AUSTRALIAN ENERGY MARKET COMMISSION

REVIEW OF THE
ELECTRICITY TRANSMISSION
REVENUE AND PRICING RULES

CONSULTATION PROGRAM

TRANSMISSION PRICING:
ISSUES PAPER

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Abbreviations

AARR	Aggregate Annual Revenue Requirement
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AER	Australian Energy Regulator
BLMP	Base Load Marginal Price
BSUoS	Balancing Services Use of System
CAISO	California Independent Systems Operator
CAMMESA	Compañía Administradora del Mercado Mayorista Eléctrico S.A.
Code	National Gas Code
Commission	See AEMC
CRNP	Cost Reflective Network Pricing
CRR	Congestion Revenue Right
DSM	Demand Side Management
ENRE	Ente Nacional Regulador de la Electricidad
FERC	Federal Energy Regulatory Commission (USA)
FTR	Firm Transmission Rights
GSP	Grid Supply Point
HVAC	High Voltage Alternating Current
HVDC	High Voltage Direct Current

ICRP	Investment Cost Related Pricing
IRSR	Inter Regional Settlement Residue
ISO	Independent Systems Operator
KPX	Korea Power Exchange
kW	Kilowatt
KWh	Kilowatt hour
LMP	Locational Marginal Price
LRMC	Long Run Marginal Cost
MAR	Maximum Allowed Revenue
MCE	Ministerial Council on Energy
MNSP	Market Network Service Provider
MW	Megawatt
MWh	Megawatt hour
NECA	National Electricity Code Administrator
NEL	National Electricity Law
NEM	National Electricity Market
NEMMCO	National Electricity Market Management Company
NGC	National Grid Company (Britain)
NVE	Norwegian Water Resources and Energy Administration
OATT	Open Access Transmission Tariff (USA)
ORC	Optimised Replacement Cost

PASA	Projected Assessment of System Adequacy
PJM	Pennsylvania – New Jersey - Maryland
Regulated Revenue	The remuneration a TNSP receives under the regulatory arrangements such as revenues a TNSP can earn or maximum prices a TNSP can charge
Rules	National Electricity Rules
SCO	Standing Committee of Officials
SMP	System Marginal Price
SRMC	Short Run Marginal Cost
TCC	Transmission Congestion Contracts
TNSP	Transmission Network Service Provider
TO	Transmission Owner
TRANSENER	Compañía de Transporte de Energía Eléctrica en Alta Tensión S.A.
TNUoS	Transmission Network Use of System
TUoS	Transmission Use of Service

Introduction

The National Electricity Law requires the Australian Energy Market Commission (AEMC) to amend the National Electricity Rules governing the regulation of transmission revenue and prices before 1 July 2006. The AEMC is conducting a review that includes broad consultation, to develop a Rule change proposal and draft Rules.

As the first phase of consultations, the AEMC published a Scoping Paper in July 2005 seeking comments from all stakeholders on what should be considered as part of the Review. In the Scoping Paper the Commission also sought comments on undertaking the Review in two stages, with the first stage (revenue regulation) to be completed by 1 July 2006 and the second stage (pricing) to be completed by 1 January 2007.

This Issues Paper seeks comment regarding the pricing aspects of the Review. It follows the Issues Paper on revenue published in October.

As the first major review since the establishment of the new national regulatory regime in July this year, the Scoping Paper and the two Issues Papers have been framed in an open way to seek substantial and broad ranging feedback from stakeholders.

The Commission has an open mind about the approach to transmission pricing regulation that may be adopted in the revised Rules. This consultation approach is a valuable opportunity for the Commission to listen to the comments and opinions of all stakeholders.

This Issues Paper reflects matters identified in stakeholder submissions on the Scoping Paper and the Commission's preliminary research and analysis on matters of significance.

Key themes raised in submissions include the need for regulatory arrangements that achieve a better alignment between investments in and operation of transmission networks and the interests of market participants and electricity consumers. A second important theme is the desire to provide greater clarity, certainty and consistency in the application of regulation.

The Commission will have particular regard to the substantial experience in transmission pricing regulation and practice since the commencement of the National Electricity Market as well as the interrelationship of pricing matters to transmission revenue regulation.

This Paper raises questions and alternatives in a number of areas to elicit views from stakeholders.

Once the submissions on the Issues Paper have been received and the Commission has conducted its own analysis, the AEMC will issue a detailed Options Paper in April 2006 as the basis for further consultation.

Interested stakeholders are invited to make comment on the issues outlined in this Paper. Submissions should be received by 5 pm on 12 December 2005. Submissions can be sent electronically to submissions@aemc.gov.au or by mail to:

Australian Energy Market Commission
PO Box H166
AUSTRALIA SQUARE NSW 1215

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1 Approach to the Review

1.1 Background

One of the first projects to be undertaken by the AEMC (or Commission) is to review, and as required, amend the Rules for electricity transmission revenue and price regulation.

In July 2005 the Commission released a Scoping Paper that looked at what issues it considered were within the scope of the Review. These issues broadly fell into two categories - those surrounding the Rules governing the setting of a Transmission Network Service Provider's (TNSP) regulated revenue (such as through setting maximum revenues a TNSP can earn or maximum prices a TNSP can charge) and those that surround the regulation of transmission prices. The Commission subsequently released an Issues Paper in October 2005 that covered the revenue requirements of TNSPs. This second Issues Paper identifies and discusses the issues surrounding the regulation of transmission prices.

In preparing this Paper the AEMC has taken into account the comments of stakeholders on its Scoping Paper. The Commission has also had regard to the National Electricity Law (NEL) requirements in coming to a preliminary view on the appropriate coverage of this Review, which will result in the preparation of a Rule change proposal and draft Rules.

This Issues Paper sets out those issues that appear to be within the scope of the Review and highlights a series of questions where the Commission is seeking feedback from stakeholders. This feedback will be an important input to the Commission's consideration of what, if any, changes to the Rules are appropriate.

1.2 Structure of this Issues Paper

This chapter sets out the Commission's approach to the Review. It begins by discussing the Commission's overall approach to considering potential changes to transmission price regulation and, as part of this discussion, identifies the key issues the Review needs to resolve (section 1.3). This leads on to a brief discussion of key themes of the Review (section 1.4). Section 1.5 highlights some matters that the Commission considers are outside the scope of the Review.

After clarifying the Commission's approach to the Review:

- chapter 2 discusses the threshold question of whether regulation of transmission pricing is necessary;
- chapter 3 discusses the objectives and context of the Review;
- chapter 4 describes the existing transmission charges in place under the Rules;
- chapter 5 describes the framework the Commission will use to resolve the key issues in the Review. This includes a discussion of how economic principles can assist in answering the key issues;

- chapter 6 highlights other aspects of the National Electricity Market (NEM) arrangements that are relevant to the role and regulation of transmission pricing;
- on the basis that price regulation is appropriate, chapter 7 raises alternative approaches for allocating and recovering transmission costs from network users. This includes consideration of both the appropriate split between loads and generators and locational methodologies for shared network charging. This chapter also examines the merits of existing requirements for prudent discounts to particular loads and rebates for embedded generators;
- chapter 8 examines the properties of alternative pricing structures, including energy-based, demand- or capacity-based and fixed prices;
- following the discussion in the Revenue Issues Paper, chapter 9 highlights some issues relating to pricing for non-prescribed services; and
- finally, chapter 10 deals with the unresolved question of inter-regional transmission allocation and transfers.

