologies may be used to set charges even though the regulated provider may use copper to deliver the telecommunications service for which the price is being set.

8.36 The main risk with (b) would be that current users may cross-subsidise the costs of future users. However, since the Code prevents LRMC charges from being used to pre-fund investments this is really only a problem in theory rather than in practice. The costs of future investments would still need to be recovered once they are actually incurred. Further, for many potential investments in the grid it is unlikely that transmission flows will change so as to mean the beneficiaries of investments are substantially different from those incurring LRMC charges.

8.37 More fundamentally, an LRMC charging regime may be unsustainable as parties would be paying charges based on assets/services that don't yet exist. The charges are likely to be viewed by payers as critically dependent on questionable assumptions and forecasts, and ongoing revisions to those assumptions and forecasts would likely make it clear that the setting of the charge is highly subjective. These issues lead the Authority to question whether the charging regime would be sufficiently robust over time to be sustainable.

Would LRMC charges provide perverse price signals?

8.38 As discussed earlier, LRMC charges provide price signals based on investments that are expected to occur in the (distant) future, but the LRMC charges for each investment reduce to zero immediately the new asset is commissioned. Once a party is charged for future investments they would appear to have perverse incentives to lobby for those investments to occur as soon as possible so as to reduce the charge to a minimum. LRMC charges should increase to the extent an investment is brought forward, which would impact on demand and therefore forestall the need for the investment. To the extent this does not occur, LRMC charges may not in practice provide efficient price signals, in which case LRMC charges could encourage inefficient timing of investment.

9 Preliminary assessment of LRMC charging

Introduction

9.1 This section provides a preliminary assessment of LRMC charging against the status quo. As with the beneficiaries-pay options, the Authority would conduct a full assessment of options for LRMC charges if, following submissions on this working paper, the Authority decides to develop specific options for LRMC charges. If the Authority decides to propose an LRMC charge in the second issues paper, a full cost-benefit analysis (CBA) of that option would be provided in that paper, along with a full CBA of other options considered.

Lawfulness of option of LRMC charges

9.2 The option of amending the TPM to provide for LRMC charging would be lawful. As discussed in paragraph 8.31 above, the Code does not appear to prevent recovery of investment costs incurred by Transpower with a method that allocates those costs based on the costs of future investments, as would be the case with an LRMC charge.

Practicability of LRMC charges

9.3 There are a number of practicability issues that would need to be addressed before applying an LRMC charge. On a technical level these include:

(a) the definition of LRMC to be used

(b) the methodology used for calculating LRMC. A key question is where the balance should lie in terms of efficiency of price signal versus volatility of the charge. Charge volatility may cause uncertainty, which may counteract the benefit of an LRMC charge of promoting more efficient investment. While MIC is theoretically efficient it is volatile. By contrast, AIC is much more stable but likely to deviate from the efficient level. LRIC is intermediate between those approaches in terms of its volatility and efficiency. A decision would therefore be required on which method would provide the best balance between the efficiency of its price signal and the level of charge volatility

(c) the appropriate approach for forecasting demand for transmission services to be used for calculating LRMC

(d) the appropriate approach for forecasting the transmission investments required to meet the forecast demand for calculating LRMC. The Authority notes that under the Commerce Commission's Capital Expenditure Input Methodology for Transpower, Transpower is required to provide a forecast for investments over the next 10 years, split between base capex and major capex. This may be an option for transmission investment forecasting for calculating LRMC charges, though may be insufficient if the calculation period was longer than 10 years (see (f) below)

(e) depending on the methodology chosen, the forecasting period used to calculate LRMC charges. Depending on the method this may need to be a long period into the future, e.g. 20 years or more.[64] However, forecasting long into the future is problematic given the increasing uncertainty the further in the future the forecasting period

(f) whether LRMC charges would be made at a nodal or zonal level

(g) how LRMC charges at a node or zone would be calculated

(h) whether adjustments should be made for the signals provided by nodal pricing

(i) determining the parties to be subject to LRMC charges. As with other transmission charges, the extent to which charges are applied to load versus generation is likely to be controversial. The Authority understands that there has been considerable debate in the UK over changing the proportion of TNUoS charges paid by load and generation, which raises questions about the sustainability of the regime. This is also a matter that would be controversial should LRMC charges be applied in New Zealand

(j) the basis for applying LRMC charges, including whether this should be on:

   (i) peaks or congestion and what would constitute a peak or congestion for charging

   (ii) on a capacity or energy basis and how this would be set.

9.4 In addition to those technical issues, there are regulatory issues about whether the LRMC approach in practice provides perverse price signals and whether it would be sustainable over time. In particular:

(a) LRMC charges provide price signals based on investments expected to occur in the (distant) future. The LRMC charges for each investment reduce to zero when the new asset is commissioned. Once a party is charged for future investments they would appear to have perverse incentives to push for those investments to occur as soon as possible so as to reduce their charges to a minimum. To the extent that adjustments to timing of investments are not reflected in LRMC charges, LRMC charges would encourage inefficient timing of investment. Having a charging basis such as beneficiaries pay applying following commissioning of investments would counteract this effect.

