Identification of high-level options and filtering criteria

A REPORT PREPARED FOR THE NEW ZEALAND ELECTRICITY COMMISSION

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Executive summary

Introduction

This report has been prepared by Frontier Economics (Frontier) for the New Zealand Electricity Commission (the Commission) as a contribution to the first Stage of the Commission's *Transmission Pricing Review: High Level Options Investigation* (the Review). Stage 1 of the Review is concerned with the establishment of high-level options for transmission pricing. This is to be followed by Stage 2, involving more detailed analysis to form a short list of options and Stage 3, which involves identification and evaluation of a preferred option.

Framework for deriving high-level options

Our framework for deriving high-level transmission pricing options is based on the previous reports prepared for the Commission on efficient pricing theory, international experience and current issues in the New Zealand market, as well as the range of relevant policy and regulatory considerations set out in the Electricity Act, Part F of the Electricity Governance Rules and the Government Policy Statement.

In virtually all circumstances, it will not be possible to give equal weight to all of the pricing principles due to conflicts between them. For example, developing a transmission pricing methodology that provides strong locational signals may require a departure from recovering sunk costs in a least-distortionary manner. In such cases, it will be necessary to make trade-offs between the principles and the high-level options identified in this report involve attempts to make such trade-offs.

High-level options

In addition to the status quo transmission pricing arrangements, we have identified three other high-level options that are worthy of further investigation and consultation. These three other options are:

- 'Tilted' postage stamp approaches
- Augmented nodal price signals
- Load flow-based approaches

Further to these high-level options, there are three other key issues arising in the consideration of transmission pricing methodology. These are:

- Approach to setting connection charges, which could involve a 'deep connection' (or 'but for') charging approach, as employed in several jurisdictions in the United States

- Treatment of transmission alternatives
- Linking transmission pricing with service quality.

The current transmission pricing regime reflects a view that there is little need for transmission pricing to provide additional locational signals for participant investment decisions on top of nodal pricing in the energy market and charging participants for the spur line connection assets. All the other approaches are predicated on these existing signals being insufficient to promote efficient participant investment decisions.

The tilted postage stamp approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.

The augmented nodal price signals option seeks to directly address the deficiencies in nodal energy prices created by excessive or premature network investment. Under this regime:

- Transmission charges should be highest for those generators and loads that <u>benefit most</u> from excessive or premature network investment
- Transmission charges should be lowest for those generators and loads that are made <u>most worse off</u> from excessive or premature network investment

Load flow-based transmission pricing options involve a process of attributing network costs to participant connection points based on an engineering estimation of the network assets 'used' to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (cost reflective network pricing or CRNP) or on forward-looking network development costs, as in Great Britain (investment cost related pricing or ICRP). The CRNP approach can produce perverse pricing outcomes that strongly diverge from long run marginal cost (LRMC), although this can be mitigated by modifying the methodology to take account of patterns of network utilisation. Load flow modelling lacks transparency but is replicable. It is feasible that this approach could achieve similar results to the tilted postage stamp approach from a sounder analytic base and without having to rely on the somewhat arbitrary assumptions required for the tilted postage stamp approach.

One option for changing connection charging is the adoption of a 'deep' connection approach as in the PJM market in the United States. However, this would need to be reconciled with a number of other features of the New Zealand market arrangements and several implementation issues would need to be resolved.

Transmission alternatives should generally face similar transmission pricing signals as grid-connected loads and generators. However, it may be worth clarifying the treatment of distributed or local generation.

In the past the Electricity Commission has considered various options for strengthening the link between transmission service quality and compensation or liability arrangements applying between Transpower and participants. In this context, there are a number of options currently under consideration.

Filtering criteria

We have developed a number of criteria that could be used for narrowing down the high-level options outlined above for more detailed cost-benefit analysis at a later Stage of the Review. Our proposed criteria are as follows.

Criteria 1: As discussed above, a key driver of the need for locational transmission pricing signals is the extent to which actual transmission network investment exceeds the perfectly efficient level of investment. Therefore, one important filtering criterion is the observed degree of such network 'overbuilding' (if any). We note that the distortions caused by overbuilding will be exacerbated if, as under the current market design, nodal prices are not set to signal the value of unserved energy to consumers when load is shed.

Criteria 2: Another important criterion is the theoretical precision of the methodology, in terms of accurately compensating for the muting of nodal price signals caused by market design or inefficiently excessive or premature network investment.

Criteria 3: The development of locational hedging instruments will also influence the choice of a transmission pricing regime. Broadly speaking, to the extent that locational hedging instruments serve to offset or further mute nodal price signals, the transmission pricing regime will need to impose more locationally-differentiated charges.

Criteria 4: Network topology is another relevant factor in choosing a transmission pricing methodology. In general, load flow approaches are better suited to meshed networks while simpler approaches could be used for radial networks. However, modifications to CRNP can help increase its suitability for radial networks.

Criteria 5: Implementation difficulty and information requirements are another relevant consideration in implementing a transmission pricing methodology.

Criteria 6: The incentives that a transmission pricing regime provides for particular groups of participants to properly scrutinise network planning decisions should also be taken into account.

Criteria 7: Good regulatory practice is an umbrella criterion that encompasses minimising subjectivity, enabling replicability and promoting transparency and predictability of network tariffs. These features all contribute to the degree of confidence that participants can have in the integrity of the signals that the transmission pricing methodology provides.

Criteria 8: Finally, stakeholder acceptability of a pricing regime is relevant, as approaches that are unacceptable to a large proportion of participants will tend to be unstable and face pressures for revision over time.

Different options have different strengths and weaknesses across these filtering criteria.

1 Introduction

1.1 Background

This report has been prepared by Frontier Economics (Frontier) for the New Zealand Electricity Commission (the Commission) as a contribution to Stage 1 of the Commission's *Transmission Pricing Review* (the Review). Stage 1 of the Review is concerned with the establishment of high-level options for transmission pricing. This is to be followed by Stage 2, involving more detailed analysis to form a short list of options and Stage 3, which involves identification and evaluation of a preferred option.

The purpose of this report is to:

- Identify and evaluate high-level options for transmission pricing in New Zealand, drawing on previous work prepared for the Commission as part of the Review.
- Identify a proposed set of criteria and approach for filtering the high-level options and formulating a short list of options in Stage 2 of the Review.

1.2 Structure of the report

This remainder of this report is structured as follows:

- Section 2 explains our framework for deriving high-level options for transmission pricing in New Zealand.
- Section 3 describes and briefly evaluates those high-level options.
- Section 4 discusses potential criteria that could be used to filter the high-level options identified in section 3 and explains how they could be used in stage 2 of the project.

2 Framework for deriving high-level options

Key concepts

Our framework for deriving high-level transmission pricing options is based on the previous reports prepared for the Commission on efficient pricing theory, international experience and current issues in the New Zealand market, as well as the range of relevant policy and regulatory considerations set out in the Electricity Act, Part F of the Electricity Governance Rules and the Government Policy Statement.

In virtually all circumstances, it will not be possible to give equal weight to all of the pricing principles due to conflicts between them. For example, developing a transmission pricing methodology that provides strong locational signals may require a departure from recovering sunk costs in a least-distortionary manner. In such cases, it will be necessary to make trade-offs between the principles and the high-level options identified in this report involve attempts to make such trade-offs.

2.1 Previous work

As part of the process leading to the identification of high-level transmission pricing options, Frontier prepared two reports for the Commission, dealing with:

- efficient transmission pricing theory[1]
- international review of transmission pricing[2]

In addition, the Commission provided Frontier with a draft discussion paper prepared by Strata Energy Consulting (Strata) concerning transmission pricing issues identified by the Transmission Pricing Technical Group (TPTG).[3] The Commission also provided Frontier with a report prepared by Strata on transmission pricing methodologies in New Zealand between 1988 and 2008.[4]

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1 Frontier Economics, *Theory of efficient pricing of electricity transmission services*, July 2009, available here.

2 Frontier Economics, *International transmission pricing review*, July 2009, available here.

3 Strata Energy Consulting, *A discussion paper concerning Transmission pricing issues identified by the TPTG, Draft for TPTG review*, August 2009.

4 Strata Energy Consulting, *DRAFT Report on Transmission Pricing Methodologies – 1988 to 2008*, June 2008.

These reports have assisted in the development of this report in three key ways.

- First, they assisted in coming to the observations made in section 2.3 of this report regarding the relevant policy and regulatory considerations for transmission pricing in New Zealand.
- Second, the previous reports have assisted in developing the four high-level options outlined in sections 3.1 to 3.3 of this report, as well as the discussion of related pricing issues in sections 3.5 to 3.7.
- Finally, the previous reports have also formed the foundation of the proposed filtering criteria discussed in section 4.

2.1.1 Findings of efficient pricing theory report

Frontier's efficient pricing theory report was produced to provide the Commission with a sound theoretical basis for considering and comparing alternative transmission pricing options as part of its high-level options investigation.

The report noted that an energy market with 'full' nodal pricing (incorporating full pricing of congestion and losses and no price caps below the value of unserved energy) ought to provide efficient signals for the use of the existing transmission network. That is, a market with full nodal pricing should provide appropriate signals for participants' operational decisions. The report further noted that if the transmission system is augmented perfectly efficiently, full nodal pricing should also provide appropriate signals for investment by generators and loads. That is, where transmission augmentation is perfectly efficient, nodal pricing should provide investors with incentives to choose the optimum technology, location and timing of new generation plant and load facility.

However, the report also pointed out that economies of scale in transmission ('lumpiness') could mean that – while sending efficient signals within the constraints of the available technologies – nodal price differentials diverge from the averaged long run marginal cost (LRMC) of transmission augmentation for substantial periods of time. This may include long periods of unserved demand, which may be considered unacceptable from a policy perspective.

Furthermore, if the transmission system is augmented inefficiently, nodal prices will not provide appropriate investment signals.[5] For example, if the transmission system is overbuilt due to the risk aversion of network planners or the

5 It also follows from the above discussion that nodal prices will not provide efficient signals if market interventions stop prices from rising to the value of unserved energy if load is shed, as occurs in New Zealand. While it may be possible to design the transmission pricing methodology to compensate for the impact of this type of intervention, the most straightforward solution would appear to be setting nodal prices at the value of unserved energy in the event that load is shed.

application of non-economically-based deterministic reliability standards, nodal price differentials will likewise be inefficiently attenuated. This will tend to 'undersignal' the importance of participants locating in areas where they are least likely to bring forward further augmentation of the transmission grid. Under these conditions, some mechanism or pricing regime will be needed to augment or supplement nodal prices in order to promote efficient load and generation investment decisions.