1.3 The Commission's Approach

Before considering arrangements for the regulation of transmission prices, the Commission must first consider whether the regulation of transmission prices is necessary. If there is no requirement for price regulation, or minimal regulation, then all that may be required is for the Commission to make provision for greater transparency of transmission prices.

If there is a compelling case for the regulation of transmission prices, and something more than price monitoring is required, then two key issues need to be resolved:

- who should pay TNSPs to enable them to recover their regulated revenue; and
- how should such prices be structured?

These two issues are discussed briefly below following the discussion on the need for regulation following the discussion on the need for regulation.

1.3.1 Need for Regulation

As noted above, the Commission has the task of developing Rules governing TNSPs' regulated revenue. The rationale for such Rules is that there are substantial economies of scale and scope in the activity of transmission provision. This means that transmission services are usually most efficiently provided by monopoly TNSPs. Rules governing transmission regulated revenue may therefore be required to restrain the ability of TNSPs to set prices above efficient levels.

The existence of such regulation governing of how much money the TNSPs can recover from users, raises the question of whether Rules are also required to define how TNSPs recover their regulated revenue. That is, should there be regulation of who should pay for transmission and what the structure of charges should be or should these decisions be left up to TNSPs (with or without the oversight of the AER) once their total remuneration has been regulated.

In making this decision, it should be recognised that there are some important interactions with the way the Rules govern the total amount of regulated revenue a TNSP can earn. For example, if the Commission develops Rules that implement a price cap form of regulation for some transmission services, transmission prices will need to be prescribed in the Rules to some extent. A price cap has little meaning without clarity over which prices are the subject of the cap.

On the other hand, if the Commission develops Rules implementing a revenue cap approach, the need to regulate pricing methodology is less obvious, particularly if the focus is on achieving efficiencies in the short term. However, even under a revenue cap regime, Rules for transmission pricing may still be required for two reasons.

- First, TNSPs may not have the right incentives to implement transmission prices that promote the NEM objective, which focuses on achieving long term efficiency. For example, a TNSP may set prices to encourage inefficiently high demand for grid services, resulting in unnecessarily high costs; and
- Second, even if TNSPs have incentives to set the 'right' prices, the market may benefit from greater transparency in the formulation of those prices. In this case regulation could focus on ensuring greater transparency rather than control.

This Issues Paper will explore the robustness of the reasons for pricing regulation in the context of addressing both of the key issues for resolution – who should pay and the appropriate pricing structure.

1.3.2 Who Should Pay?

Given a regime for determining TNSPs' regulated revenue, a process may be required to determine who should contribute to the recovery of the regulated revenue and how much they should each contribute. This involves considering:

- what proportion should loads pay as compared to generators;
- whether participants in different locations should pay different amounts; and
- whether different classes of generators or loads in a given location should pay different amounts or prices.

Currently, loads pay the vast majority of transmission charges. A key issue for this Review is whether this should continue to be the case or whether it is appropriate that generators pay a greater share. Further, the Rules currently recover half TNSPs' shared network regulated revenue on a locational basis and the remainder largely on a postage-stamped basis. This Review will consider both whether the share recovered on a locational basis is appropriate as well as the locational methodology itself. Finally, a key issue for the Review is whether transmission charges should be standardised at each location or whether 'discounts' or other forms of price discrimination to particular customers should continue to be permitted.

The question of 'who pays' may have significant implications for participants' investment and operational decisions. This, in turn, will have implications for the future costs of developing and operating the electricity grid and the NEM in general.

1.3.3 How Should Charges be Structured?

Once issues surrounding who pays what amounts are resolved, the next key issue is determining how transmission prices should be structured to recover these amounts. This involves considering whether prices should be based on:

- energy consumption or generation;
- peak demand or generation capacity; or
- a fixed dollar amount.

The form of price structure will have a major influence on the incentives created by the transmission pricing regime. Prices based on the volume of consumption or generation will tend to deter utilisation of the network. Conversely, prices based on peak demand or generation capacity will tend to not deter network utilisation directly, but may deter participants from expanding their operations. Finally, fixed prices may have the least effect on participants' decisions.

The price structure is therefore likely to affect the investment and operational incentives of actual and potential market participants. Again, this will have implications for the future costs of developing and operating the electricity grid and the NEM in general.

1.4 Key Themes of the Review

The Revenue Requirements Issues Paper addressed two key themes for setting transmission regulated revenue. These two themes were:

- aligning the interests of TNSPs with grid users; and
- seeking greater certainty, clarity and consistency of the regulatory arrangements.

These themes focused on rectifying the main problems that participants appear to have with the current approach for determining TNSP regulated revenue.

Transmission pricing has some role in aligning the interests of TNSPs and market participants. While TNSPs are interested in aligning prices with costs, market participants are primarily concerned about how TNSP revenues are allocated between different user classes.

Allowing TNSPs discretion over the way some prices are set can also lead to different pricing arrangements across jurisdictions. This may result in higher costs for national retailers seeking to develop common pricing arrangements.

In terms of certainty and consistency, one significant benefit of the current arrangement is that it results in stable prices over time. Changing the arrangement may involve price shocks and, in turn, affect certainty around the structure and level of prices. This is important in the current phase of the industry investment cycle, where significant amounts of new transmission and generation investment are required to maintain system security and reliability.

On the contrary, setting prices through the cost reflective network pricing (CRNP) process involves numerous assumptions and complex modelling. This reduces the transparency and, hence, clarity of the arrangements.

There are other themes that the Commission considers relevant to transmission pricing:

- The rationale for regulation – as highlighted above, there is a prior question as to the need for transmission price regulation in some or all circumstances;

- The relationship between discretion and transparency – the less prescriptive price regulation is, the more decisions are implicitly left in the hands of the Australian Energy Regulator (AER) and TNSPs. To provide reasonable certainty for all stakeholders, greater discretion should be accompanied by greater obligations to ensure transparency in price setting;

- The need to make trade-offs in developing Rules for transmission pricing – appropriate Rules may need to make trade-offs between:

    - theoretical purity and practicability; and
    - efficiency in the short run (static efficiency) and efficiency in the long run (dynamic efficiency). This tension is most obvious when considering pricing arrangements that encourage utilisation of idle transmission capacity (which is efficient in the short run) and pricing arrangements designed to signal future costs that a transmission customer's present demand may lead to (long run efficiency); and

- The importance of taking into account other aspects of the NEM arrangements – for example, the regional pricing structure and transmission investment arrangements.