(b) whether the regulator can reasonably assess the accuracy of the forecasts of demand and transmission investments

(c) as these forecasts are likely to change over time, and new investment and technology options will arise over time, whether the charging regime would

64 Some methods may involve much shorter periods. As noted in section 7, the forecasting period for the Irish GTUoS charge is only 5 years, so the uncertainty for this charge is not large.

be sufficiently robust to be sustainable. In addition, there is the question of how the LRMC charge would evolve in situations where new information causes large revisions to these forecasts. Examples of this include the global financial crisis, which has led to large changes in demand. Another example is a large earthquake in a region that destroyed part of the transmission grid serving a city. There is also the question of the timing of reduction of LRMC charges to zero following an investment – in particular, whether this should be when the decision was made to proceed with the investment or when work on the investment had begun.

9.5 Most of these practicability issues are discussed in this paper. The Authority notes that the practicability issues are considerable and are therefore likely to require significant time to resolve. Further, the regulatory issues raise questions about whether LRMC charges would be sufficiently robust to be sustainable. The Authority would welcome submitters' views on whether these issues can be readily addressed.

9.6 As noted in section 5, if LRMC charges were applied but did not fully recover Transpower's costs the Authority's decision-making and economic framework implies a beneficiaries-pay charge should be applied to recover remaining costs. Since transmission investments are long-lived assets there may be long periods in which LRMC charges may recover only a small proportion of costs, implying much of the costs would be recovered through other charges. The combination of LRMC and beneficiaries-pay charges, and possibly residual charges, would create very significant complexity.

9.7 The combination of LRMC and beneficiaries-pay charges would also require considering the price signals implied by the two charges and, if necessary, altering the design of the charges to ensure the price signals provided were efficient. If a residual charge were also required, it would probably need to be designed to be non-distortionary, if LRMC and/or beneficiaries-pay charges provide all the price signals required.

Costs and benefits of LRMC charging

9.8 Relative to the status quo, the benefits of LRMC charging are:

(a) LRMC charges could promote more efficient investment if parties consuming transmission services face charges related to the investment cost implications of their consumption of transmission services. As noted earlier, LRMC charges could create perverse price signals and promote inefficient investment.

(b) LRMC charging could promote a more durable TPM by charging all parties consuming transmission services using both HVDC and interconnection assets on the same basis. To the extent that LRMC charging promoted a more durable TPM, it would reduce uncertainty, and therefore promote more efficient investment. As noted earlier, though, the Authority questions whether LRMC charges would be robust and sustainable.

(c) LRMC charges could promote efficient use of the grid as the charge would only result in parties avoiding use of the grid to the extent that the benefit they obtained from use of the grid during congestion or peaks was less than the investment cost implications of their consumption. By contrast, under the status quo, the charge a party incurs for consumption during peaks bears little relationship to the cost implications of their consumption of transmission services. Like the situation under the status quo, provided LRMC charges were applied only to peaks or congestion, use of the grid outside peaks or congestion would be unaffected by LRMC charges.

(d) LRMC charges could promote more efficient allocation of the costs of the grid as parties would incur LRMC charges only to the extent that their consumption of transmission services had future investment cost implications. Further the charges a party incurred would relate to the specific cost implications of their consumption and not the cost implications of consumption of transmission services by other parties, as is the case under the status quo.

9.9 Relative to the status quo, the costs of LRMC charging are:

(a) Implementation costs for both Transpower and participants, including set-up costs involved in implementing the option, including computer equipment, development and testing. Relative to the status quo, the implementation costs of LRMC charging are likely to be large.

(b) Operational costs to Transpower and the party calculating and applying LRMC charges (if this was not Transpower). The Authority notes that some of the costs involved in calculating LRMC charges may already be incurred by Transpower in their forecasting of future transmission investments.

(c) Costs to participants to verify their LRMC charges.

(d) Allocative and productive inefficiency to the extent that applying LRMC charges to generators affects efficient dispatch of generators during peaks or congestion. However, those costs should not be large since LRMC charges should be cost-related so arguably generators should consider the transmission investment cost implications in their operation to the extent those costs are not provided through nodal pricing.

(e) Dynamic, allocative and productive inefficiency to the extent that LRMC charges over-signal the cost implications of consumption of transmission services where those signals are already provided by nodal pricing. Those costs could be mitigated to some extent by adjusting LRMC charges to take account of the signals provided by nodal pricing.

(f) Dynamic inefficiency to the extent that LRMC charging is not durable because of perceptions that it charges current users of the grid for future transmission investments. In addition, LRMC charges may provide incentives to advocate for inefficiently advancing investments as once commissioned a party's LRMC charges would reduce to a minimum (although bringing forward the investment would imply higher LRMC charges prior to commissioning). To the extent this is an issue it could introduce uncertainty about the durability of the TPM, which would undermine investment.

9.10 A CBA would be required to determine whether LRMC charges would provide net benefits relative to the status quo. The Authority's preliminary assessment is that LRMC charges could provide net benefits relative to the status quo. A final assessment would depend on whether the potential efficiency improvements resulting from LRMC charges would occur in practice under a regulated regime, and if so, whether they would outweigh the significant implementation, operational and other costs of applying those charges.

10 Conclusion

10.1 The preliminary assessment in the previous section suggests that there may be net benefits from applying LRMC charges. However, LRMC charges are likely to be significantly more complex than the status quo, and the effort to develop and apply LRMC charges is likely to be considerable. Moreover, the Authority questions whether the LRMC approach provides perverse price signals and whether it would be sustainable over time. These considerations raise the question of whether LRMC charges would be practicable. The Authority would therefore welcome submitters' views on whether LRMC charges are likely to better promote the Authority's statutory objective than the status quo or beneficiaries-pay, and should therefore be investigated further.