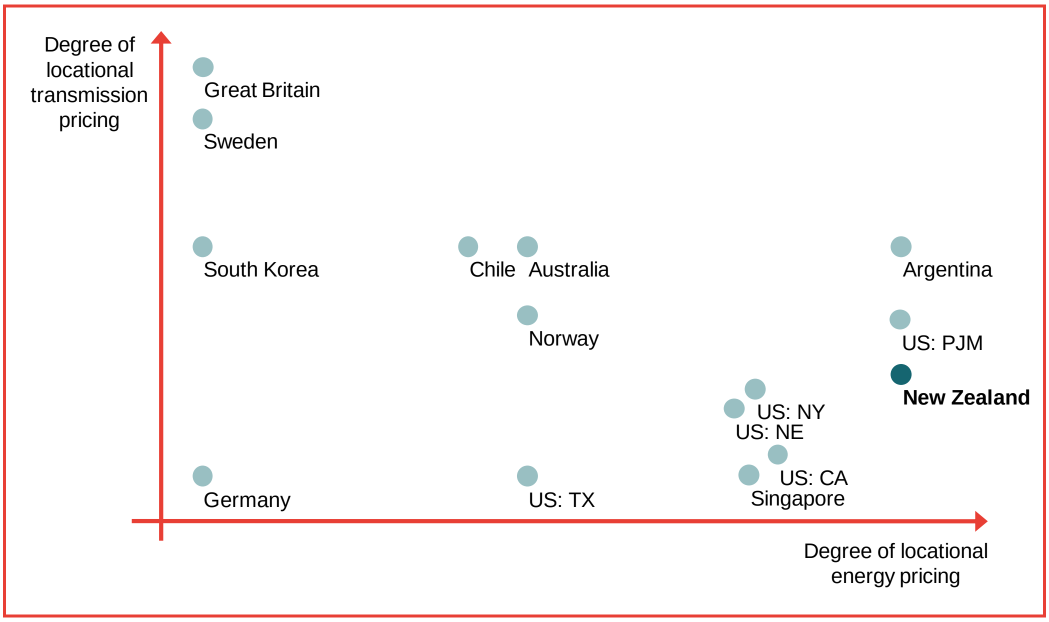
2.1.2 Findings of international review report

Frontier's international review report was prepared to provide the Commission with a broad understanding of the different transmission pricing regimes operating in other modern electricity markets. In total, 15 jurisdictions were reviewed, including the Australian NEM, Great Britain, several United States markets and some progressive European, South American and Asian markets. In order to be undertaken in a timely manner, the review was primarily based on information available online. As a result, it was not always clear how the specifics of each regime operated, nor whether the information presented in the report was current. However, the information was explicitly referenced to facilitate independent analysis should that be deemed necessary and useful.

The international review considered not only the prevailing transmission pricing regime, but also the energy market pricing arrangements. Perhaps unsurprisingly, it found that there tended to be a trade-off between the degree of locational granularity of energy market pricing and the degree of locational transmission pricing. For example, the BETTA market of Great Britain has a single set of energy imbalance prices but a highly refined set of transmission prices based on the ICRP methodology. At the other extreme, New Zealand and Singapore operate full nodally priced markets (at least for generation) but have limited or no locational variation in transmission pricing. The northeast United States markets utilise nodal pricing with generally flat postage-stamped transmission charges, although PJM has a 'deep connection' (also known as a 'but for') charging regime, which requires connecting generators to pay for the cost of augmentations necessary to ensure their output can reach load at peak times. A chart showing the broad inverse correlation is presented in **Figure 1** below.

Generally speaking, the design of energy market and transmission pricing arrangements in particular jurisdictions can be expected to reflect the materiality of issues faced within those jurisdictions and political tradeoffs between economic efficiency and other objectives. For example, in Great Britain, generation was historically located close to load and predominantly thermal. At the same time, the British network is highly meshed and losses are a smaller component of overall energy cost than in New Zealand. This led to different solutions to those adopted in New Zealand where the network is less meshed.

Figure 1: Degree of locational transmission versus energy pricing



Source: Frontier Economics. We note that some of the points have been changed from an earlier version of this table presented to the TPTG. The changes were made to better reflect the text of the international review report.

2.1.3 Findings of Strata current issues paper

The Strata current issues paper highlights a number of observations and concerns raised by the TPTG, which is made up of industry experts. We note that these were not the unanimous views of the group and some of the observations are contradictory. Notwithstanding this, some of these observations are relevant to the high-level options review, while others are perhaps more relevant to the detailed stages of the review. Below we have attempted to sort of the key observations into those we consider relevant to the high-level options review and those we consider more relevant to the subsequent stages of work on transmission pricing methodology (TPM).

Relevant to high-level options review:

- The pricing principles in Rules 2.1-2.5 potentially conflict with one another. The TPTG has suggested that the Commission considers a review of the pricing principles.
- Nodal pricing signals and the GIT may provide insufficient signals as to the LRMC of locating in particular areas, particularly for generators.
- The beneficiary pays philosophy underlying the HVDC charge is partial (as it falls on SI generators only) and distorts new generator location decisions.
- Potential providers of transmission alternatives must contract with Transpower rather than being directly eligible for a regulated revenue source.

- The TPM does not link transmission prices paid by particular customers to the service levels they request or receive.
- Parties investing in transmission connection assets should receive physical 'capacity rights'.

More relevant to detailed stages of the TPM review:

- Voltage support charges could be included in the TPM, such as by charging directly for reactive power support or interconnection costs on a kVA basis instead of a kW basis.
- Some parties suggested that the current use of non-uniform "N" peaks is inappropriate and that AMD may be a better cost allocator than RCPD.
- Load shifting can presently affect distributed or local generation viability, as can the current use of averaged RCPD for fixed cost recovery. Some parties suggested more regionalisation may be required.
- The appropriate 'depth' of connection charging should be reviewed and definitions clarified.

2.2 Scope of high-level options

An important conceptual first step in deriving 'high-level' options is to distinguish higher-level issues and options from lower levels of issues and options. While this distinction must to some extent be arbitrary – and consideration of lower level issues is often important to choosing between high-level options – the distinction still offers value in helping to defer consideration of consequential matters until there is wider consensus as to the appropriate high-level options to pursue.

Broadly speaking, the approach taken in this report is to treat locational cost allocation issues as high-level and price structure issues as lower level. That is, the focus in this report is on the degree of locational differentiation of transmission charges. Having said that, there are some options (such as augmented nodal pricing – see section 3.3) that explicitly encompass both cost allocation and price structure.

2.3 Relevant policy and regulatory considerations

The selection of high-level options in this report has taken account of the findings of the three reports prepared for the Commission outlined above. As discussed in section 4 below, these reports are also relevant to the formulation of criteria for filtering the options.

In addition to the background papers, the selection of high-level options must also take account of the Commission's objectives for the review. These objectives require that the preferred option must:

- Be consistent with the Commission's principal objectives and specific outcomes as stated in the Electricity Act 1992
- Be consistent with the pricing principles as stated in Part F of the Rules
- Be consistent with the Government's policy for the pricing of transmission services as stated in the Government Policy Statement (**GPS**)
- Take into account practical considerations
- Take into account transaction costs; the preferred high level option should not incur unreasonable transaction costs
- Take into account the desirability for consistency and certainty for both consumers and the industry

While the final three requirements are self-evident, the first three are described further below.

2.3.1 Commission's principal objectives

Section 172N of the Electricity Act 1992 sets out the Commission's principal objective and specific outcomes:

> (1) The principal objectives of the Commission in relation to electricity are—
>
> > (a) to ensure that electricity is produced and delivered to all classes of consumers in an efficient, fair, reliable, and environmentally sustainable manner; and
> >
> > (b) to promote and facilitate the efficient use of electricity.
>
> (2) Consistent with those principal objectives, the Commission must seek to achieve, in relation to electricity, the following specific outcomes:
>
> > (a) energy and other resources are used efficiently:
> >
> > (b) risks (including price risks) relating to security of supply are properly and efficiently managed:
> >
> > (c) barriers to competition in the electricity industry are minimised for the long-term benefit of end-users:
> >
> > (d) incentives for investment in generation, transmission, lines, energy efficiency, and demand-side management are maintained or enhanced and do not discriminate between public and private investment:
> >
> > (e) the full costs of producing and transporting each additional unit of electricity are signalled:
> >
> > (f) delivered electricity costs and prices are subject to sustained downward pressure:
> >
> > (g) the electricity sector contributes to achieving the Government's climate change objectives by minimising hydro spill, efficiently managing transmission

> and distribution losses and constraints, promoting demand-side management and energy efficiency, and removing barriers to investment in new generation technologies, renewables, and distributed generation.

The principal objective refers to the efficiency, fairness, reliability and environmental sustainability of electricity supply. The specific objectives emphasise the achievement of economic efficiency across various electricity operational and investment decisions.

2.3.2 Part F Pricing Principles

Section IV of Part F of the Electricity Governance Rules (Rules) contains transmission pricing principles to be applied by Transpower and the Commission (Part F principles):

> 2.1 the costs of connection and use of system should as far as possible be allocated on a user pays basis;
>
> 2.2 the pricing of new and replacement investments in the **grid** should provide beneficiaries with strong incentives to identify least cost investment options, including energy efficiency and demand management options;
>
> 2.3 pricing for new generation and load should provide clear locational signals;
>
> 2.4 sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions made by **grid** users;
>
> 2.5 the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise network constraints; and
>
> 2.6 transmission pricing for investment in the **grid** should recognise the linkages with other elements of market pricing (including the design of the **financial transmission rights** regime under section V, and any revenues from **financial transmission rights**).

These principles appear to be directed at promoting various aspects or dimensions of economic efficiency. For example, recovering at least new connection costs on a 'user pays' basis is consistent with general principles of marginal cost pricing – a party is required to pay a sum at least equal to the value of the best foregone alternative use of the resources required to provide the relevant good or service. Similarly, recovering sunk costs in a manner that has minimal impact on parties' future decisions is consistent with the truism that the utilisation of sunk investments – by definition – involves no opportunity cost up to the point where demand exceeds available capacity and needs to be rationed.

Rule 2.2 requires that the pricing of new and replacement grid investments should provide beneficiaries with strong incentives to identify least-cost investment options. Under the present New Zealand electricity arrangements, the Grid Investment Test (GIT) is the primary tool for promoting efficient adoption of transmission alternatives.