These themes arise throughout the course of this Issues Paper.

1.5 Matters Outside the Scope of the Review

There are a number of other elements of the NEM design and regulatory framework that should be taken into account in developing Rules for transmission pricing. For example:

- Regional pricing structure of the NEM;

- The open (non-firm) access transmission regime; and

- Regulatory arrangements for transmission planning and investment (including the Regulatory Test).

These other NEM elements are discussed in detail in chapter 6. At this point it is important to note that this Issues Paper will generally take the existing market and regulatory arrangements as given. The exception to this position is where particular market or regulatory arrangements are currently being reviewed. For example, to the extent that alternative regulatory treatments of TNSPs' regulated asset bases or adoption of *ex ante* compared with *ex post* treatments of capital expenditure give rise to different TNSP incentives, the implications for transmission pricing will be within the scope of this Review.

2 Requirement for Regulation

It was highlighted above that the Commission's starting point for the Review is to ask the question of whether any price regulation is required (as distinct from regulation of TNSP revenues). If there is no compelling reason to regulate transmission revenues, it would be difficult to imagine any reason for regulating the way TNSPs set transmission prices. If there is a compelling case to regulate transmission revenues, this does not necessarily mean that there is also a case to regulate prices. It may be the case that once revenues are regulated, TNSPs have adequate incentives to set prices that encourage efficient use of the network without the imposition of further pricing regulation or with a minimal set of guiding principles. This issue is discussed in more detail below.

2.1 TNSP Incentives

In general, both revenue cap and price cap regulation creates some incentives for TNSPs to set prices in a way that encourages users to make best use of the existing network, at least in the short term. For example, in a regulatory regime where the TNSP has its price, rather than revenue, capped, and does not have to return any revenues earned in excess of what the regulator originally allowed, the TNSP has an incentive to set the structure of its charges in line with the structure of its costs.

If a TNSP's costs are not expected to vary significantly with demand or energy over the length of the regulatory period, a TNSP can be expected to attempt to maximise revenues by maximising utilisation of the network. More specifically, left to choose its own pricing arrangements, a TNSP is likely to charge:

- lower prices to customers whose consumption could decline in the face of higher prices; and

- higher prices to customers whose consumption would not decline in the face of higher prices.

In the longer run this pricing approach could encourage greater consumption, resulting in higher long term costs than otherwise. This may also result in some longer term inefficiencies.

A similar incentive to price to encourage greater utilisation of the grid may also exist where TNSPs face capped revenues in combination with the risk of having underutilised assets written down by a regulator (known as an optimisation risk). However, if a TNSP has its revenue regulated and it does not face any optimisation risk then it may be indifferent to how efficiently the grid is utilised. In these circumstances the TNSP may simply put in place a pricing system that is cheap and easy for it to administer. It is unclear whether this would create any economic inefficiencies or not.

On the other hand, a TNSP may take the view that even if it is revenue regulated and faces no optimisation risk, it might still price in a way to encourage greater utilisation of the network so this creates longer term growth prospects for the business. As identified above this may not be efficient in the long run.

2.2 Broad Regulatory Options

The current price regulation arrangements in the Rules are highly prescriptive, and provide the AER with little discretion (see chapter 4). If it is considered that regulation is required there are alternatives to the highly prescriptive arrangements that currently exist.

One option may be for the Rules to lay out the objectives of the pricing regime but allow TNSPs freedom (perhaps under the supervision of the AER) as to how these objectives are achieved. This would contrast with the current detailed allocation approach in the present Rules.

For example, the Rules could require that transmission charges be based on forward looking long run costs and set out what this should be designed to achieve (eg, certain locational, consumption or production outcomes). The AER could be made responsible for ensuring each TNSP's price structure conformed to the objectives.

If such discretion were conferred on TNSPs, and such responsibilities conferred on the AER, it may be appropriate for the Rules to impose minimum transparency requirements. For example, TNSPs may be required to publish details of their pricing methodology to help users understand current and predict future changes.

It may not even be necessary to set specific pricing objectives in the Rules if the Commission could be confident that TNSPs have the right incentives to develop appropriate charges. This raises the interaction between the pricing Rules and the regime selected to control TNSP revenues.

2.3 Dilution of Transmission Prices through DNSPs

An important consideration in the debate about the need to regulate transmission pricing is the impact of distributors' pricing arrangements. Most electricity consumers are not connected directly to transmission networks. Rather, most consumers are connected to distribution networks. Yet the requirements for Distribution Network Service Providers (DNSPs) to maintain the pricing structure applied by a TNSP to the DNSP's own customers are limited. This suggests that the benefits of regulating transmission prices (such as they might otherwise be) may be significantly less than supposed. This is discussed further in Section 6.2

1. Should transmission prices be regulated and why?
2. If regulation is required what form should this take? For example, should it be less prescriptive and involve greater transparency or be more prescriptive?
3. What role, if any, should the AER have in determining the nature and form of price regulation?

3 Context and Objectives for the Review

The NEL[1] requires the AEMC to initiate and make Rules with respect to the way that transmission revenues and prices are determined by 1 July 2006. The head of power for the AEMC to make transmission pricing Rules is contained in item 16 of Schedule 1 to the NEL. The AEMC must make Rules for or with respect to:

> *"The regulation of prices charged or that may be charged by owners, controllers or operators of transmission systems for the provision by them of services that are the subject of a transmission determination, and the methodology for the determination of those prices."*

In making any Rules, the AEMC must apply the Rule making test and may only make Rules that contribute to the NEM objective. This chapter therefore focuses on describing the requirements of the NEM objective and the Rule making test in the context of both this Review and the wider policy environment.

3.1 The NEM Objective and Rule Making Test

The NEM objective, which guides the AEMC, is set out in the NEL as follows:

> *"The national electricity market objective is to promote efficient investment in, and efficient use of, electricity services for the long term interests of consumers of electricity with respect to price, quality, reliability and security of supply of electricity and the reliability, safety and security of the national electricity system."*

In developing, assessing and determining any proposed Rule changes, including Rule changes arising from this Review, the AEMC is obliged to apply the Rule making test, which states:

> *(1) The AEMC may only make a Rule if it is satisfied that the Rule will or is likely to contribute to the achievement of the national electricity market objective.*
>
> *(2) For the purposes of subsection (1), the AEMC may give weight to any aspect of the national electricity market objective as it considers appropriate in all the circumstances, having regard to any relevant MCE statement of policy principles.*

The Rule making test and the NEM objective are the critical reference points for this Review.

The NEM objective is founded on the concept of economic efficiency, with explicit emphasis on outcomes, ie, the long term interests of consumers. It also emphasises that the interests of consumers encompasses not only the price at which services are provided, but also the quality, reliability, safety and security of the electricity system.