10.2 If, following submissions on this working paper, the Authority decides to further investigate LRMC charges, the Authority would develop and model LRMC charge options. Those options would be considered in a subsequent working paper. If the Authority decides to propose to amend the TPM to include LRMC charges, a specific proposal would be provided in the second issues paper together with a detailed cost-benefit analysis of the proposal relative to the status quo.

Appendix A Illustration of AIC, LRIC and MIC calculations using a simplified transmission grid

Introduction

A.1 The Authority modelled a simplified transmission grid (grid) over 24 years to compare AIC, LRIC, and MIC-based LRMC charges and the revenue that they might collect if the charge was allocated equally to load and generation during peaks. This modelling is for illustrative purposes to give submitters a high-level understanding of the charging implications of the different LRMC calculation methodologies. It does not indicate how the Authority would apply an LRMC charge if the Authority decided to do this.

Modelling approach and key assumptions

A.2 The modelled grid is described in Table 1 below. Namely the grid has an opening regulatory asset base (RAB) of $4 billion, with capex of $0.5 billion in years 12, 18, and 24, resulting in a RAB of $5.5 billion from year 24 to year 30. The grid spans over two islands, a North Island (NI) and a South Island (SI), with an HVDC cable connecting the two islands. Peak demand in year 1 is assumed to be 6,000 MW, increasing to 8760 MW at the end of 24 years.

A.3 Further assumptions of the grid are detailed below:

(a) There is an assumption of perfect foresight about the timing and magnitude of capex requirements and about changes in peak demand over the thirty year period analysed.

(b) Incremental operating expenses are not included in the calculations. While incremental operating expenses are normally a component of LRMC calculations, they are left out as they generally make a relatively minor contribution to LRMC.

(c) There are no electricity losses (i.e. generation equals demand).

(d) All transmission lines are assumed to have equal impedance.

(e) Grid valuations assume no depreciation or revaluations.

(f) The grid is assumed to have 5 nodes only, consisting of two generators and three loads.

(g) LRMC charges are based on an equal allocation to peak generation and peak load.

(h) Incremental demand is used as a proxy for peak demand.

A.4 The location of grid augmentation forecasts for years 12, 18 and 24, is illustrated in Figure 1 below. Namely capital expenditure is forecast to augment lines between nodes B and C in year 12, the HVDC cable in year 18, and the lines between nodes A and B in year 24. Demand is assumed to increase at nodes A, B, and D by 1.1% p.a. for years 1 to 11, by 2.8% p.a. for years 12 to 18, and by 1.5% p.a. for years 19 to 24.

