Transmission Pricing Advisory Group

Draft note how the regulatory context for Transmission Pricing has changed

Version 1: For discussion with TPAG

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Note: This paper has been prepared for discussion with TPAG. Content should not be interpreted as representing the views or policy of the Electricity Authority or the Transmission Pricing Advisory Group.

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1 Introduction and purpose

1.1.1 At the TPAG meeting of 1 August 2011, TPAG requested a note from the secretariat on:

a) how the context has changed from one where merchant transmission investment was expected or encouraged, to the current regime where investment is centrally planned and approved;

b) the reasons that the investment regime has changed – the shortfalls of the merchant investment regime; and

c) the differences between the two regimes and the implications for transmission pricing.

1.1.2 This note has been prepared to prompt discussion amongst TPAG members.

2 The Changes to the Regulatory Regime for Transmission

2.1.1 Over the last 25 years the electricity sector has been progressively reformed and the regulatory environment has been progressively developed. The following table summarises this progression and outlines some of the implications for transmission pricing.

Timeframe	Transmission Investment
Pre 1987 **Centralised government process**	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a government department.
1988 to 1996 **Corporate model**	Transmission investment was undertaken in conjunction with demand forecasting and generation investment through a centralised process operated by a subsidiary of ECNZ – a state-owned integrated electricity generating and transmission business.
1996 to 2003 **Market-based arrangements**	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The process was no-longer centralised and coordinated with generation investment and there was an expectation that grid users would contract, on a disaggregated basis, with Transpower for the services that they required. Grid investments needed to be underpinned by these contractual arrangements. Closing off contractual negotiations proved very difficult and transmission investment, particularly on the "core grid", largely stalled.
2003 to 2010 **Electricity Commission**	Transmission investment was undertaken by Transpower – an independent state-owned transmission business. The EGRs regulated the transmission investment process and over time the investment approval process, the Grid Reliability Standards (GRS), and the Grid Investment Test (GIT) were developed and incorporated in the Rules. The Electricity Commission was responsible for ensuring that transmission investment was efficient.

Timeframe	Transmission Investment
2011 **Commerce Commission**	Transmission investment is undertaken by Transpower – an independent state-owned transmission business. The investment approval process is now overseen by the Commerce Commission. The GIT (to be replaced by an Input Methodology) remains central to the process.

2.1.2 By 1996 competition in the generation and retailing of electricity had been established, the transmission grid had been separated from generation, and a light-handed regulatory regime was in place. Under these arrangements it was expected that:

a) Any new investment in transmission would be underpinned by contracts negotiated through a series of bilateral and multilateral agreements between Transpower and its customers;

b) These contracts would specify the service obligations and payment obligations;

c) Any new investment in transmission would only proceed if Transpower could secure appropriate contracts to underpin the cost.

2.1.3 These arrangements characterise what is often labelled as a 'merchant' transmission regime.

2.1.4 This is in marked contrast to the current regulatory environment in which:

a) any new investment in the transmission grid (apart from some connection assets) are proposed by Transpower and approved by the Commerce Commission and based on a centrally determined national cost-benefit analysis;

b) transmission contracts and the interconnection rules overseen by the Electricity Authority determine the service obligations (The Commerce Commission regime also has a role in determining quality standards for Transpower);

c) transmission revenues and price levels are determined by the Commerce Commission; and

d) the allocation of transmission cost is determined by a Transmission Pricing Methodology.

3 Shortfalls in the Merchant Transmission Approach

3.1.1 Over the period from 1996 to 2003 the electricity sector grappled with how to invest in, and contract for, transmission services, within a self-regulatory framework. During this period:

a) there were ongoing disputes about how the costs of the HVDC transmission should be allocated;

b) disagreements over the appropriate means of contracting for transmission services dictated that Transpower relied upon posted terms and conditions, rather than agreed contracts; and

c) Transpower was not able to secure contracts to underpin any major investment in the transmission grid.

3.1.2 The result was that grid investment stalled and there was ongoing uncertainty about transmission service obligations and transmission pricing.

3.1.3 In order to address these problems[1] electricity sector participants formed the Electricity Governance Establishment Committee in 2001 to oversee a process designed to implement a more collective multi-lateral approach to self-regulation.

3.1.4 As part of these arrangements a work-stream aimed at resolving the impasse over transmission contracting and investment was pursued through 2001 and 2002. Although some progress was made, a workable multi-lateral arrangement for making investment decisions and contracting for transmission services was not able to be agreed.

3.1.5 In 2003 the Government established the Electricity Commission in part to regulate transmission investment and arrangements for contracting transmission services[2]. In adopting this approach New Zealand was following the lead of most electricity markets around the world, where it is generally accepted that the 'merchant' transmission model will fail to deliver an optimum transmission grid as a result of:

a) difficulties in establishing a collective agreement where the sum of private benefits equates to the national benefit (arising from incentives for free-riding and hold-out); and

b) economies of scale that suggest it is in the national benefit to make large investments in transmission that provide value over a long time-frame.

3.1.6 The orthodox wisdom worldwide has therefore become that a centrally planned approach to transmission investment will lead to lower transaction costs and more optimum transmission investment.

4 Implications for Transmission Pricing

4.1.1 If there is no need for an enhanced locational signal because nodal pricing, the investment test and a deep definition of connection send the appropriate locational signal, under a 'centrally planned and approved' model, transmission pricing should primarily aim to allocate sunk costs in a manner that is the 'least distortionary' by avoiding unintended price signals (and incentives on electricity sector participants) that might lead to operational and investment decisions that are not in the national interest.

4.1.2 For some investment decisions, particularly for connection assets, it is possible to argue that we are still in a merchant world; bilateral contracts are feasible with significant decision rights available to customers, and free-riding and hold-out behaviours are not generally a problem.

4.1.3 In the case of the HVDC link it is less clear. Investments in the link are part of the 'centrally planned and approved' process, and the beneficiaries are not identified and provided with decision rights in respect of the investment. In this regard, investment in the HVDC link is treated in the same manner as investments in the HVAC grid.

4.1.4 On the other hand, it can be argued that, whether through a contractual framework or a regulated transmission pricing methodology, participants are more likely to take an interest in, and provide quality information to support, investment decision-making by Transpower and the Commerce Commission, if they have been identified as beneficiaries and expect to be allocated costs accordingly.

[1] Amongst other problems with the approach to regulation of the electricity sector.

[2] Amongst other matters.

5 Allocation of transmission rentals

5.1.1 The Independent Review makes a case that the market surplus arising from losses and constraints in the grid (often called rentals) should cover the cost of transmission, and a first principles approach to pricing transmission services would first identify whether that is the case. If there is insufficient revenue collected from the market surplus, some augmented nodal pricing arrangements should be considered.

5.1.2 Under a pure ‘merchant’ model it would be expected that a party that is meeting the full costs of particular transmission assets would receive the market surplus (or rentals) associated with the nodal price differences across those assets.

5.1.3 In the design of the current regime, it is intended that the market surplus (or rentals) will be used to fund Financial Transmission Rights (FTRs) that are to be made available to participants to hedge locational price risk. A substantial part of the market surplus to fund FTRs will arise from the price differences across the HVDC link. They will therefore not be available to fund transmission costs in the manner apparently contemplated by the Independent Review.