Economic efficiency has three principal dimensions, (referred to as productive, allocative and dynamic efficiency) and, in practice, there is likely to be a trade-off between these. Each dimension is captured by specific references in the NEM objective. For example:

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1 The NEL is contained in the Schedule to the National Electricity (South Australia) Act 1996 as amended by the National Electricity (South Australia) New National Electricity Law Amendment Act 2005.

- efficiency in the use of electricity requires that the system is operated on a 'least cost dispatch' basis (productive efficiency), and that the quality, reliability, security and safety of electricity services are both provided and priced in line with the preferences and valuations of consumers (allocative efficiency);

- dynamic efficiency requires that investment in the electricity supply industry meets consumer demand at lowest cost in the longer run. This means that the Rules ought to encourage the development and adoption of technological change to the extent this is in the long term interest of consumers; and

- where there is a potential trade-off between the long term benefits to consumers, say arising from investment and innovation in network, metering or generation technologies, and the short term benefit of setting prices below their long run economic cost, the benefits of the longer term outcomes should receive due weight.

The arrangements for transmission pricing have a critical role to play in furthering these objectives. First, the primary function of regulation is to address market power and promote competition with respect to the price and quality of supply. Therefore the substance of any Rule change proposal must be designed so it is likely to improve the efficiency and performance of the electricity market as compared with the *status quo* regulatory arrangements.

Second, the Review will need to consider whether the means by which the Rule change proposals seek to achieve the desired outcomes or processes result in regulatory arrangements that are clear, transparent, and predictable. These attributes of good regulation are required to ensure that markets and market participants are well informed, thereby enhancing:

- the efficiency of market related decision making by investors and consumers, whether in relation to transmission directly, to generation or retailing services that depend on transmission, or in relation to transmission alternatives;
- the willingness of investors to commit capital to the NEM, thereby reducing its long term cost; and
- the role of transmission pricing outcomes in signalling investment opportunities to potential investors and signalling to consumers the cost of their energy usage choices.

To the extent the present Rule making process leads to changes in transmission pricing arrangements from the *status quo*, this will naturally affect different network users differently. Some may pay less for transmission than they currently do and others may pay more. Such impacts may occur whether the Rules define new pricing methodologies or whether the Rules leave such matters to the discretion of the AER and TNSPs. It is therefore appropriate to consider whether distributional impacts are relevant to the Commission's task.

The NEM objective refers to the long term interests of consumers. One interpretation of this is that the Rules should be designed to benefit consumers, paying no attention to the distribution of benefits amongst consumers either on a class or a geographical basis.

4. Bearing in mind the NEM objective, should economic efficiency of the Rules be the focus or should it also have regard to the distributional consequences of Rule changes?

5. If the NEM objective should have regard to distributional consequences of Rules changes, how should these be taken into account?

3.2 Policy Context

The Commission's Scoping Paper highlighted[2] the significant amount of analysis that had been undertaken over the past decade or so in the area of transmission pricing, including:

- the national energy market reforms in general, and the expressed intention in the Ministerial Council on Energy's (MCE) Communiqué of 11 December 2003 to move regulation of electricity distribution and covered gas pipelines to the AER, and to bring the Rules governing these services under the auspices of the AEMC;
- the public debate on infrastructure regulation, including the Productivity Commission's recommendations for reform of the Third Party Access Code for Natural Gas Pipelines, and recent consultation[3] on those recommendations by the MCE's Standing Committee of Officials (SCO);
- the MCE Statement on NEM Electricity Transmission;
- the consideration by the MCE[4] of principles for the Regulatory Test for new electricity transmission investment, regional boundary structures and the criteria that should apply for amending boundaries;
- the debate on the merits of moving towards a nodal pricing regime for the energy market and the related questions of the most appropriate transmission pricing and property rights arrangements for a more decentralised NEM;
- reviews of the regional boundary structure[5], and the regulatory and institutional framework for transmission[6];
- the review of transmission pricing undertaken by the National Electricity Code Administrator (NECA) around the time the NEM was established[7]; and

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2 Australian Energy Market Commission, *Review of the Electricity Transmission Revenue and Pricing Rules, Initial Consultation: Scoping Paper*, July 2005, chapter 1

3 Prime Minister's Exports and Infrastructure Taskforce, *The Exports and Infrastructure Taskforce Report*, May 2005, available at http://www.infrastructure.gov.au/

4 MCE, *Statement on NEM Electricity Transmission*, May 2005

5 NECA, *The Scope for Integrating the Energy Market and Network Services*, Vol 1, Draft Report, October 2000. CRA, *NEM – Transmission Regional Boundary Structure*, Consultation Draft, September 2004; CRA, *NEM Regional Boundary Issues: Theoretical Framework Report*, Final Report, September 2004; CRA, *NEM Regional Boundary Issues: Modelling Report*, Final Report, September 2004

6 Firecone, *Regulatory and Institutional Framework for Transmission*, Final Report, November 2004

- the AER's Statement of Principles for the Regulation of Electricity Transmission Revenues and the AER's Compendium of Transmission Guidelines. [8]

The AEMC recognises this work was the product of extensive consultation and debate over an extended period of time, and it will be carefully considered and taken into account in the course of this Review.

3.3 Jurisdictional Requirements

As noted in the Revenue Issues Paper, many of the requirements and standards affecting transmission planning, development and operation are contained in jurisdictional instruments such as legislation, licences, guidelines, orders and rules. Similar jurisdictional requirements may also affect the form and manner of transmission pricing. To the extent they do, this may affect the impact of any changes to the Rules concerning transmission pricing.

3.4 Revenue and Pricing Regulation Interactions

As foreshadowed in the Scoping Paper, the transmission revenue and pricing components of this Review are being conducted in two strands, principally for the purposes of efficient management of an extensive and complex set of issues[9]. However, the Commission recognises that these two areas of transmission regulation have strong linkages. For example, three important areas of interaction are:

- various regulatory arrangements govern TNSP's investment decision making processes (eg, the Regulatory Test) with the aim of ensuring only efficient investments are undertaken. These arrangements may, as a by-product of their primary function, go some way towards fulfilling the role of a regulated transmission pricing regime. In particular, they may provide desirable locational signals to generators and other sources of supply. In doing so, they may reduce the need for prescribing a transmission pricing methodology.

- the impact of potential market developments – for example, the introduction of a firm access regime would alter the nature and quantum of transmission revenue requirements for TNSPs, and the incidence of prices to recover the costs of these additional services; and

- decisions on the appropriate form of price control (revenue or price caps). Different forms of price control may encourage TNSPs to develop different tariff structures or adopt demand management opportunities. The extent to which these incentives may influence these decisions will partly depend on the degree of flexibility TNSPs should have in determining the structure of transmission prices under a given regulatory regime.

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7 NECA, *Transmission and Distribution Pricing Review*, Final Report, July 1999

8 Australian Energy Regulator, *Compendium of Electricity Transmission Regulatory Guidelines*, August 2005

9 Many submissions supported the two stage process, including Energy Networks Association, 19 August 2005, p.2; Electricity Transmission Network Owners' Submission on AEMC Scoping Paper, August 2005, p.1; VENCorp, 19 August 2005, pp.2-3; Hydro Tasmania, 18 August 2005, p.1

These relationships will be dealt with by identifying and dealing with them as they arise in the course of the Review.