Figure 1: Grid augmentations for a six node hypothetical grid

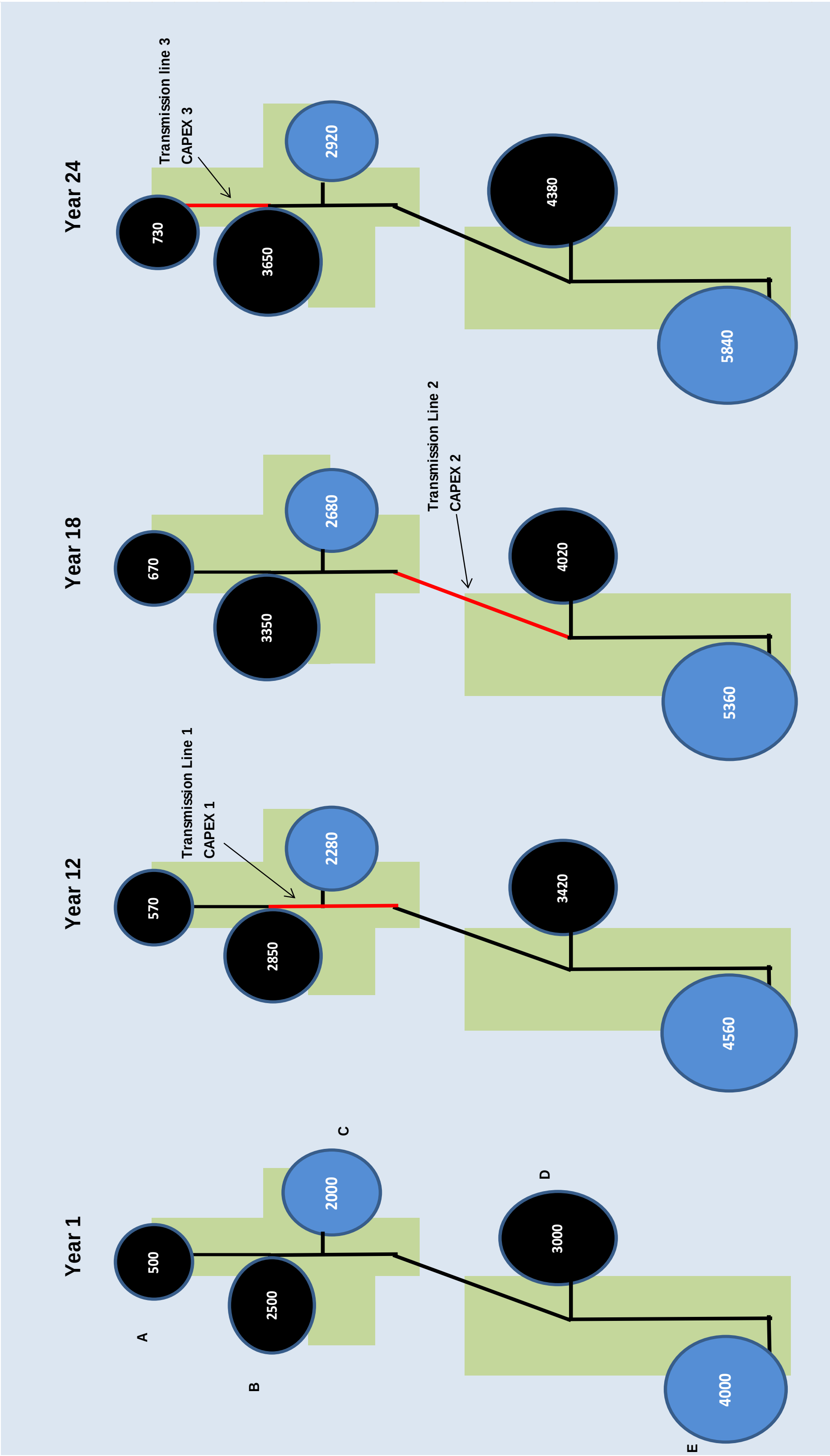


Table 1: details of the hypothetical grid

Year	Forecast capex ($m)	RAB ($m)	Demand node A (MW)	Demand node B (MW)	Generation Node C (MW)	Demand node D (MW)	Generation node E (MW)	Total demand (MW)	Total generation (MW)
1		4,000	500	2,500	2,000	3,000	4,000	6,000	6,000
2		4,000	506	2,529	2,023	3,035	4,047	6,070	6,070
3		4,000	512	2,558	2,047	3,070	4,093	6,140	6,140
4		4,000	517	2,587	2,070	3,105	4,140	6,210	6,210
5		4,000	523	2,616	2,093	3,140	4,187	6,280	6,280
6		4,000	529	2,645	2,117	3,175	4,233	6,350	6,350
7		4,000	535	2,675	2,140	3,210	4,280	6,420	6,420
8		4,000	541	2,704	2,163	3,245	4,327	6,489	6,490
9		4,000	547	2,733	2,187	3,280	4,373	6,559	6,560
10		4,000	552	2,762	2,210	3,315	4,420	6,629	6,630
11		4,000	558	2,791	2,233	3,350	4,467	6,699	6,700
12	500	4,500	570	2,850	2,280	3,420	4,560	6,840	6,840
13		4,500	587	2,933	2,347	3,520	4,693	7,040	7,040
14		4,500	603	3,016	2,413	3,620	4,827	7,240	7,240
15		4,500	620	3,100	2,480	3,720	4,960	7,440	7,440
16		4,500	637	3,183	2,547	3,820	5,093	7,639	7,640
17		4,500	653	3,266	2,613	3,920	5,227	7,839	7,840
18	500	5,000	670	3,350	2,680	4,020	5,360	8,040	8,040
19		5,000	680	3,400	2,720	4,080	5,440	8,160	8,160
20		5,000	690	3,450	2,760	4,140	5,520	8,280	8,280
21		5,000	700	3,500	2,800	4,200	5,600	8,400	8,400
22		5,000	710	3,549	2,840	4,260	5,680	8,519	8,520
23		5,000	720	3,599	2,880	4,320	5,760	8,639	8,640
24	500	5,500	730	3,650	2,920	4,380	5,840	8,760	8,760

A.5 In order to calculate LRMC by node, it was necessary to allocate a portion of forecast capex to each of the five nodes. This is necessary because in order for LRMC to contain an efficient investment signal, LRMC needs to vary by location. More specifically, LRMC prices, which are forward looking, should be higher at nodes where changes to parties' injection or offtake behaviour would contribute toward forecast grid augmentations. Note that if LRMC charges were applied, a methodology would need to be developed to identify the extent to which injection or offtake at a node contributed to future investment costs.

A.6 The process undertaken to allocate forecast capex to nodes is based on electricity flow analysis, taking into account the path of least resistance, where (assuming equal impedance of all transmission lines) nodes A to E are assumed to be situated along a bus, and flows are prorated based on each node's contribution to the bus. For example, in year 1, node E in the SI injected 4000 MW into the grid and the demand at node D (also in the SI) was 3000 MW. While it might appear efficient for node E to supply 3000 MW to node D, due to assuming equal impedance of the lines connecting E, D and C, 2000MW would flow from node E to node D with the balance of 2000MW flowing to the NI. Correspondingly, since there is equal impedance in the lines running from C to B and C to D, 1000MW of generation injected at node C would flow north with the other 1000MW flowing to the SI and supplying node D. By calculating flows between each node, a portion of forecast capital expenditure was allocated to each node in order to calculate LRMC separately at each node.

A.7 Table 2 below illustrates the calculation by which the costs of grid augmentations are allocated to nodes. In the case of transmission line 1 in year 12, generation at node E increased from 4,000MW to 4,560MW between years 1 and 12, but (because of Kirchhoff's law) half of this volume travelled to the NI to supply nodes A and B. The incremental generation of node E supplying nodes A and B via transmission line 1 is 280MW (2,280MW - 2,000MW). This determines node E's contribution to the need to expand the capacity of transmission line 1, and therefore its allocation of capex 1 at 24% or $121.21 million.