In our view, the idea of recovering the cost of <u>future</u> grid investments (ie new and replacement investment) in such a way as to incentivise private adoption of efficient transmission alternatives is reflective of a regime in which all the following conditions are met:

- participants determine (or at least strongly influence) the nature, location and timing of grid investments, rather than investment being determined through a centralised planning process.
- the beneficiaries of grid investment can be clearly identified.
- to the extent beneficiaries are required to pay for new grid investment, they receive some form of property rights over the returns of the investment.[6]

These conditions are not universally met under the current transmission regulatory arrangements.[7] Participants can indirectly influence the nature, location and timing or grid investments through their own investment decisions, but grid investment is ultimately determined by Transpower and the Commission.

Furthermore, there is a practical problem with recovering the cost of future grid investment in a certain way when these costs may not be included in Transpower's allowed regulated revenues.

2.3.3 Government Policy Statement

Part 99 of the Government Policy Statement on Electricity Governance states that the Commission should ensure that the following principles are applied by Transpower in developing any transmission pricing methodology and by the Commission in approving it:

- the costs of connection should as far as possible be allocated on a user-pays basis.
- the pricing of new and replacement investments in the grid should provide beneficiaries with strong incentives to identify least-cost investment options, including distributed generation, energy efficiency and demand management options, and combinations of those options.
- pricing for new generation and load should provide clear locational signals.
- sunk costs should be allocated in a way that minimises distortions to production/consumption and investment decisions by grid users and consumers.

6 See, for example, Hogan, W.W., *Market-based transmission investments and competitive electricity markets*, August 1999, Centre for Business and Government, John F. Kennedy School of Government, Harvard University, Cambridge MA, pp.17-20, available here.

7 Grant Read contends that in an 'ideal contractual framework' (which Read concedes is not currently a viable option for New Zealand), a beneficiary pays approach would be appropriate. See Read, E.G., *Locational Transmission Pricing: A Formulaic Approach, prepared for Mighty River Power*, Draft 1.3, 26 February 2007 (Read (2007)), para 30, pp.17-18.

- the overall pricing structure should include a variable element that reflects the marginal costs of supply in order to provide an incentive to minimise grid constraints.

We note that these principles closely resemble those contained in Part F of the Rules. One of the key differences is that Part F requires that both connection and use of system costs be allocated as far as possible on a user-pays basis whereas the GPS only refers to the costs of connection. In our view, the GPS formulation is preferable, as it avoids the potential for conflict between Part F pricing principle 2.1 and the other pricing principles. This is also discussed further below.

Another key difference between the Part F principles and the GPS is the inclusion of 2.6 in the Part F principles. This requires regard to be had to the role of nodal pricing and the design and application of a financial transmission rights (FTR) regime. In our view, this is a helpful inclusion as it explicitly allows for recognition of the signalling role of nodal pricing and the cost recovery role of transmission rentals.

2.3.4 Tradeoffs and compromises

In virtually all circumstances, it will not be possible to apply all of the pricing principles in Part F or the requirements in the GPS equally. Indeed, as acknowledged in Rule 3.2 of Part F, conflicts may arise in the application of the pricing principles. This point was also raised by the TPTG (see section 2.1.3 above). In these circumstances, the role of the Commission is to resolve conflicts with the objective of promoting the Commission's principal objective (as discussed above). This will typically require trade-offs to be made between the principles when applying them to the development of suitable high-level options.

For example, a transmission pricing methodology could be developed to perform an investment signalling role in order to promote Part F principle 2.3. But this may mean it becomes necessary to recover sunk costs in a manner that departs from least-distortionary cost recovery (thereby disturbing Part F principle 2.4). Similarly, pricing grid investment in a manner that provides beneficiaries with strong incentives to identify least-cost alternatives (Part F principle 2.2) suggests that should such alternatives not be adopted, the beneficiaries of grid investment be made to pay its costs. However, this may conflict with the need to recover sunk costs in a least-distortionary manner (Part F principle 2.4) or on a user-pays basis (Part F principle 2.1).[8]

[8] Even under Read's 'ideal contractual framework' approach (see footnote 7), it would be hard to reconcile Rules 2.1 and 2.2 if 'users' turn out to be different from the initial 'beneficiaries'.

The following section sets out four high-level options that each reflect a compromise between the various pricing principles in Part F and the GPS, as well as practical considerations.

3 High-level options

Key concepts

In addition to the status quo transmission pricing arrangements, we have identified three other high-level options that are worthy of further investigation and consultation. These three other options are:

- 'Tilted' postage stamp approaches
- Augmented nodal price signals
- Load flow-based approaches

Further to these high-level options, there are three other key issues arising in the consideration of transmission pricing methodology. These are:

- Approach to setting connection charges, which could involve a 'deep connection' (or 'but for') charging approach, as employed in several jurisdictions in the United States
- Treatment of transmission alternatives
- Linking transmission pricing with service quality

The current transmission pricing regime reflects a view that there is little need for transmission pricing to provide additional locational signals for participant investment decisions on top of nodal pricing in the energy market and charging participants for the spur line connection assets. All the other approaches are predicated on these existing signals being insufficient to promote efficient participant investment decisions.

The tilted postage stamp approach is intended to provide broadly appropriate locational signals to generators and loads. Assuming the historical pattern of network flows continues into the future, it would mean imposing higher charges on generators in the South Island and loads in the North Island and lower charges on generators in the North Island and loads in the South Island.

The augmented nodal price signals option seeks to directly address the deficiencies in nodal energy prices created by excessive or premature network investment. Under this regime:

- Transmission charges should be highest for those generators and loads that benefit most from excessive or premature network investment
- Transmission charges should be lowest for those generators and loads that are made most worse off from excessive or premature network investment

Load flow-based transmission pricing options involve a process of attributing network costs to participant connection points based on an engineering estimation of the network assets 'used' to convey electricity from points of injection to points of withdrawal. Load flow approaches can be based on the topology of the existing network as in Australia (cost reflective network pricing or CRNP) or on forward-looking network development costs, as in Great Britain (investment cost related pricing or ICRP). The CRNP approach can produce perverse pricing outcomes that strongly diverge from LRMC, although this can be mitigated by modifying the methodology to take account of patterns of network utilisation. Load flow modelling lacks transparency but is replicable. It is feasible that this approach could achieve similar results to the tilted postage stamp approach from a sounder analytic base and without having to rely on the somewhat arbitrary assumptions required for the tilted postage stamp approach.

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Transmission alternatives should generally face similar transmission pricing signals as grid-connected loads and generators. However, it may be worth clarifying the treatment of distributed or local generation.

In the past the Electricity Commission has considered various options for strengthening the link between transmission service quality and compensation or liability arrangements applying between Transpower and participants. In this context, there are a number of options currently under consideration.

This section outlines the four high-level options and potential variations around them that we consider worthy of further investigation and consultation. The options include the status quo arrangements, potentially with modifications (section 3.1). In addition, a range of pricing approaches is available if nodal pricing is considered to provide inadequate locational signals for new generators and/or loads. These tend to fall in one of the following three categories:

- 'Tilted' postage stamping approaches (Option 2 – see section 3.2)
- Augmented nodal price signals (Option 3 – see section 3.3)
- Load flow-based approaches (Option 4 – see section 3.4)

In addition, this section makes some observations on issues and options regarding connection charging (section 3.5), the treatment of transmission alternatives (section 3.6) and the link between service quality and pricing (section 3.7).

3.1 Option 1 – Status quo

3.1.1 Outline

The requirements of the existing transmission pricing methodology are contained in Schedule F5 of the Rules. The existing regime comprises the following charges:

- Connection charges – payable by all connected parties in respect of 'connection assets', as defined in sections 3.54-3.61.
- Interconnection Charge – payable by loads. The charge payable by a given load is a function of both the postage-stamped Interconnection Rate ($/kW) and its weighted-average Regional Coincident Peak Demand (RCPD).
- HVDC Charge – payable by South Island generators. The charge payable by a given generator is a function of both the postage-stamped DC rate (DCR) ($/kW) and its 12 peak injections over a historical period.

Thus, under the existing regime, loads pay for the AC interconnected grid while only South Island generators pay for the HVDC assets. All parties pay for their connection assets.

3.1.2 Evaluation

The existing transmission pricing regime reflects one approach to balancing the Part F pricing principles. As noted above, the Connection Charge reflects the user-pays philosophy embodied in Rule 2.1. The Interconnection Charge reflects an attempt to recover sunk costs in a least-distortionary manner (Rule 2.4), while the HVDC Charge reflects a locational signalling priority – that is, to promote generation investment in the North Island as against the South Island (Rules 2.2 and 2.3).

The appropriateness of the existing regime largely depends on the extent to which nodal pricing sends sufficient locational investment signals to investors in generation and load projects. The clear inference to draw from the basis of the Interconnection Charge in particular is that new loads do not require further incentives to locate in unconstrained or generation-rich areas than already provided by energy market prices. While the HVDC Charge promotes new generation investment in the North Island as compared to the South Island, it provides no further (ie intra-Island) locational signal for new generators.

Therefore, <u>if</u> it is the case that existing nodal pricing signals do provide adequate locational investment incentives, the key reform to the existing regime would be to modify or abolish the HVDC Charge so as to remove the disincentive it imposes on new generation in the South Island. HVDC revenues could instead be recovered by imposing postage stamped charges across all generators and/or all loads (although this will have wholesale price and distributional effects that may be considered unappealing).

Alternatively, if existing nodal pricing signals do not provide adequate locational signals, it may be worth extending the locational recovery of core grid costs from generators and/or loads to include at least some HVAC costs.

In this context, Grant Read contends that the only way expected nodal price differentials can provide sufficient locational signals to participants – thus permitting the use of a flat postage stamp approach to recover existing sunk network costs – is under his preferred 'contractual' approach to funding new transmission investment.[9] This is because, according to Read, nodal pricing will only provide sufficient locational signals under the following two conditions:[10]

- A 'complete market regime', in which participants expect to face large nodal price differentials if augmentation does not proceed and where participants expect to pay the full cost of augmentation that does occur.
- Transmission augmentation or expansion only occurs where it is economic. Read suggested that under the current regime, expansion occurs in advance of when it is economic due to the need to satisfy reliability criteria. If this occurs, nodal prices will not adequately signal investment location and an additional charge will be required.

The second of these conditions is consistent with Biggar and the discussion in section 2.1.1 above, as well as with Frontier's efficient pricing theory report prepared for the Commission. However, the first of these conditions is less well accepted and understood. So long as transmission investment occurs efficiently and nodal prices are allowed to rise enough to accurately reflect scarcity, it is not clear why appropriate locational signals will be lacking even if the participants that benefit from augmentation (through reduced nodal price differentials) are not required to pay the costs of augmentation.

A different way of thinking about this issue is to consider what would happen if all transmission investment was merchant-driven. Such a merchant transmission investment will need to recover its costs from the incremental congestion and marginal loss rentals accruing to its link (or 'foundation' contracts that effectively allocate ownership over these rentals). Over time, as demand grows, congestion

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9 Read (2007), para 35, p.19.