4 Current Transmission Pricing Regime

This chapter describes the existing arrangements for the determination of transmission prices in the Rules. The aim of this chapter is to provide a background for the discussion of alternative pricing arrangements in subsequent chapters.

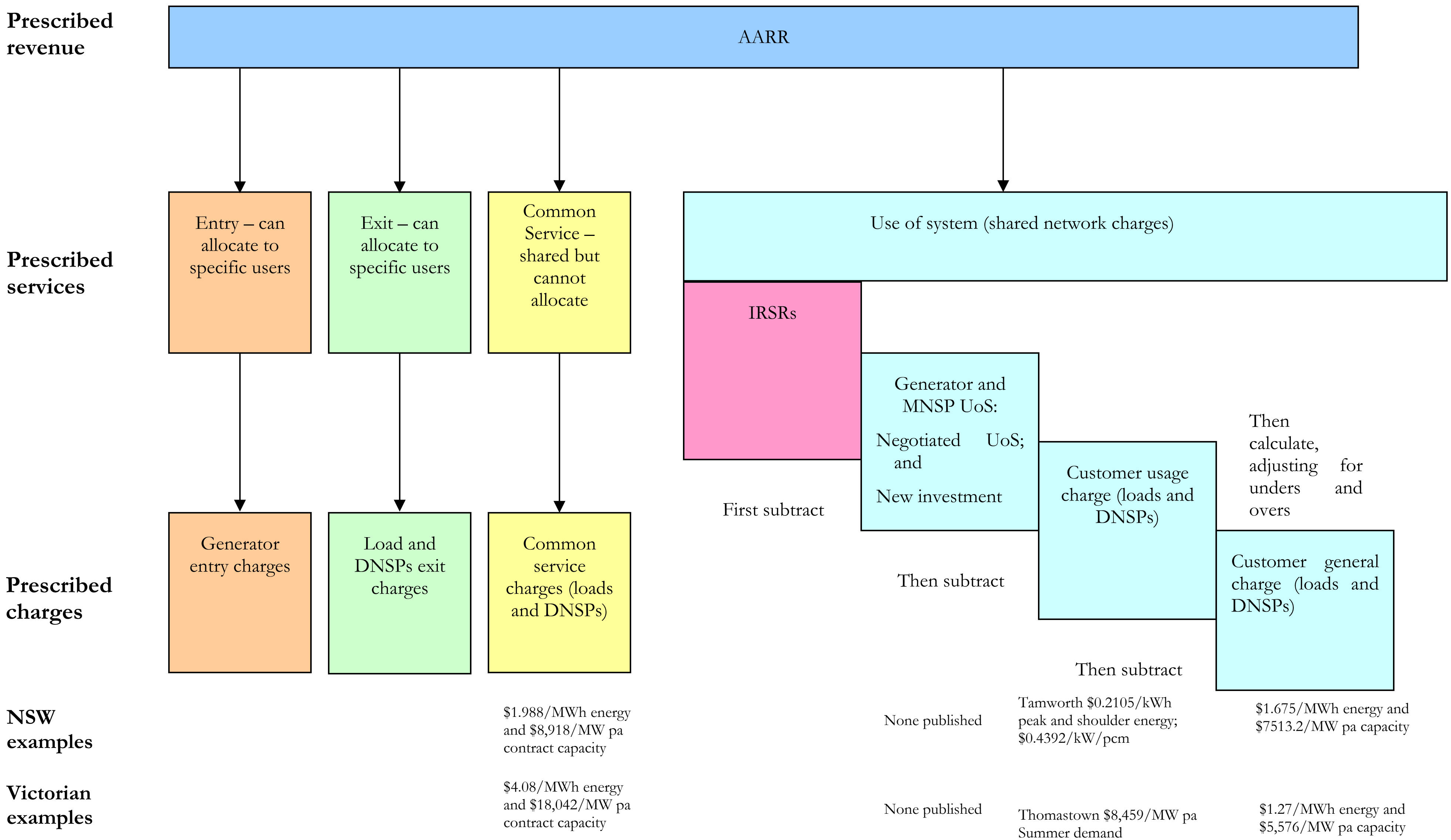
The current pricing arrangements represent a particular approach to regulating transmission prices. It involves a highly prescriptive approach for allocating a TNSP's regulated revenue to particular transmission assets and then to particular users on a partly locational basis. In general, the costs of assets connecting the user to the network are recovered from the relevant connected network user, while remaining asset costs are largely recovered from directly connected loads and DNSPs. In effect this means the majority of transmission costs are borne by consumers.

The final step under the current pricing arrangements is to convert the costs allocated to particular customers into prices. These prices may be based on energy consumption or demand or they may be fixed, but this is one of the decisions that is left to the TNSPs.

The diagram on the next page illustrates how prices are derived under the current arrangements. Following a brief outline of the types of charges (Section 4.2), this chapter goes on to explain the process for deriving transmission prices from the aggregate annual revenue requirement (AARR) and then discusses more specific issues relating to the individual charges currently set out in the Rules:

- Connection charges (section 4.2.1);
- Common service charge (section 4.2.2);
- Shared use of system charges (section 4.2.3); and
- Prudent discounts and Transmission Use of Service (TUoS) rebates (section 4.3).

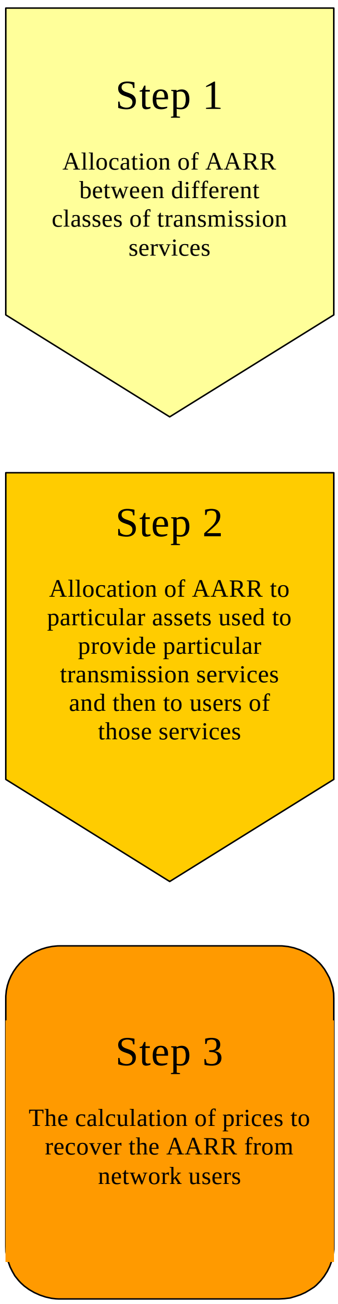
Having reviewed current pricing arrangements, the remainder of this Issues Paper will address how TNSP regulated revenues should be allocated amongst users and transmission prices structured.