A.8 Similarly, for augmentation of transmission line 3 in year 24, the only parties which contributed to the need to augment transmission line 3 were node A which received 730MW (and an incremental volume of 60MW), and the generators at nodes C and E which both supplied 30 MW each of the incremental volume. Accordingly, node A is allocated 50% of the forecast costs of capex 3 and nodes C and E are each allocated 25% of the costs of capex 3.

Table 2: Allocation of augmentation costs to nodes[65]

Node	Demand (MW)	Previous demand (MW)	Incremental demand (MW)	Use of the grid being augmented (MW)	% of portion of capex cost	Allocated Portion of CAPEX ($m)
Capex 1						
A	570	500	70	35	3%	15.15
B	2,850	2500	350	350	30%	151.52
C	2,280	2000	280	280	24%	121.21
D	3,420	3000	420	210	18%	90.91
E	4,560	4000	560	280	24%	121.21
Total	13,680	12,000	1,680	1,155	100%	500.00
Capex 2						
A	670	570	100	50	4%	20.83
B	3,350	2,850	500	250	21%	104.17
C	2,680	2,280	400	200	17%	83.33
D	4,020	3,420	600	300	25%	125.00
E	5,360	4,560	800	400	33%	166.67
Total	16,080	13,680	2,400	1,200	100%	500.00
Capex 3						
A	730	670	60	60	50%	250.00
B	3,650	3,350	300	-	0%	-
C	2,920	2,680	240	30	25%	125.00
D	4,380	4,020	360		0%	-
E	5,840	5,360	480	30	25%	125.00
Total	17,520	16,080	1,440.00	120	100%	500.00

A.9 The LRMC price for all three LRMC methods (AIC, LRIC and MIC) is a factor of forecast capex and incremental demand components for a single period, whether it is 10 years (as in the modelled AIC method), or a single increment in demand as compared to current demand (as in the modelled MIC method). The price calculated will always be a factor of those two key components.

65 In relation to capex 2, it could be argued that the existence of the node C generator reduces the capex 2 HVDC augmentation requirement, as it enables NI load to be served by NI generation. However, as discussed above, the model assumes power sharing whereby flows are calculated by pro-rating each node's contribution to the bus (and assuming equal impedance of all transmission lines in the model). In the model, node C would contribute to capex 2 because the model assumes that half of node C's flows travel south and half of node E generation flows to the NI. Thus, in the model, node C contributes to the cost of the HVDC augmentation.

A.10 Where LRMC is calculated across multiple nodes, LRMC will simply be the (present value of) capex allocated to that node divided by the (present value of) incremental demand at that node, over a defined time period.

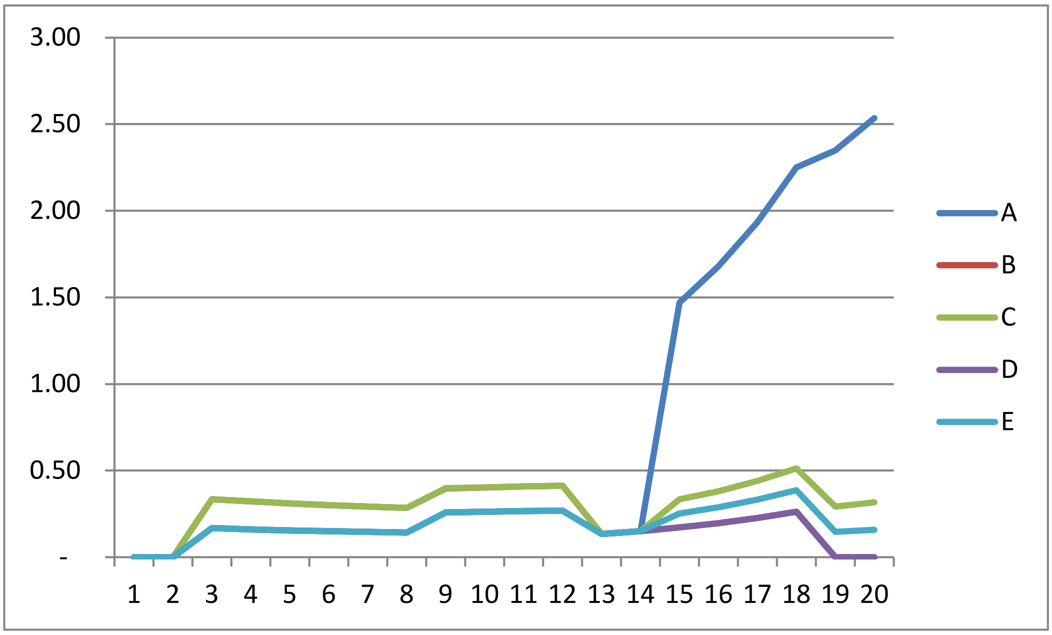
AIC calculation

A.11 The AIC calculation is based on a 10-year projection. At a high level, the calculation is the sum of present value of projected capex (discounted to present value) for the following 10 years divided by projected incremental demand over the following 10 years (discounted to present value). The AIC calculation is repeated every year for the next 20 years. 30 years of data rather than 20 years are required to perform this calculation. i.e. at year-20 the AIC calculation is forward looking by 10 years and therefore it requires data from years 20 to 30.