10 Read uses a hypothetical example to emphasise these conditions: [The nodal] price differential alone will not cover the full cost of expansion, **particularly if expansion is triggered by reliability criteria external to the market** and if loads in [the constrained importing region] do not face the full cost, eg if they share it with loads in [the unconstrained exporting region], they do not face the full consequences of their actions, and do not have adequate incentives to restrain load growth, an peak load in particular. Conversely, loads in [the unconstrained exporting region] will face a transmission price component which discourages load growth there, whereas, in fact, that growth implies no increase in transmission costs, and the optimal signal for them is clearly zero. (p.23) [Emphasis added]

on the link will rise and the merchant investor will earn revenues greater than losses. In effect, generators at the exporting node of the line and loads at the importing node of the line will 'pay' for the investment through price differentials.[11] This is conceptually similar to how the fixed costs of new merchant generation plant are recovered in an energy-only market – through spot market prices.[12] Read's proposition that benefitting participants need to pay the cost of augmentations in order to face appropriate locational signals amounts to beneficiaries paying for network investment twice – first through rising nodal spot price differentials and second through an allocation of fixed costs. The only way double-charging can be avoided under this approach is if the beneficiaries who are required to pay the costs of a transmission augmentation effectively 'own' the transmission rentals that accrue over time as congestion on 'their' link grows.

Thus, in our view, whether current nodal prices do or not provide adequate locational signals – and hence whether the existing regime is broadly appropriate – depends on the extent to which the conditions highlighted in the efficient pricing theory paper hold. This, in turn, is an empirical question and is discussed further in section 4.1 below.

Finally, although the existing Connection Charge is commonly referred to as reflecting a 'deep' charging approach, it is more accurately described as a spur line charging approach, where participants are required to contribute towards the cost of spurs out from the core meshed grid. Depending on where participants locate, they may be required to pay for extensive or few assets, even if these assets are already in place. This could distort locational decisions by encouraging connection at the core grid even if spur line assets exhibit spare capacity.[13]

In terms of the structure of all the existing charges (Connection, Interconnection and HVDC), we note that the basis of all charges is a measure of peak injections or withdrawals (demand). As noted by Grant Read, transmission charges based on present or historical generation or consumption (whether MWh or peak MW) will tend to distort the operational signalling role of nodal prices:

> It is simply not possible to simultaneously achieve optimal short and long signalling [sic] in the context of any pricing regime employing such mechanisms, and the best we can

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11 Assuming zero transactions costs and no market power, these rentals should fund efficient levels and types of transmission investment.

12 See Stoft, S., *Power system economics: Designing markets for electricity*, New York, US: Wiley-Interscience (2002), pp.121-132, as discussed in Frontier's efficient pricing theory report.

13 See, for example, Rious et al (2008) as cited in Biggar, D., *A framework for analysing transmission policies in light of climate change policies, Final*, 16 June 2009 (Biggar (2009)), pp.22-23, available from the AEMC website here.

> hope for is to find a reasonable compromise with respect to the degree of distortion implied by each.[14]

However, Read goes on to note that focussing on peak charges – as does the existing TPM – represents such a reasonable compromise. If further steps were to be taken to minimise the impact of transmission charges on participants' operational decisions, another potential reform would be to impose transmission charges according to a fixed metric, such as the nameplate or contracted capacity of the relevant load or generator. While this would tend to favour plant with relatively high capacity/load factors, it would at least avoid distorting operational decisions.

3.2 Option 2 – 'Tilted' postage stamp approaches

3.2.1 Outline

On the basis that nodal pricing will provide insufficient locational signals, Grant Read has proposed a 'tilted' postage stamp approach for recovering regulated transmission revenues.[15] Under this approach, charges are higher for loads in importing regions and lower for loads in exporting regions. If future load growth in New Zealand follows historical trends, Read suggests that charges should be higher for loads in the North Island than loads in the South Island. Read also proposed that the tilted postage stamp charge could also apply to generators in an inverse manner. That is, generators in the North Island face a lower charge (or even a subsidy) than generators in the South Island.[16] The need for such differentiated charges is even greater if the transmission system is augmented on the basis of deterministic reliability criteria.[17]

Further, such charges ought not be structured as a least-distortionary 'optimal tax', but in a manner designed to encourage attenuation of load growth – such as in the form of a peak demand charge.[18]

Further, Read notes that the LRMC of increasing load at a given point is unlikely to remain constant, but to exhibit cycles over time due to the lumpiness of transmission investment. For example, the LRMC of load growth in importing regions is likely to be relatively high as the network becomes more congested and new investment is required, but is likely to fall immediately following transmission investment and the creation of spare network capacity. Read suggests that the degree of 'tilt' in postage stamp charges should follow the

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14 Read (2007), para 28, pp.16-17.

15 See Read (2007).

16 Read (2007), section 3.4, paras 58-64, pp.29-32.

17 Read (2007), para 52, pp.25-26.

18 Read (2007), para 55, pp.28-29.

magnitude of nodal price differentials by becoming steeper as congestion and nodal price differentials rise and shallower following transmission investment and the flattening of nodal prices.[19]

In his paper for Mighty River Power, Read also put forward a number of alternative tilted postage stamping approaches geared towards addressing various real-world complexities. Options include:

- A zonal charge postage-stamped charge based on the grouping of participants' grid exit points (GXPs) within geographic zones
- An Island-wide postage-stamped charge – effectively, this would treat each Island as a pricing zone[20]

More complicated approaches are possible, in which network branches and loops are taken into account.

3.2.2 Evaluation

As with other locational pricing methodologies, the case for a tilted postage stamp approach is contingent on the extent to which nodal prices are considered to provide insufficient investment signals.

However, unlike the augmented nodal signals approach (see section 3.3 below), which seeks to directly compensate for the muting of nodal price signals caused by sub-optimal transmission investment, Read considers a tilted postage stamp approach as a second-best approximation of what he considers to be an 'ideal' pricing regime.

Another difference between the augmented nodal signals approach and Read's tilted postage stamp is that the augmented nodal approach is only proposed to the extent that the network is inefficiently overbuilt, whereas Read contends that a locational transmission pricing signal is necessary even if transmission augmentation occurs efficiently.[21]

Nevertheless, the underlying rationales for the titled postage stamp approach and the augmented nodal approach are similar – that for one reason or another, nodal prices will tend to 'under-signal' the costs of remote locational decisions.

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19 Read (2007), paras 74-75, p.36.

20 Read (2007), section 3.7, paras 81-109, pp.38-47.

21 Read (2007), footnote 21, p.26.

3.3 Option 3 – Augmented nodal price signals

3.3.1 Outline

As explained in Frontier's efficient pricing theory report, the inadequacy of nodal prices for providing locational signals could arise due to the inefficient over-building of the transmission system (which artificially 'mutes' nodal price differentials).[22] "Overbuilding" in this context refers to transmission augmentations undertaken in a manner that is not consistent with the maximisation of market benefits over time.

The efficient pricing theory report explained that there were three key potential reasons for transmission investment to be built to a level that causes nodal price differentials to be lower than the averaged LRMC of transmission augmentation:

- Economies of scale – may lead to 'lumpy' transmission augmentation that creates a divergence between nodal price differentials and the incremental cost of augmentation. However, this does not imply inefficient over-building within the technological scope of the available options.

- Inaccurate pricing of supply security – in a transmission planning framework that utilises deterministic reliability standards, transmission investment required to meet those standards may not be net beneficial based on an appropriate value attributed to avoiding unserved energy. This problem will be compounded if nodal prices are not permitted to rise to levels that accurately reflect the scarcity of supply at times it occurs.

- Over-caution of network planners – may lead to too much transmission investment or investment occurring too early. In some cases, this may be justifiable in light of the 'asymmetry' of costs between network over- and under-investment.

The efficient pricing theory report further explained that the logical response to the over-building of the transmission system would be to amplify or otherwise augment nodal price differentials.[23]

A framework for such a pricing regime was developed in the efficient pricing theory report prepared by Frontier for the Commission. This framework specified that:

- Transmission charges to <u>generators</u> should be <u>highest</u> for those generators that <u>benefit most</u> from excessive or premature network investment (e.g. generators in generation-rich areas who benefit through nodal prices being

22 See section 4.4, pp.14-16.

23 See section 4.4.2, pp.17-18.

higher than would otherwise be the case). Such charges could be imposed after the excessive or premature investment has been committed and would reflect the value of the benefit to existing generators accruing due to the excessive or premature nature of the investment.

- Transmission charges to loads in the same (generation-rich) areas should be relatively low, as those loads are effectively penalised by higher nodal prices caused by over-investment in the network.
- Transmission charges to generators should be relatively low (or negative) in areas where generators are most worse off due to excessive or premature network investment (e.g. generators located in load-rich areas, who experience lower nodal prices than would otherwise be the case).
- Likewise, transmission charges to loads in load-rich areas should be relatively high to reflect the value of the benefit these loads receive through nodal prices being lower than would be the case if transmission investment was undertaken efficiently. Such charges could be imposed after the excessive or premature investment has been committed and would reflect the value of the benefit to existing loads accruing due to the excessive or premature nature of the investment.

Another implication of this approach is that transmission charges to different participants *at any given location* should be different depending on the timing of their consumption or production. This means that

- Consumers with low load factors and high coincident peak demands *and*
- Generators with low capacity factors and high coincident peak injections

will be charged more under this approach than consumers or generators with high load or capacity factors, respectively.

In summary, this suggests that in a market with over-investment in the network, and without nodal scarcity pricing, an efficient transmission pricing regime may need to impose relatively high charges on:

- new (or expanded) loads in areas of the network *and* at times during the day and year when drawing power from the network is expected to contribute to the case for future network augmentation; and
- new (or expanded) generators in areas of the network *and* at times during the day and year when injecting electricity is expected to contribute to the case for future network augmentation.