Prescribed revenue
AARR
Prescribed services
Entry – can allocate to specific users
Exit – can allocate to specific users
Common Service – shared but cannot allocate
Use of system (shared network charges)
IRSRs
Generator and MNSP UoS:
Negotiated UoS; and
New investment
Customer usage charge (loads and DNSPs)
Then calculate, adjusting for unders and overs
Customer general charge (loads and DNSPs)
First subtract
Then subtract
Then subtract
Prescribed charges
Generator entry charges
Load and DNSPs exit charges
Common service charges (loads and DNSPs)
NSW examples
$1.988/MWh energy and $8,918/MW pa contract capacity
None published
Tamworth $0.2105/kWh peak and shoulder energy; $0.4392/kW/pcm
$1.675/MWh energy and $7513.2/MW pa capacity
Victorian examples
$4.08/MWh energy and $18,042/MW pa contract capacity
None published
Thomastown $8,459/MW pa Summer demand
$1.27/MWh energy and $5,576/MW pa capacity

4.1 Process for Determining Transmission Prices

Part C of Chapter 6 of the current Rules sets out the process by which a TNSP's AARR is recovered through transmission prices. This process and the application of CRNP within it are mechanical asset-based approaches for allocating costs between users and is summarised in Figure 1.

Figure 1: Process for allocating the AARR



Step 1 involves the allocation of:

- network elements (assets) to particular service categories based on the delineation in schedule 6.2; and
- operating and maintenance costs to transmission services.

Step 2 is based on the allocation of:

- the AARR to particular assets based on the relative optimised replacement cost (ORC) of the asset compared with the ORC of all the TNSP's assets; and
- the cost of services to transmission connection points using various allocation methodologies, such as direct allocation to connected parties for entry and exit services and CRNP (or modified CRNP, where approved by the AER) for the customer usage charge.

Step 3 involves the calculation of prices to users of particular transmission services at:

- each connection point (for entry, exit and customer usage charge); or
- all transmission customer connection points (for customer general and common service charges).

4.2 Types of Charges

Currently, there are three types of transmission charges in the NEM – connection, overhead and system usage charges. This categorisation aims to allocate costs to users where there is a reasonable basis for doing so and smeared across all users where they can't. These charges are summarised in Table 1and discussed in more detail below.[10]

Type of charge	Name of charge	Revenues covered	Who pays
Connection charge	Entry charge	Connection of generator to grid	Generators
	Exit charge	Connection of large customers and distributors to grid	Customers – large directly connected customers and DNSPs on behalf of small customers
Overhead charge	Common service charge	Essentially revenues attributable to overhead assets that cannot be allocated to a particular location – eg control systems, communication systems, head office, etc	Customers – large directly connected customers and DNSPs on behalf of small customers
Usage charge	Generator use of system charge	Charges for services that a generator negotiates directly with TNSP, For example for over standard services. Not used to Commission's knowledge	Generators and MNSPs
	Customer usage charge	Covers half the TNSPs revenues attributable to the shared network (ie, assets that are not connection assets or other assets paid for by generators/ MNSPs). Charge applied on a locational basis using Cost Reflective Network Pricing methodology	Customers – large directly connected customers and DNSPs on behalf of small customers
	Customer general charge	Covers the remainder of TNSPs' revenues attributable to the shared network	Customers – large directly connected customers and DNSPs on behalf of small customers

Table 1: Current TUoS charges

10 Clause 6.5, National Electricity Rules

4.2.1 Connection Charges

The term connection charges refers to both entry and exit charges for services provided at generator and load connection points, respectively.

Clause 6.4.2 of the Rules provides that where there is no contract dealing with the allocation of the costs of connection services, the allocation is to be determined as set out in that clause. Therefore, the Rules only govern the allocation of connection costs where it has not already been agreed by the parties as part of the negotiations involved in reaching their connection agreements.

The Commission understands that since the start of the NEM, the allocation of most connection costs have been negotiated under connection agreements, as intended by Chapter 5 of the Rules. Therefore, the provisions for entry and exit charges in the Rules relate mostly to pre-NEM connections, which include DNSP connections.

4.2.1.1 Entry charges

Schedule 6.2 to the Rules sets out categories of transmission system costs. Entry assets are those that are dedicated to providing connection to a single generator or group of generators connected at a single point in the transmission network. They are intended to be assets that require no complex analysis to determine who benefits from them. This reflects a 'shallow connection' approach, which is intended to avoid the difficulties of a 'deep connection' approach, in which assets may change from connection assets to shared network assets when new parties connect to them.

Entry assets generally include transmission switchgear and associated plant used for connection of the generator's transformers, as well as some substation assets. Meters on feeders and substation land are also treated as connection assets. Radial transmission lines from the generator to the TNSP's assets may also be connection assets.

Entry charges are fixed annual amounts charged to the relevant connection point.

4.2.1.2 Exit charges

Exit charges include the costs of all switchgear at the subtransmission voltage level, transformers that supply the subtransmission voltage level and associated switchgear at both the transmission and subtransmission level. Exit charges also include some substation establishment and building costs, including land, bus ties at the transmission voltage level and reactive plant installed for power factor correction. Meters on feeders are also included as connection assets.

As with entry charges, exit charges are fixed annual amounts charged to the relevant connection point.

6. Is the allocation of network costs between the connection and shared network categories in the Rules broadly appropriate? If not, how could it be improved?

4.2.2 Common Service Charge

Common service charges intend to recover a range of costs that provide benefits to all network users and cannot be reasonably allocated to a particular customer in particular location. They include:

- common services – such as communications networks, control systems, switching centres and land and buildings not associated with substation or line easements (eg, head office buildings); and

- non-asset related services – such as network switching and operations, administration and management, network planning and development and general overheads.

In most cases, common services charges are based on a price per unit of historical consumption two years prior to the financial year in question. However, some customers may be charged on the basis of a capacity price, where a maximum demand was provided for in the customer's connection arrangements and where this approach produces a lower charge for the customer.[11]

7. Should a common service charge be maintained or should these costs be incorporated into another charge? If not, how should common service costs be allocated or incorporated into other charges?

4.2.3 Usage Charges

4.2.3.1 Shared transmission use of system charges

Assets that do not provide connection services or common services are shared network assets. These assets include all elements of the transmission network that provide conveyance of electricity on a locational basis, such as transmission lines, switchgear on lines, auto-transformers and so on. However, in the case of some assets, whether they should be allocated to common service or shared network services does not appear to be clear. For example schedule 6.2 of the Rules seems to allocate some reactive control plant and control systems to both categories.

The AARR attributed to the shared network is recovered through several use of system charges, as described below.