A.12 Figure 2 below illustrates LRMC in $m/MW over the 20 year analysis. Note that the LRMC cost increases when a forecasted grid augmentation is less than 10 years away (in which case the cost is included in the LRMC calculation). Correspondingly, LRMC reduces once an augmentation is completed (and the capex no longer falls within the next 10 years and accordingly falls out of the LRMC calculation).

A.13 Note there is a significant increase in the AIC for node A, from year 14. This is due to capex 3 falling within the 10 year forecast in year 14 (and thus entering the AIC equation). Node A has a particularly large allocation of capex 3 since it is one of the only users of that part of the grid. Its LRMC is also high given that there is a relatively low volume of incremental demand with the ten year forecast from which to spread the charge.

Figure 2 – AIC – LRMC prices in $000,000/MW over a 20 year period

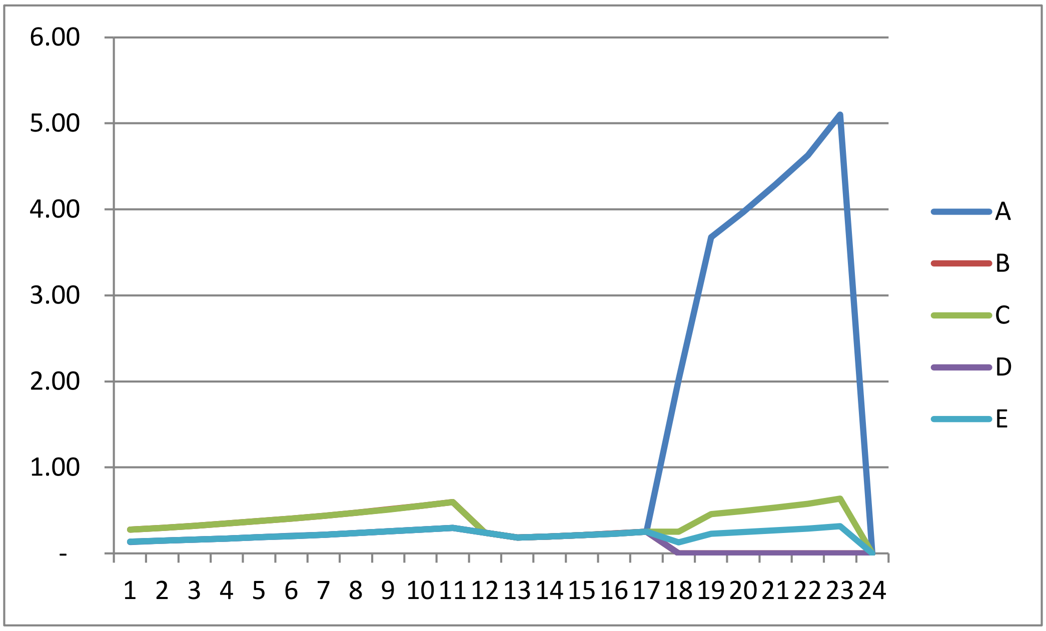


LRIC calculation

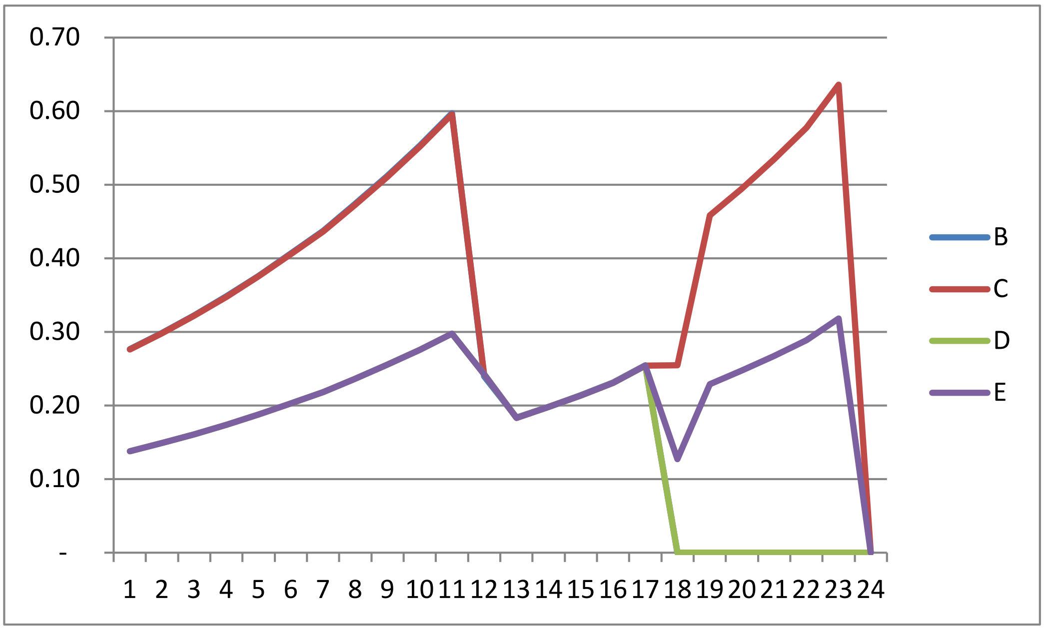
A.14 The LRIC calculation is similar to the AIC calculation except that, rather using a 10 year forward looking timeframe, the LRIC utilises the timeframe until the next capital expenditure forecast (by node). For example, for the LRMC calculations in year 1 through to year 11, the next capex investment is the year 12 capex of $0.5 billion. The year 12 grid augmentation will affect LRMC for all nodes as every node's injection or offtake behaviour will impact the capacity at transmission line 1. As illustrated in figure 3 below, under LRIC, the LRMC price (in $/MW) increases as that year 12 investment approaches. Once that investment is complete, the timeframe till the next investment is selected and the LRMC price drops to reflect that the investment has taken place. Note that a graph is included in Figure 3 that takes out the LRIC for Node E. This is provided so that the pattern of LRIC price changes is more observable. Namely, prices will generally increase until the next investment is completed. The prices drop to zero in year 24 as there is no future capex forecasted after year 24.