A stylised illustration of this approach is set out in **Figure 2** below.[24] This figure shows that, over time, growing transmission congestion leads to nodal price

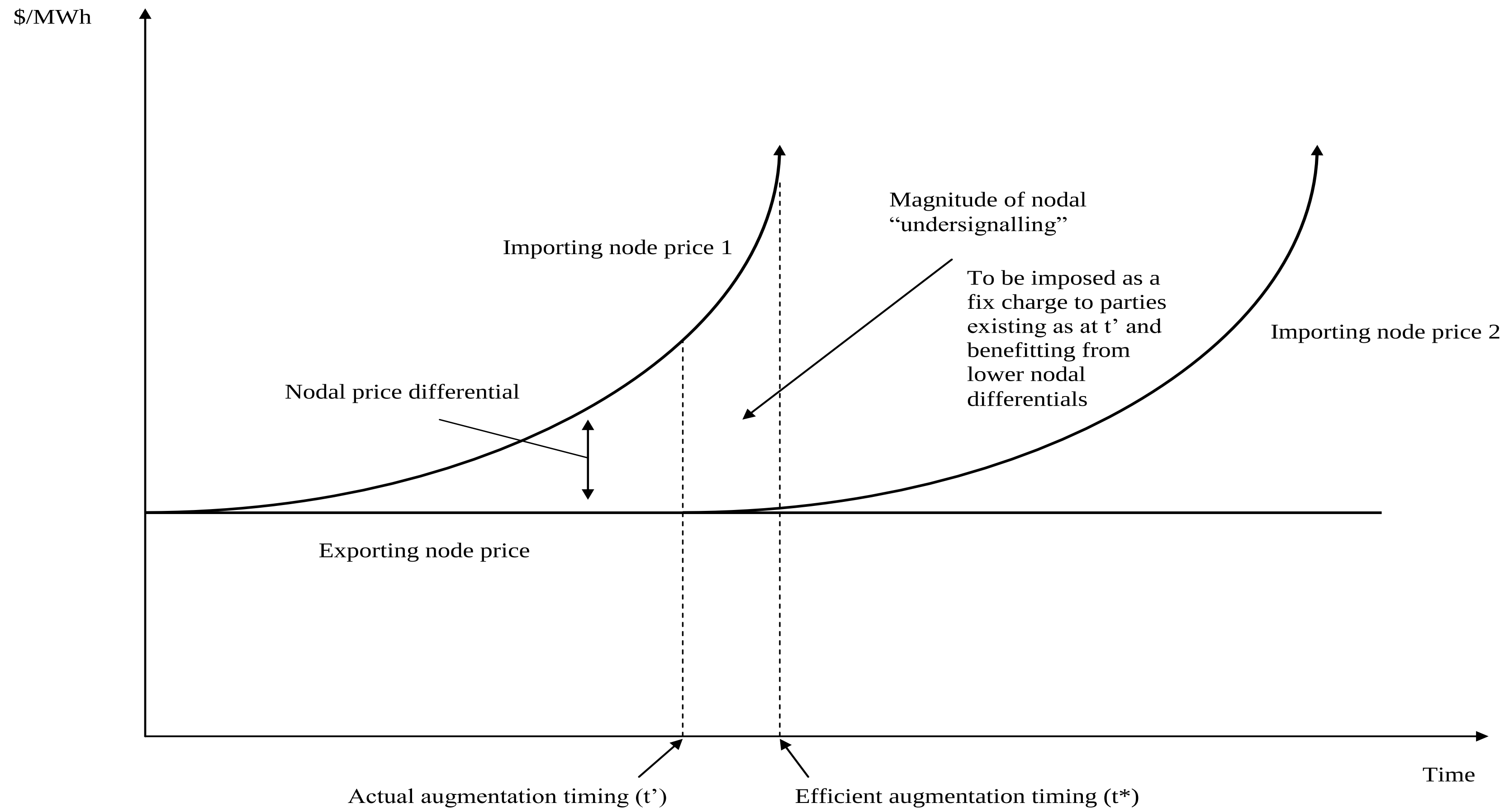
24 Note that in this stylised example, for the same of simplicity, it is assumed that augmentation does not affect the price at the exporting node.

separation between the exporting node price (which remains low) and the importing node price (which rises as the severity of congestion increases). If transmission investment was efficient, augmentation of the link between the nodes would occur at time t*. Immediately following the augmentation, the nodal price differential would collapse to zero. Over time, nodal prices would again begin to separate as congestion again increased on the augmented link. In this scenario, loads at the importing node would face prices that rose exponentially until time t*.

By contrast, if transmission investment was to proceed before it was efficient, at time t', the nodal price differential would collapse at time t' instead of t*. Therefore, the price at the importing node would not rise as high as it would if transmission investment was undertaken when it was efficient, at t*. This implies that loads at the importing node would face weaker nodal pricing signal than they would if transmission investment occurred efficiently.

The objective of the augmented nodal price signalling approach is to levy on customers benefitting from premature transmission investment charges that reflect the magnitude of the undersignalling they experience due to that premature investment. In the example below, the charge to importing node loads would reflect the area between the "Importing node price 1" curve and the "Importing node price 2" curve, between t' and t*. This charge would need to be imposed as a fixed charge on loads at the importing node that exist at time t'. There is no efficiency objective served by imposing such charges on new loads that locate after t', as by that stage, the premature network investment has already been sunk.

Figure 2: Augmented nodal price charges



Source: Frontier Economics

At the same time, it is important to ensure that transmission charges are not structured on the basis of usage of the transmission network, in terms of MWh injected or withdrawn from the grid.[25] Usage-based charges operate as a tax on usage, deterring the utilisation of sunk assets. Dynamic efficiency requires that charges influence participants' generation and load investment decisions but minimise their impact on operational decisions, such as electricity consumption and generator bidding/dispatch. Better options could include:

- Charges based on the rated capacity of the relevant generation or load facility (as suggested above in relation to modifications to the existing regime) *or*
- Charges based on independent or coincident peak demand or injections, with the peaks determined on a basis unlikely to interfere with day-to-day operational decisions.

As discussed in the efficient pricing theory paper, Biggar also makes a number of other points on the formulation of transmission charges that are relevant to the New Zealand context:[26]

- First, the impact of charges depends on the spatial differentiation in the charges, rather than their absolute level.
- Second, from an efficiency perspective, the net allocation of costs to generators versus loads is essentially arbitrary[27] (although both sides of the market need to face locationally differentiated charges).
- Third, transmission charges – being unhedgeable – should be as predictable and stable as possible to enable investors to make robust decisions.

3.3.2 Evaluation

Clearly, the informational and predictive requirements of setting charges based on the augmented nodal signals approach are considerable. Specifically, it would be necessary to develop a theoretically efficient transmission grid in which lifetime constraint and loss rentals recovered the fixed costs of the grid. It would then be necessary to determine the difference between the theoretically efficient nodal prices and the nodal prices that prevailed in practice. These differences would be used to derive transmission charges that would augment the prevailing nodal pricing signals.

The difficulties of constructing such augmented nodal prices need to be weighed up against the benefits of imposing such differentiated transmission charges, which in turn will depend on the extent to which the transmission network is

25 Biggar (2009), pp.16-17.

26 Biggar (2009), pp.23-24.

27 This is not to say the net allocation of costs is unimportant from a distributional perspective.

overbuilt by comparison to strict economic efficiency criteria. Where this is the case, the augmented nodal approach could be expected to produce the most theoretically accurate economic signals of all the options outlined in this report.

3.4 Option 4 – Load flow-based approaches

3.4.1 Outline

As discussed in the international pricing review report prepared by Frontier for the Commission, some jurisdictions have used load flow-based approaches to develop charges that aim to broadly signal the LRMC of locational decisions. Indeed, the Strata draft report on historical transmission pricing methodologies noted that a load flow-based approach was used in New Zealand until 1999.[28]

Load flow approaches involve a process of attributing network costs to participant connection points based on an engineering estimation of the network assets 'used' to convey electricity from points of injection to points of withdrawals. Load flow analysis is a well-accepted and understood approach to simulating power flows and network loading under various system operating conditions.

Load flow approaches can be based on the topology of existing network asset costs, as in the Australian NEM or on forward-looking network development costs, as in the Great Britain BETTA market (see below).

Existing network costs – NEM approach

Regulated shared transmission network costs in the NEM are recovered through Transmission Use of System (TUoS) charges. These charges comprise a postage stamp component, as well as a locational component, with the former usually comprising at least half allowable shared network revenues.

Schedule 6.4 of the former National Electricity Code described the key features of the cost reflective network pricing (CRNP) cost allocation methodology.[29] CRNP is a process for allocating costs to the users of the shared transmission network. This process can be summarised as follows:

A 'cost' is assigned to each series element of the network (essentially to each transmission line, transformer and series reactor). This assignment is based on allocating a share of the transmission business's regulated revenue to individual elements based on the ratio of the optimised replacement cost (ORC) of the network element to the ORC of all network elements used to provide prescribed use of system services.

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28 Para 17(a)(ii), p.8.

29 See Chapter 6, Schedule 6.4, section 5 in the Code, available here.

Then the usage made of each element by the load at each connection point is determined through several steps:

1. Determine the baseline allocation of generators to loads using a 'fault contribution matrix'.
2. Determine the allocation of generators to loads over a range of actual operating conditions from the previous financial year. The range of operating scenarios is chosen so as to include the conditions that result in most stress on the transmission network and for which network investment may be contemplated. For each operating scenario selected:
   - a constrained allocation of generation to loads matrix must be developed, in which generation is allocated to serving loads on the basis of the fault contribution matrix.
   - load flow analysis techniques are used to solve for network flows and to calculate the sensitivity of flows on each network element resulting from incremental changes in each load.
   - the sensitivities are weighted by load to derive a 'flow component' magnitude in each network element due to each load for that hour.
   - the relative utilisation of each network element by each load is calculated from the 'flow component' magnitudes, using only the flow components in the direction of the prevailing line flow.
3. When all the selected operating scenarios have been assessed, allocate the individual network element costs to loads on a pro rata basis using the maximum 'flow component' that each load has imposed on each network element across the range of operating conditions considered.
4. Determine the total costs allocated to each load by summing the individual locational network element costs allocated to each load.

The end result is an amount of regulated revenue to be collected from each transmission connection point. A separate calculation is made to convert this revenue amount into usage charge rates to be applied at the connection point.

Schedule 6A.3 of the new National Electricity Rules no longer describe CRNP in as much detail, preferring to use a 'principles-based' approach to cost allocation. However, the new Rules deliberately do not prevent transmission businesses from continuing to use CRNP to allocate a proportion of their allowed regulated revenues.

Forward-looking network costs – BETTA approach

National Grid's methodology for setting its Transmission Network Use of System (TNUoS) is set out in its Statement of Use of System charging methodology (Statement).[30] The basis of charging to recover allowed regulated

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30 National Grid, *The Statement of the Use of System Charging Methodology, Effective from 1 April 2009*, available here.

revenue is the Investment Cost Related Pricing (ICRP) methodology. National Grid describes the rationale for its pricing regime as seeking to signal the incremental costs of supplying users:

> 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.[31]

The TNUoS tariff compromises a locational and a non-locational component. The locational component utilises the DC Loadflow ICRP based transport model. With the advent of the BETTA market, the DCLF model now incorporates England, Wales and Scotland.