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11 Clause 6.5.6, National Electricity Rules

4.2.3.2 Generator and MNSP use of system charges

The Rules provide for generator and Market Network Service Provider (MNSP) use of system charges. As noted above, this includes use of system charges negotiated between TNSPs and generators and MNSPs for contributions to new transmission and distribution investments. Because they are subject to negotiation between these parties they are not prescribed. As far as the Commission is aware, no such charges are in operation in the NEM, nor have generators voluntarily contributed to shared network investments (known as funded augmentations in the Rules[12]). This may be because generators believe there is little point in paying for network augmentation without property rights to the capacity created. The situation regarding MNSP contributions to shared network assets may be different.[13]

8. Should generator and MNSP use of system charges remain a matter for negotiation with the TNSP or should they be prescribed in the Rules?

4.2.3.3 Customer usage charge

Half of use of system network costs must be allocated to connection points by the TNSP on a locational basis using the CRNP methodology, or the modified CRNP methodology if the AER approves.[14] The Commission understands that the origin of the 50% proportion may have emerged to manage any initial price shocks when these arrangements were introduced. In any case, once costs have been allocated, the structure of customer usage charges is determined by the TNSP. The TNSP may choose any combination of demand-based, energy-based or fixed charges. However, the TNSP must take into account the conditions of the network that influence the need for network investment.[15]

The Rules limit changes to the customer usage price to 2% per annum relative to the average usage price for the region.[16] Submissions from NRG Flinders, The Group and EnergyAustralia suggested reconsidering this limit.[17]

Cost Reflective Network Pricing (CRNP)

One of the features of electricity networks is that electricity flows within a network follow complex paths due to Kirchhoff's Laws. This means that changes to transmission lines or other assets in one part of the network can exert profound influences on the capability of other parts of the network. Such 'network spillovers' make precise analysis of how

12 Clause 5.6.6B, National Electricity Rules

13 According to the Murraylink application for conversion to a prescribed service, Murraylink funded a number of developments to other networks. For example, a new substation at Monash and a new 132 kV line into Monash (pp.13-14).

14 Clause 6.3.4B(c), National Electricity Rules

15 Clause 6.5.4(b), National Electricity Rules

16 Clause 6.5.5, National Electricity Rules

17 NRG Flinders submission, p2. The Group submission, p.8; EnergyAustralia submission, p.13

consumption or production decisions at a particular transmission connection point affect network flows and the need for transmission investment highly problematic.

The CRNP methodology is a response to these difficulties. It is essentially an electrical engineering tool for attributing network usage to particular loads in order to provide the basis for longer term locational pricing signals to users.

The CRNP methodology in the Rules allocates a proportion of the costs of each shared network element to each load connection point based on the load's deemed proportionate use of each network asset over a range of operating conditions. A full summary of the CRNP methodology is contained in Schedule 6.4 of the Rules. However, in brief, CRNP involves the following steps:

1. Assign a cost to each network element, equal to 50% of that transmission element's maximum allowable annual revenue (MAR). A transmission element's MAR is a fraction of the total MAR for all such assets (pro-rated on the basis of optimised replacement cost (ORC)).

2. Run the CRNP allocation algorithm, using a set of recent historical load and generation patterns (representing peak transmission use), with the existing network configuration. Inter-regional imports and exports should be treated as notional generators and loads respectively.

3. Each run (for each loading pattern in the set) determines a flow component on each transmission element which is imposed by the demand at each load point.

4. Determine the maximum flow components imposed by demand at each connection point on each transmission element, and allocate the assigned 'cost' of each element on a pro-rata basis to those connection points which impose a flow component on the transmission element in the direction of the standing flow.

5. For every node, calculate the total allocated cost by adding together the costs for each individual transmission element which has been allocated to the particular connection point.

6. Calculate a price consistent with the TNSP's choice of pricing mechanism. For example, if charges are to apply to system coincident peaks, the price should be the ratio of the node's allocated cost divided by the nodes' expected system coincident peak. Alternatively, if charges are to be based on annual energy, or anytime peak, use the node's expected annual energy, or anytime peak, as the denominator.[18]

The properties of CRNP, including key merits and limitations, will be discussed in chapter 8. However, one feature that led to the development of the modified CRNP methodology is that CRNP allocates relatively high costs to connection points even where there is plentiful spare capacity on the network elements deemed to serve that load. This is because CRNP

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[18] NECA, *Transmission and Distribution Pricing Review*, Final Report, Volume II, July 1999, pp. 58-59

allocates the costs of existing network elements rather than forward-looking investment costs. If the network has been augmented in a certain area, the costs of using that capacity may be high even though spare capacity is also high. In other words, CRNP may not provide a good basis for developing prices to reflect the Long Run Marginal Cost (LRMC) of using the network.

Modified CRNP

The modified CRNP methodology was developed to overcome the key weakness in the CRNP methodology highlighted above. ElectraNet and Transend presently utilise the modified CRNP approach for their customer usage charges.[19]

Modified CRNP attempts overcome these weaknesses by adjusting the allocation of network costs on the basis of utilisation. Utilisation is to be based on the maximum flow allowed on elements within the normal operating constraints of the network. Therefore, modified CRNP should yield prices that are closer to the true LRMC of transmission at the relevant connection point. At the same time, as noted in the NRG Flinders submission, modified CRNP may still inefficiently (in the short run) deter utilisation of the existing network.[20] This highlights one of the key themes for this Review – the need to make trade-offs between the incentives for network usage in the short run and the long run.

The Rules allow for TNSPs to implement a modified CRNP methodology if it is approved by the AER. However, the Rules do not currently set out the basis on which the AER ought to accept or reject the application of modified CRNP. Nor do the Rules govern precisely how modified CRNP should be applied. It is also worth noting that it is unclear whether the request for the application of modified CRNP can be initiated by grid users as well as the TNSP or AER.

9. If a modified CRNP usage charge is to remain an option:

- should the Rules prescribe the criteria for the AER to accept implementation of modified CRNP?; and
- should any network customer (rather than just the TNSP) be able to request that the modified CRNP methodology be implemented?

4.2.3.4 Customer general charge

The AARR attributable to the shared network that is not recovered by generator use of system charges or customer usage charges is recovered, after subtracting for the expected inter regional settlement residue (IRSR) auction proceeds, by the customer TUoS general charge. The general charge is also adjusted for under or over-recovery of the AARR in previous financial years. As noted above, the general charge is recovered through a postage-

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19 ElectraNet, *Transmission Pricing Methodology*, 15 May 2003, p.6; Transend, *Transmission Pricing Policy*, 12 July 2004, pp.6-7

20 NRG Flinders submission, pp.1-2

stamped price (ie, identical throughout the relevant region(s)) based on consumption at the load connection point over the same period in the financial year ending 12 months previously. For example, the 2005- 06 general charge is based on consumption during the same period in 2003-04. This means that although in the relevant year, the size of the general charge is unrelated to present consumption, in the longer term, it may operate as a tax on network usage. This may deter utilisation of the network, which may harm efficiency, at least in the short run.