Figure 3 – LRIC – LRMC prices in $000,000/MW over a 24 year period

With Node A included



Without Node A



Marginal Incremental Cost (MIC)

A.15 The MIC calculation assesses the impact on capital expenditure requirements when demand is increased by an increment, which in this case is one year of incremental demand. The impact that the increment in demand had on the timing of the investment is observed and the MIC is the present value of the difference between the present value of the increment demand scenario and the present value of the forecast demand, divided by the increment in demand.

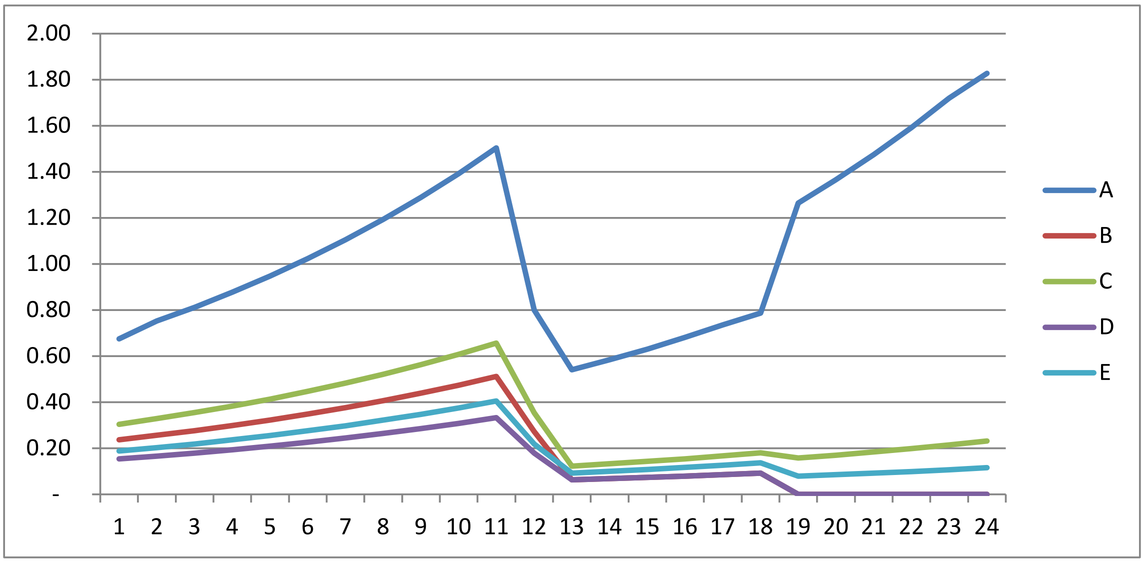
A.16 In the model, the impact of the demand increment is that the investment is triggered one year early.

A.17 Figure 4 below shows the change in prices over time by node. Note that a further graph is provided which does not include node A which is seen as something of an anomaly (given its share of capex and its somewhat modest incremental demand from which to spread the cost).

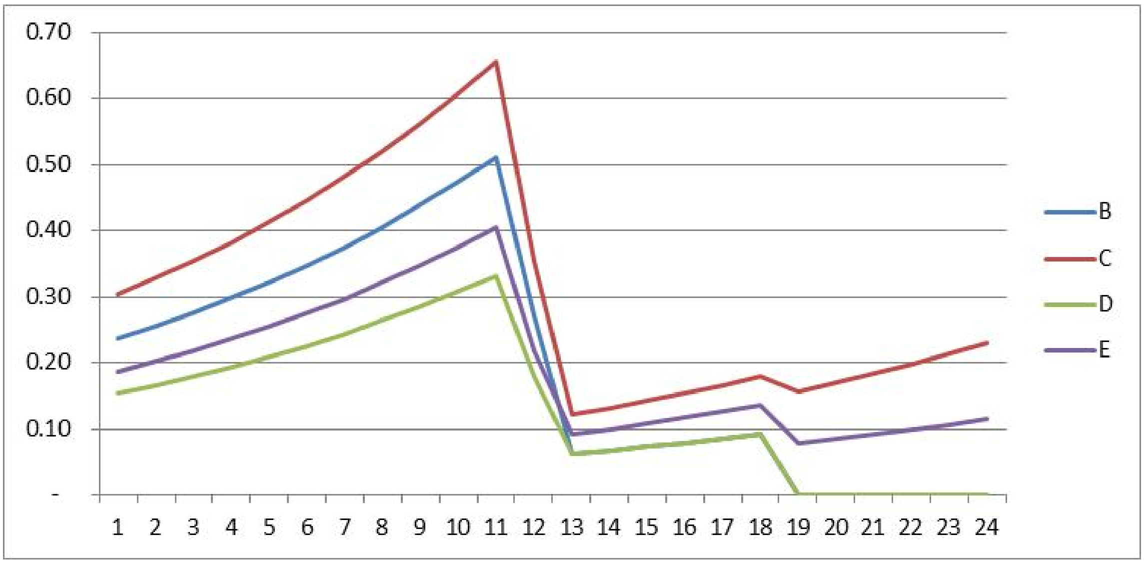
A.18 In general, with MIC, prices increase as an investment draws closer. This is because, since capex is discounted to a present value in the formula, as the investment draws closer, discounting reduces.