The DCLF ICRP transport model calculates the marginal costs of investment in the transmission system which would be required as a consequence of an increase in demand or generation at each connection point or node on the transmission system, based on a study of peak conditions on the transmission system. One measure of the investment costs is in terms of MWkm. This is the concept that ICRP uses to calculate marginal costs of investment. Hence, marginal costs are estimated initially in terms of increases or decreases in units of kilometres (km) of the transmission system for a 1 MW injection to the system.

The transport model requires a set of inputs representative of peak conditions on the transmission system. These inputs include all nodal generation and demand data as well as information about all the transmission circuits between the nodes (in terms of voltage, technology and line lengths). This is all used to derive 'circuit expansion factors'. See the Box below for more details on the workings of the transport model.

More details on the ICRP methodology are available in chapter 2 of the Statement and a worked example is set out in Appendix TN-1 of that document.

Given the requirement for relatively stable cost messages through the ICRP methodology and administrative simplicity, nodes are assigned to zones. Typically, generation zones will be reviewed at the beginning of each price control period with another review only undertaken in exceptional circumstances. Any rezoning required during a price control period will be undertaken with the intention of minimal disruption to the established zonal boundaries. Demand zone boundaries have been fixed and relate to the GSP Groups used for energy market settlement purposes. Again, more details are contained in the Statement.

31 Statement, para 1.6, p.10.

Box 1: ICRP Transport Model

The transport model takes the inputs described above and first scales the nodal generation capacity uniformly such that total national generation (the sum of contracted injection capacities) equals total national peak winter demand. The model then uses a DCLF ICRP transport algorithm to derive the pattern of flows based on the network impedance required to meet the nodal demand using the scaled nodal generation, assuming every circuit has infinite capacity. It then calculates the resultant total network MWkm, using the relevant circuit expansion factors as appropriate. Using this baseline network, the model calculates – for a given injection of 1MW of generation at each node, with a corresponding 1MW offtake (demand) at the reference node (near London[32]) – the increase or decrease in total MWkm of the whole network. Given the assumption of a 1MW injection, for simplicity the marginal costs are expressed solely in km. This gives a marginal km cost for generation at each node.[33] The marginal km cost for demand at each node is equal and opposite to this nodal marginal km for generation and this is used to calculate demand tariffs. Note the marginal km costs can be positive or negative depending on the impact that the injection of 1MW of generation has on the total circuit km. Using a similar methodology, the local and wider marginal km costs used to determine generation TNUoS tariffs are calculated by injecting 1MW of generation against the node(s) the generator is modelled at and increasing by 1MW the offtake at the reference node.

Source: National Grid, *The Statement of the Use of System Charging Methodology, Effective from 1 April 2009*, available here.

One key difference between the CRNP used in Australia and the ICRP approach used in Great Britain is the purported use of forward-looking costs rather than existing network costs. The National Grid methodology uses the 'expansion constant' to convert the marginal km figure derived from the transport model into a £/MW signal.

The expansion constant, expressed in £/MWkm, represents the annuitised value of the transmission infrastructure capital investment required to transport 1 MW over 1 km. Its magnitude is derived from the projected cost of 400kV overhead line, including an estimate of the cost of capital, to provide for future system expansion. The circuit expansion factors referred to above are derived from the expansion constant – for each circuit type and voltage, an individual calculation is carried out to establish a £/MWkm figure, normalised against the 400KV overhead line (OHL) figure.

The transmission infrastructure capital costs used in the calculation of the expansion constant are provided via an externally audited process. They also include information provided from all transmission owners. They are based on historic costs and tender valuations adjusted by a number of indices (e.g. global price of steel, labour, inflation, and so on.). The objective of these adjustments is

32 East Claydon in Buckinghamshire, about 80 km north-west of central London.

33 Although note that the calculation of generation tariffs considers local and wider cost components.

to make the costs reflect current prices, making the tariffs as forward looking as possible. The calculation of the expansion constant also relies on a significant amount of transmission asset information, much of which is provided in the Seven Year Statement.

3.4.2 Evaluation

As noted above, load flow-based pricing approaches seek to signal the LRMC of the network to market participants. However, one issue that has arisen, at least with respect to CRNP, is the extent to which it accurately proxies LRMC.

In 1999, as part of the National Electricity Code Administrator's (NECA's) Transmission and Distribution Pricing Review, consultants Ernst & Young critiqued CRNP as a proxy for a true LRMC charge. Ernst & Young observed that CRNP:

> …can only determine LRMC based prices accurately if the transmission system is fully utilised at the time of the calculation and remains fully utilised at all times into the future. Restated this requires that the increments of transmission capacity are closely matched to the load increases. The extent to which inappropriate price signals would be generated by a CRNP type method will be a function of the extent to which the actual situation departs from the above "ideal".
>
> For most practical transmission systems, neither of the above conditions is generally achieved, fundamentally because load grows relatively slowly in relation to the capacity of new transmission, and it is neither economic or even technically possible to add small increments of transmission. Nevertheless a large, heavily meshed transmission system with a reasonable level of load growth will more closely approximate the ideal conditions described above, and in these circumstances it may be possible to derive a reasonable estimate of the future LRMC costs from the costs of the existing assets. The situations where significant departures from the ideal conditions are likely is in remote areas of the transmission system, particularly where utilisation is low and the growth in demand is small. [34]

In particular, Ernst & Young noted that CRNP cost allocation can produce perverse pricing outcomes that strongly diverge from LRMC both where:[35]

- The transmission network has been **recently augmented** and as a result is **lightly loaded**. In such cases, the LRMC of network use is likely to be low due to the large degree of spare network capacity. However, CRNP-based charges may be high due to the high cost of the assets being used to serve the relevant loads.

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34 Ernst & Young, "The cost reflective network pricing algorithm: role and refinements in transmission pricing", pp.73-74 in NECA, *Transmission and Distribution Pricing Review, Final Report, Volume II*, July 1999, available here.

35 Ernst & Young, "The cost reflective network pricing algorithm: role and refinements in transmission pricing", pp.49-50 in NECA, *Transmission and Distribution Pricing Review, Final Report, Volume II*, July 1999, available here.

- The transmission is **heavily utilised** and **augmentation is imminent**. In such cases, the LRMC of network use is likely to be high due to the imminent need for augmentation. However, CRNP-based charges may be low due to the low historical costs of the assets being used to serve the relevant loads.

These issues fundamentally arise due to the economies of scale or lumpiness of transmission investment.

As a result of these shortcomings, NECA proposed a 'utilisation-adjusted' CRNP approach. This approach adjusts the network element costs to be recovered in a locational manner based on the utilisation of the relevant network elements. Low utilisation means that the LRMC of network usage is likely to be relatively low, as the need for network augmentation is likely to be some way off in the future. Conversely, high utilisation means that the LRMC of network usage is likely to be relatively high. While resisting a precise relationship between utilisation and adjustment to the network element costs, Ernst & Young suggested the following 'step-wise' function:

A. If the utilisation of the transmission element is less than 60%, set the adjusted cost to zero.

B. If the utilisation of the transmission element is between 60% and 80%, set the adjusted cost to 40% of the original annual cost of the element.

C. If the utilisation factor is greater than 80%, set the adjusted cost equal to 75% of the original annual cost of the element.

To Frontier's knowledge, the adjusted CRNP method is in place in South Australia and Tasmania, while the standard CRNP method is used in most other NEM States.

In addition, the extent to which historical network costs can properly be used as a proxy for future network costs depends on whether technology and network element prices remain stable over time. If future costs diverge significantly from historical costs, basing locational charges on the value of historical assets (as under CRNP) will provide a distorted representation of LRMC. In such circumstances, the forward-looking ICRP approach in BETTA could provide a more appropriate solution.

Nevertheless, in both the NEM and BETTA, it should be noted that not all network costs are recovered through load-flow-based charges. Both jurisdictions typically recover at least 50% of network costs through postage-stamped charges, despite neither jurisdiction employing full nodal pricing in their respective energy markets. Further, if a load flow approach were considered for New Zealand, it would make sense to treat HVAC and HVDC assets and costs together – there would seem to be little analytical basis for maintaining the distinction if the basis of allocation was some measure of network use.

Another common attribute and criticism of load flow approaches is their complexity and lack of transparency to market participants.[36] That is, even if prices are derived in a robust and careful manner, most participants will seldom understand precisely how their charges are derived and specifically why they change from year to year. This was apparently one issue regarding the former load flow-based Transport charge that applied in New Zealand until 1999.[37] On the other hand, load flow approaches tend to be mechanistic and avoid the subjectivity of more 'economic' – as opposed to engineering – proxies of LRMC.

Finally, the allocation of costs to connection points through a load flow model does not resolve the issue of pricing structure. On this matter, the same options are available as for other cost allocation methodologies – usage (MWh), peak and/or shoulder injections/withdrawals (MW) or other alternatives such as plant nameplate capacity.

As with the Grant Read tilted postage stamping option, the case for a load flow-based transmission pricing methodology depends largely on the degree of inadequacy of nodal pricing as a locational signalling device. This, in turn, depends largely on the extent to which the outcomes of the transmission planning and investment process reflect economically efficient decisions.

3.5 Treatment of connection costs

Connection costs are traditionally described and discussed by reference to either:

- 'Shared' network costs in respect of augmentations upstream or downstream of the point of connection incurred as a consequence of the connection of a new participant or

- 'Dedicated' connection costs directly incurred in order to connect the participant to the network.

This section discusses alternative treatments of both shared and dedicated network costs arising from the connection of new participants.

3.5.1 'Deep' connection charging option

Most of the high-level options canvassed above focus on the allocation of 'shared' network assets and costs. This makes sense as shared use assets involve the greatest externalities and hence the choice of methodology for allocating their costs presents the most difficult economic efficiency issues.

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36 Ernst & Young referred to the Australian CRNP methodology as a 'black box'. See Ernst & Young, "The cost reflective network pricing algorithm: role and refinements in transmission pricing", p.72 in NECA, *Transmission and Distribution Pricing Review, Final Report, Volume II*, July 1999, available here.

37 Strata Energy Consulting, *DRAFT Report on Transmission Pricing Methodologies – 1988 to 2008*, June 2008, para 20(b), p.9.

In this context, one option for changing existing connection charging arrangements is to introduce a 'true' deep connection charging regime (also known as a 'but for' approach), as in place in the Pennsylvania-New Jersey-Maryland (PJM) market in the United States. Under this approach, generators wishing to participate in PJM's capacity market must pay the cost of restoring PJM's reliability criteria that may have been adversely affected by their connection.[38] This amounts to generators being liable for both the connection assets and shared network augmentations necessary to ensure their capacity is available when required. In exchange, contributing generators receive financial transmission rights (FTRs) to help hedge the nodal pricing signals they face in settlement.

Such a deep connection charging approach could be adapted for New Zealand. For example, new connecting parties could be required to pay for system upgrades required to support their load or generation facility. In exchange, the connecting party could receive some form of financial rights over the additional transfer capability provided by the relevant upgrade(s). This would result in new loads or generators connecting to those assets paying a share of the depreciated costs of those assets. Over time, the upgrade costs could be refunded to the original connecting participant as an offset to its interconnection charges.

However, if such an option were to be pursued in New Zealand, a number of issues would need to be resolved or otherwise addressed.

First, how would one identify downstream or upstream augmentations 'required to connect' a new participant's load or generation? The presence of the Grid Investment Test (GIT) in New Zealand means that shared network augmentations are only undertaken where they satisfy one or other limbs of the GIT, not simply where they are necessary to preserve the pre-existing ability of incumbent generators to be dispatched to a certain level. The need to preserve the ability of incumbents to be dispatched is a concern in PJM due to the existence of capacity markets – presumably such markets can only serve their purpose if capacity will be available to serve demand at peak times. By contrast, in New Zealand, energy-only nodal prices are intended to provide signals for investment in new generation capacity and provision of additional interconnection capacity may not be necessary or efficient (i.e. not pass the GIT on a net benefits basis). However, if downstream augmentations are sought by new generators in New Zealand, they are not prohibited from entering into investment contracts to fund interconnection assets, and it would be consistent with current arrangements for them to receive the loss and constraint rentals from these investments.

38 See Joskow, P.L. (2005). Transmission policy in the United States, *Utilities Policy*, 13(1), pp. 95-115, available here.

Even if augmentation costs can be attributed to a particular new connection, this does not address the situation where the need for shared network augmentation is driven by *incremental* growth in load or generation, rather than by a discrete new connection.

Third, if subsequent connecting parties were required to contribute towards the (depreciated) costs of upgrades paid by the original connecting parties, this could lead to inefficiency. Specifically, charging new generators and loads for network upgrades that have already been undertaken may lead to inefficient locational decisions if it discourages the utilisation of sunk assets. For example, a new generator may be (inappropriately) deterred from locating in a remote area by a large deep connection charge, even if a recent augmentation has created substantial spare network transfer capacity out of that area.

Finally, various issues arise regarding the treatment of spur line assets under such an option. As such assets fall in the grey area between 'dedicated' connection assets and 'shared' network assets, the allocation of their costs would need to be resolved if the current approach were found to be unsatisfactory.

3.5.2 Dedicated connection costs

As noted in section 2.3.2 above, the allocation of dedicated connection costs is relatively straightforward because there are fewer externalities to consider. That said, connection assets (as defined in the existing TPM) do give rise to some difficulties primarily because of the scope for connection assets to be shared by two or more participants, either from the outset of commissioning or over time. Some of these were highlighted by the TPTG (see section 2.1.3 above).

A draft working paper by NERA Economic Consulting for the New Zealand Electricity Industry Working Group (NERA draft working paper) highlights two key issues arising from the delineation of network assets:

- 'Right-sizing' spur lines – if spur lines are classed as connection assets, there is a question as to how to ensure they will be built to a size capable of accommodating future expected connections (either generation or load) rather than simply just being built to accommodate the individual participant seeking the initial connection.
- Cost allocation to subsequent connecting parties – participants will be deterred from seeking connection if subsequent connecting parties can 'free-ride' on their investment by connecting at only incremental cost.

Both of these issues were raised in the Australian Energy Market Commission's (AEMC's) first interim report on climate change impacts on energy markets.[39]

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39 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies, 1st Interim Report*, 23 December 2008, pp.37-39, available here.

The second interim report proposes a new transmission planning and investment regime for addressing these issues.[40]

In relation to the first issue, the NERA draft working paper briefly suggests pushing out the boundaries of the interconnected network by allowing certain new connection assets to be considered as expansions of the interconnected network where they are likely to maximise net market benefits under the GIT. However, we understand that there is a contestable market for connection services in New Zealand. This facilitates negotiation between connecting parties to arrive at the efficient sizing of new spur lines. It is also open to investors to develop larger assets than justified on the basis of present demand in order to capture potential later economies of scale when subsequent plant seek connection. Therefore, in the absence of evidence that this is a significant problem, the current regulatory regime appears satisfactory.

In relation to the allocation of existing connection costs amongst initial and subsequent connecting parties, the existing TPM offers a pro-rated solution. That is, each party is required to pay on the basis of its relative anytime maximum injection (for generators) or withdrawal (for offtake).[41]

3.6 Treatment of transmission alternatives

An issue that often arises in transmission pricing methodology is the treatment of transmission 'alternatives', such as local generation and demand-side management (DSM). Transmission alternatives may even include grid-connected generation in relatively load-rich areas such as the north of the North and South Islands. These options are often considered in the GIT when new transmission projects are being assessed.

To a large extent, the treatment of transmission alternatives ought to be no different from regular grid-connected generation and loads. If nodal pricing signals are deemed to provide adequate locational signals for generators and loads generally, there is no analytical basis for providing additional or separate signals for investments considered to be 'transmission alternatives'. Similarly, if nodal pricing signals are deemed inadequate due to sub-optimal grid planning and investment outcomes, transmission alternatives should face the same signals that other generators and loads face. For example, if the augmented nodal approach is adopted, generators in load-rich areas may need to face negative transmission charges (or rebates) to compensate for the artificially depressed nodal prices they face due to inefficient over-investment in transmission. The case of DSM is

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40 AEMC, *Review of Energy Market Frameworks in light of Climate Change Policies, 2nd Interim Report*, 30 June 2009, pp.14-22, available here.

41 See Strata Energy Consulting, *DRAFT Report on Transmission Pricing Methodologies – 1988 to 2008*, June 2008, pp.9-10.

different, in that the value of DSM can be captured by avoiding positive transmission charges to loads in load-rich areas.

The key exception to this equal treatment approach is local generators (which may be embedded in distribution networks). To the extent such generators reduce the transmission charges payable by lines companies, they ought to be entitled to a share of those benefits. We understand that different lines companies pass on the benefits of lower transmission charges brought about by the output of local generators in different ways and it may be worth clarifying how and why they differ. At the same time, we note that the current arrangements for the HVAC charge – being based on RCPD rather than anytime maximum demand (AMD) – are likely to favour local generators in that the RCPD method provides a more predictable signal.

3.7 Service quality and pricing

As noted in section 2.1.3 above, an issue raised by the TPTG was the current lack of a link between the level or quality of transmission services provided by Transpower and the prices that participants are charged.

Transpower is currently subject to an administrative settlement with the Commerce Commission in respect of its pricing and services. The settlement expires on 30 June 2011 and prior to that time, the Commerce Commission must make a recommendation to the Minister of Commerce that an Order in Council be made declaring the type of price-quality regulation to which Transpower should be made subject.[42]

In 2006, as part of its consultation of the draft benchmark agreement, the Electricity Commission considered alternative approaches to providing for compensation or liability for a breach of the benchmark agreement. The Commission decided at that time to adopt the requirement for Transpower to be liable for the direct costs of losses to directly connected parties. Other options considered included:

- A no liability approach
- A liability for total losses approach
- A liquidated damages approach.[43]

In addition, the consultation paper suggested that several other options could be considered at a later date. These included an unconditional service guarantee (USG) scheme and a voluntary insurance option.[44]

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42 See the Commerce Commission's website here.

43 Electricity Commission, *Benchmark agreement consultation paper and draft benchmark agreement, for the purposes of consultation under section II of part F of the Electricity Governance Rules 2003*, 19 May 2006 (Electricity Commission (2006)), pp.93-95.

Frontier understands that the Commission is interested in considering the option of a USG scheme or a voluntary insurance scheme as part of the review of transmission pricing. A USG scheme would require Transpower to pay compensation for an ex ante determined 'economic loss' incurred by consumers in the event of an unplanned loss of supply arising from the failure of transmission assets. As such, the scheme would encourage Transpower to improve its operational and maintenance decisions in order to minimise the volume of unserved energy. Compensation could be set based on a value of lost load (VoLL) of $20,000/MWh multiplied by the loss of consumption based on a comparison of actual consumption from the grid to historical consumption levels.[45] Transpower would be able to recover a target level of compensation from its customers through regulated charges, and so would have incentives to outperform the target in order to retain the revenue it was not required to pay out in a given year. At this stage, Frontier understands the Commission's expectation that Transpower's exposure under the USG scheme would be capped at $50 million per annum.

A USG scheme would reinforce the current uniform economic reliability standard that applies across New Zealand.

A voluntary insurance scheme is also under consideration. Under a voluntary insurance option, Transpower would make insurance for loss of supply available to all customers (including parties, such as retailers, who are not designated counterparties). The requirement to offer insurance would be specified in the Rules. Parties would choose their level of insurance (in terms of $/MWh of unserved energy) based on estimates of their own VoLL and risk mitigation strategies. Transpower would base the premium on the customer's load factor, the assessed reliability of the relevant grid exit point and the expected level of supply interruption.[46]

44 Electricity Commission (2006), pp.95 and 99-101.

45 See Electricity Commission (2006), pp.100-101.

46 See Electricity Commission (2006), p.101.

4 Filtering criteria

Key concepts

We have developed a number of criteria that could be used for narrowing down the high-level options outlined above for more detailed cost-benefit analysis at a later Stage of the Review. Our proposed criteria are as follows.

Criteria 1: As discussed above, the case for locational transmission pricing signals is largely driven by the extent to which actual transmission network investment exceeds the perfectly efficient level of investment. Therefore, one important filtering criterion is the degree of such network 'overbuilding'. We note that the distortions caused by overbuilding will be exacerbated if, as under the current market design, nodal prices are not set to signal the value of unserved energy to consumers when load is shed.

Criteria 2: Another important criterion is the theoretical precision of the methodology, in terms of accurately compensating for the muting of nodal price signals caused by market design or inefficiently excessive or premature network investment.

Criteria 3: The development of locational hedging instruments will also influence the choice of a transmission pricing regime. Broadly speaking, to the extent that locational hedging instruments serve to offset or further mute nodal price signals, the transmission pricing regime will need to impose more locationally-differentiated charges.

Criteria 4: Network topology is another relevant factor in choosing a transmission pricing methodology. In general, load flow approaches are better suited to meshed networks while simpler approaches could be used for radial networks. However, modifications to CRNP can help increase its suitability for radial networks.

Criteria 5: Implementation difficulty and information requirements are another relevant consideration in implementing a transmission pricing methodology.