Figure 4 – MIC – LRMC prices in $000,000/MW over a 24 year period

<u>With Node A included</u>



<u>Without Node A</u>

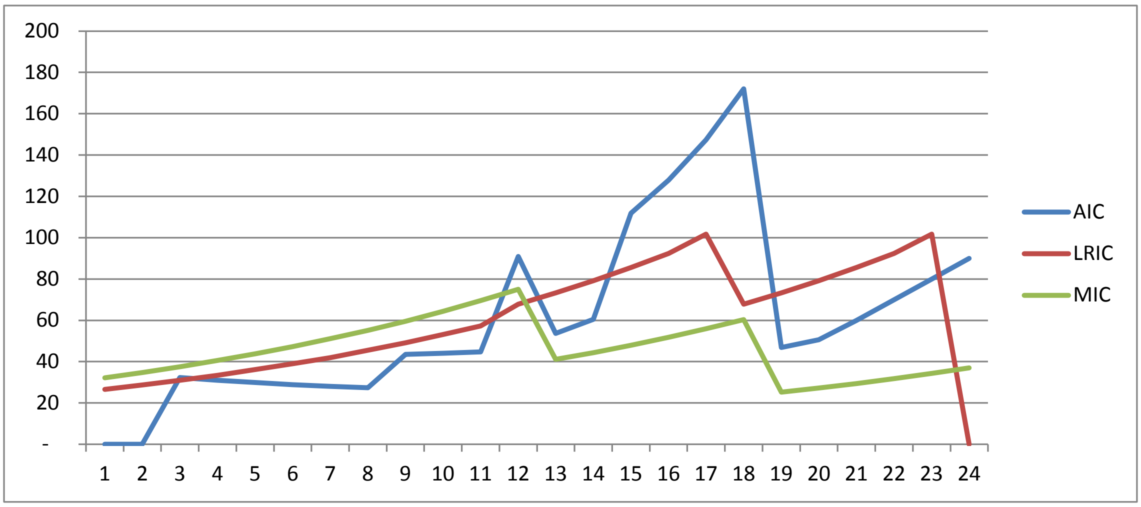


Revenue generated under each LRMC method when charging LRMC to peaks

A.19 Figure 5 below illustrates average revenue over 24 years if LRMC is applied only to peak demand (assumed to be incremental demand). Total cost recovery for AIC, LRIC, and MIC is $1.47 billion, $1.44 billion, and $1.10 billion, respectively over the 24 year period. Revenue under each scenario falls well below MAR (which is around $1 billion annually[66]) for all methods. This is because, when the LRMC is applied to incremental demand, it will not recover more than future capital expenditure forecasts. Note that if LRMC is applied to all demand, revenue will be considerably higher. Note also that recovery is only slightly under the capex forecast of $ 1.50 billion during the 24 year period. This suggests that if LRMC is applied to incremental demand, future capex requirements would largely be recovered under either method.

A.20 However, as illustrated below, charges can vary considerably from year to year under all methods.

Figure 5 – LRMC revenue if LRMC is applied only to peaks (in $000,000)



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66 This was calculated by applying approximately the same ratio of MAR to RAB that was applied to Transpower in 2013.

Glossary of abbreviations and terms

Act	Electricity Industry Act 2010
ACOT	Avoided cost of transmission
AEMC	Australian Electricity Market Commission
AIC	Average incremental cost
APR	[Transpower's] Annual Planning Report
Authority	Electricity Authority
capex	Capital expenditure
CBA	Cost-benefit analysis
Code	Electricity Industry Participation Code 2010
GIT	Grid investment test
GTUoS	Generator transmission use of system charges – transmission charges applied in Ireland and Northern Ireland
GWh	Gigawatt hour
HVDC	High voltage direct current
IPP	Individual price-quality path
km	Kilometres
kWh	Kilowatt hour
LCE	Loss and constraint excess
LRIC	Long-run incremental cost
LRMC	Long-run marginal cost
MAR	Maximum allowable revenue
MIC	Marginal incremental cost
MW	Megawatt
MWh	Megawatt hour
NI	North Island
opex	Operating expenditure
RCPD	Regional coincident peak demand
SI	South Island
SPD	Scheduling, pricing and dispatch [model]
SRMC	Short-run marginal cost
TELRIC	Total element long-run incremental cost
TNUoS	Transmission network use of system charges – transmission charges applied in the United Kingdom except Northern Ireland

TPAG	Transmission Pricing Advisory Group
TSLRIC	Total service long-run incremental cost