Criteria 6: The incentives that a transmission pricing regime provides for particular groups of participants to properly scrutinise network planning decisions should also be taken into account.

Criteria 7: Good regulatory practice is an umbrella criterion that encompasses minimising subjectivity, enabling replicability and promoting transparency and predictability of network tariffs. These features all contribute to the degree of confidence that participants can have in the integrity of the signals that the transmission pricing methodology provides.

Criteria 8: Finally, stakeholder acceptability of a pricing regime is relevant, as approaches that are unacceptable to a large proportion of participants will tend to be unstable and face pressures for revision over time.

Different options have different strengths and weaknesses across these filtering criteria.

This section of the report develops and discusses a proposed set of criteria for filtering the high-level options outlined in the previous section, noting that the actual filtering process to formulate a short list of options will be undertaken in the subsequent Stage 2 of the Commission's Review and the detailed evaluation will take place within Stage 3 of the Review in 2010.

The proposed filtering criteria have been formulated in light of both:

- the findings of the efficient pricing theory report discussed in section 2.1.1 and
- relevant policy and regulatory considerations discussed in section 2.3.

For example, the need for the first proposed criterion (divergence from optimal transmission investment) is based on (1) the findings of the efficient pricing theory report combined with (2) the clear emphasis on economic efficiency in the Electricity Act, Part F Pricing Principles and the Government Policy Statement.

This section also offers some preliminary observations regarding how various high-level options might fare under the different criteria. This should provide a reasonable indication of the broad magnitude of the net benefits that each high-level option could be expected to provide over the existing arrangements. The actual estimation of those net benefits would be undertaken in Stages 2 and 3 of the Review. At that point, it may be necessary to develop supplementary criteria for choosing between the various detailed transmission pricing options. In particular, one criterion that could be adopted is that any change from the existing arrangements should offer material expected net benefits compared to the existing arrangements.

4.1 Criteria 1 – Divergence from optimal transmission investment

As discussed in section 2.1.1 above and in Frontier's efficient pricing theory report, to the extent that the transmission system is augmented inefficiently, nodal prices will not provide appropriate investment signals to prospective generators and loads. In particular, there may be over-investment in the transmission network for a range of reasons, including highly risk-averse network planning decisions, the adoption of overly conservative deterministic reliability standards or the success of strong lobbying efforts by remotely-located generators on the decisions of the network planning body in an environment of imperfect information about future network flows and contingencies. These issues will be exacerbated if, as under the current market design, nodal prices are not set to signal the value of non-supply to consumers when load is shed.

By extension, the more that nodal price differentials are 'muted' by inefficient investment, the stronger the case for a locational transmission pricing methodology to compensate for that muting effect on participant investment decisions. At the extreme, if the transmission network is planned in such a manner that any congestion is immediately 'built out' irrespective of cost, prospective investors will not face any material nodal price differentials at all. Under these circumstances, the 'missing' nodal price signals would need to be provided by the transmission pricing methodology.

Therefore, an extremely important filtering criterion to apply to the high-level options in the context of the nodal New Zealand market is the extent to which the transmission network has been overbuilt relative to a perfectly efficient grid that had been developed always and only as required to maximise net market benefits. This means that to the extent that development of the network has proceeded in spite of the availability of lower-cost non-transmission alternatives, the network will not reflect such a 'perfectly efficient' grid.

4.2 Criteria 2 – Theoretical precision

As noted above, the more that nodal price differentials are 'muted' by inefficient transmission investment, the stronger the case for a locational transmission pricing methodology to compensate for that muting effect on participant investment decisions.

Different locational pricing methodologies offer varying degrees of theoretical precision in terms of properly compensating for muted nodal pricing signals. Whilst theoretical precision is not the only or even most important criterion for a transmission pricing methodology to fulfil, ensuring the methodology sends as close as practicable to 'economically correct' signals is clearly relevant to the choice of methodology.

Based on the framework presented in this report and in the efficient pricing theory report, the most theoretically precise of the high-level options is probably the augmented nodal pricing approach. This is because that option seeks to directly address the divergence between 'ideal' nodal prices and actual prevailing nodal prices. The extent to which other options meet this criterion – in other words, the extent to which they would provide prices that mimic those produced by the augmented nodal approach – will generally depend on prevailing network topology and loading conditions. However, assuming the network is inefficiently overbuilt and nodal price differentials are muted as a result, some broad observations can be made:

- Flat postage stamped approaches such as the status quo and optimal tax options would not be theoretically appropriate.

- Tilted postage stamp approaches are unlikely to be theoretically precise because a participant's distance from the main grid, or its longitude or latitude, do not bear a linear relationship to transmission costs and needs in New Zealand, given the extreme variations in geography and resource locations.

- Load-flow approaches – particularly if they draw on the Optimal Replacement Costs of network elements – may provide a closer proxy for theoretically efficient augmented nodal price signals if they are derived in a manner that adequately reflects the distribution of unutilised capacity across the network. This is because a load-flow approach recognises underlying cost issues associated with geographic features and resource locations.

4.3 Criteria 3 – Locational hedging options

At present, the New Zealand market design does not incorporate a formal mechanism for enabling participants to hedge basis risk. We note that the nature and magnitude of this risk is currently partly limited by the fact that nodal prices do not rise to reflect the value of unserved energy in circumstances where load is shed due to a scarcity of supply.

As part of its Market Development Programme, the Commission is currently considering several locational hedging options, including:

- Locational Rental Allocations (LRA) – an LRA allocates constraint (and possibly loss) rentals to spot market purchasers in proportion to their locational price risk.
- Financial Transmission Rights (FTRs) – an FTR is auctioned to the highest bidder and provides the holder with claims to constraint (and possibly loss) rentals on transmission circuits specified in the FTR.
- A hybrid of LRAs and FTRs.[47]

At this stage, it is understood that the Commission is planning to publish a High Level Options Paper on locational hedging options in the next few months. The key implication of the adoption of a locational hedging option on transmission pricing is the impact of the option on nodal pricing signals, noting that these may already be distorted for other reasons such as over-investment in the grid or the fact that prices are not set equal to the value of unserved energy when load is shed. In this context, a presentation by Grant Read suggests that "LRAs may improve some signals and distort others" (relative to nodal pricing without locational hedging options in place).[48] To the extent nodal pricing signals are

47 See the Commission's website here.

48 See the presentation on the Commission's website here.

improved –in that LRAs (or FTRs) help overcome imperfections in nodal pricing signals caused by lumpiness problems – the implications for transmission pricing could be limited. Having said that, it is difficult to see how locational hedging instruments could compensate for the fact that nodal prices in the New Zealand market are not set to reflect the value of unserved energy when load is shed.

On the other hand, if the chosen locational hedging mechanism tends to offset or otherwise (further) distort nodal pricing signals, it may be necessary to apply a more locationally differentiated transmission pricing methodology to compensate for these effects. Nevertheless, it may be the case that the mechanism has little effect on nodal price signals if it covers only congestion costs (and not losses) and if network congestion is minimal due to inefficient transmission over-building.

In any case, depending on the precise choice of locational hedging option, careful analysis will be required regarding the likely impacts on nodal price differentials. This, in turn, will influence the degree of locational variation required of the transmission pricing methodology.

4.4 Criteria 4 – Network topology

The discussion of the various high-level options in section 2 indicated that network topology may also be a relevant consideration in narrowing the choice of options. In particular, the report by Ernst & Young for Australia's NECA explained that the CRNP methodology was likely to yield a closer proxy for LRMC in a highly meshed network that is fully utilised and where increments of transmission capacity are closely matched to load increases (see section 3.4.2 above).

Conversely, in a more radial (or linear) network, it is likely that a CRNP-type approach may only yield a poor – or even an inverse – approximation of the LRMC of participant investment on the network. In such a system, it may be desirable to employ a 'utilisation-adjusted' CRNP approach as adopted in South Australia (see section 3.4.2 above), in order to minimise perverse pricing impacts. Alternatively, a simpler approach to transmission pricing may be more appropriate.

4.5 Criteria 5 – Information requirements/Implementation difficulty

More informationally-demanding approaches are likely to involve greater implementation difficulty. Load-flow approaches require significant modelling input. However, they have proven practicable in Australian and Great Britain. A postage stamp approach and its variations generally impose much less implementation difficulty than load flow approaches. An augmented nodal approach is likely to require substantial information and effort to develop and implement.

4.6 Criteria 6 – Governance arrangements

One relevant consideration to the selection of a transmission pricing methodology is the incentives it provides to participants with respect to transmission planning decision-making processes. At present, generators do not pay the Interconnection Charge and hence have little interest in contesting the GIT analysis of interconnected grid augmentations. Consumers do have an interest in contesting augmentation planning decisions, but often lack the resources to do so effectively. Therefore, it may be appropriate to place some weight on the allocation of costs in the development of potential transmission pricing methodologies.

4.7 Criteria 7 – Good regulatory practice

This is a broad criterion that incorporates minimising subjectivity, enabling replicability and promoting transparency and predictability. These features all contribute to the degree of confidence that participants can have in the integrity of the signals that the transmission pricing methodology provides.

All the tilted postage stamp approaches involve a degree of subjectivity and arbitrariness. However, they are relatively transparent and predictable.

CRNP also has arbitrary elements as physically derived flows are unlikely to recognise the economic benefits that grid users obtain from participating in an interconnected power system. However, it is replicable, if something of a 'black box'. Once implemented, changes tend to be relatively predictable because participants will understand that if network investment occurs in their (electrical) proximity, they are likely to be required to pay towards the costs of that investment.

The augmented nodal pricing approach is novel and likely to involve a large degree of subjectivity, at least initially. It may also not be replicable or transparent. It may however be reasonably predictable, in the sense that participants can observe or predict areas of likely congestion and thereby gain an understanding of how augmented nodal prices might appear and change over time. Therefore, it may be worthy of further investigation and in Frontier's view, a review of high-level transmission pricing options would be unnecessarily restricted if it was not considered further.

4.8 Criteria 8 – Stakeholder acceptability

Stakeholder acceptability is an important criterion for ensuring that once new arrangements are implemented, pressures for further revision or change will be limited. This is ultimately a matter for consultation. However, as a generalisation, it would be reasonable to expect that more radical proposals – in terms of their divergence from the status quo – would be less likely to gain stakeholder acceptability. In this regard, if their somewhat arbitrary logic is acceptable, the tilted postage stamping approaches would appear to present the least difficulties in moving away from the current national postage stamped charge for the HVAC charge. Variations on CRNP methodology could also be acceptable. We note that any alteration to the HVDC charge would most likely be controversial in light of the historical debates surrounding this charge.

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