10. How well do the CRNP and modified CRNP methodologies accord with efficient pricing principles? Could simpler approaches be applied to produce similar outcomes?

11. If the CRNP and/or modified CRNP methodologies were to be retained are the descriptions of the methodologies in the Rules sufficiently detailed and clear? If not, how could they be clarified?

4.3 Treatment of TUoS Discounts and Rebates

There are two other features of the current transmission pricing arrangement that have been developed since the commencement of the NEM to overcome some of the potential inefficiencies in the arrangements.

The first is the opportunity for large directly connected loads to negotiate discounts where they can show that they have genuine option for by-passing the grid. For the most part these opportunities arise because of the means of recovering fixed and common costs through uniform/averaged general and common services charges.

The second feature is the opportunity for generators to capture some of the benefits they might confer on the DNSP (in terms of lower transmission charges) because of locating in the DNSP's network. These features are discussed in more detail below.

4.3.1 TUoS Discounts

Clause 6.5.8 of the current Rules allows TNSPs to agree to lower transmission prices with a particular user. Where TNSPs agree to reduce the general or common service charge, they may recover the reduction from other loads, so long as the agreement complies with the AER's *Guidelines for the Negotiation of Discounted Transmission Charges*.[21] These guidelines provide a number of avenues through which price discounts can be justified.

Fundamentally, the TNSP needs to show that the discount is necessary (and no larger than necessary) to avoid inefficient by-pass of the network. However, the guidelines provide for 'safe harbour' provisions under which 70% of the cost of a discount can be recovered by the TNSP from other loads without meeting these requirements. The discount provisions have

[21] 3 May 2002

typically been employed where new large industrial loads (or generators on their behalf) are seeking connection.

12. Is it appropriate to provide scope for TUoS discounting in the Rules?

13. If so, could the existing arrangements be refined and how?

4.3.2 TUoS Rebates

Clauses 5.5(i) and (h) of the Rules require DNSPs to rebate 'avoided' transmission charges to embedded generators. If an embedded generator locates in a particular distribution network, this may reduce the need for the TNSP to deliver power to that DNSP. This could have two consequences:

- the DNSP's transmission charges are likely to fall; and

- it may contribute to the avoidance or postponement of a transmission augmentation to serve that DNSP's load.

The existing Rules provisions are designed to ensure embedded generators get the benefit of the reduced transmission charges incurred by the DNSP as a result of the generator's operation. They provide that the DNSP must rebate to the embedded generator the difference between:

- the customer usage charge the DNSP would have paid but for the operation of the embedded generator; and

- the customer usage charge the DNSP actually paid.

Without such provisions, such rebates would presumably be the subject of connection agreement negotiations between the parties.

While these arrangements relate to the relationship between DNSPs and embedded generators, they are also relevant to transmission pricing. This is because avoided transmission rebates were intended as a substitute for generator locational network charges.[22] If such charges existed, TUoS rebates for embedded generators would not have been implemented. In this context, it is worth reiterating that the rebate only relates to the avoided customer usage charge. This is the charge that is presently allocated on a CRNP or modified CRNP basis. In other words, it is the charge that is intended to provide a signal as to the LRMC of using the network at that location. It follows that to the extent embedded generators help avoid or delay transmission augmentation, they receive a rebate based on the long run marginal value of their contribution.

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22 ACCC, *Network pricing and market network service providers*, 21 September 2001, pp.121-122

14. Is it appropriate to prescribe arrangements for TUoS rebates in the Rules? If so, could the existing arrangements be refined and how?

15. Do the current pricing arrangements appropriately cover alternatives which contribute to the avoidance or postponement of transmission augmentation?

16. Should TUoS rebates also apply to generators connected to the transmission network, DSM or other non-electricity options? Does this depend on whether generators generally pay shared transmission costs?

5 Efficiency and Transmission Pricing – Key Concepts

Chapter 1 of this Issues Paper highlighted the key issues for resolution:

- to what extent is regulation of transmission pricing necessary, and if it is:
    - who should pay for transmission services; and
    - how should prices be structured.

Chapter 3 discussed the need for the transmission pricing Rules to meet the requirements of the NEM objective and the Rule making test. The potential ways in which transmission pricing Rules could satisfy these requirements are:

- by promoting economic efficiency; and
- by addressing distributional and price shock implications.

As noted in chapters 1 and 2, there is an initial question of whether there is a need to regulate at all. This chapter explores some of the economic considerations that may appropriately influence the regulation of transmission pricing. This helps provide a framework for addressing the 'who pays' and 'pricing structures' questions, in a manner consistent with maximising efficiency (chapters 7 and 8, respectively).

The first step in developing this framework is to understand the characteristics of transmission in the NEM and how this relates to the efficiency concepts that underpin the NEM objective and efficient pricing more generally.

5.1 Characteristics and Role of Transmission in the NEM

5.1.1 Characteristics of Transmission

Transmission is a service that is substantially provided by large quantities of physical assets with long lives and that have no practical alternative use once they have been constructed.

Electricity flows on transmission networks are also governed by complicated physical laws. For example, Kirchhoff's Laws state that electricity follows the path of least resistance. This means that electricity flows across a network may not follow the shortest path. Instead, electricity may move across multiple parallel paths. These laws make it difficult for users to predict exactly where their power goes to or comes from. This complicates the link between network users' decisions and network flows and costs. These features make it difficult and expensive to define property rights for transmission services. This, in turn, may frustrate the operation of an efficient market for transmission services.

5.1.2 Role of Transmission Services

Transmission performs a number of roles in the NEM. First, the grid enables the wholesale market to exist by enabling buyers and sellers of electricity in different locations to trade with each other. This means that the grid facilitates choice of supplier, which is fundamental to the operation of a competitive market.

At the same time transmission enables excess generation capacity in some regions to be utilised in other regions that need more supply. For both of these purposes, transmission can be seen as a complement to (remote) generation. That is, transmission facilitates the flow of power generated in one location to another location where it is consumed.

Transmission is also increasingly being seen as a substitute to local sources of generation and other activities such as demand side management (DSM) and other energy sources. This means that transmission can avoid the need for, or can itself be avoided by, the development of local generation, DSM and non-electricity options. Therefore, transmission regulation and pricing should ensure transmission does not 'crowd out' alternatives. The Commission considers it important for transmission regulatory arrangements to be structured in a way that ensures that there is an appropriate opportunity for alternatives.

The role of transmission as both a complement and a substitute to other activities lies behind many of the difficulties associated with regulating transmission generally and in setting transmission prices.

5.2 Efficiency of Marginal Cost Pricing

In order to set transmission prices to encourage consumers and producers of electricity and potential investors in both to behave efficiently, it is essential to understand the role of prices in the operation of competitive markets.

At the simplest level, efficiency is concerned with allocating limited resources in a way to best satisfy unlimited wants. Since resources are limited, allocating an input to one use necessarily means it is not available for an alternative use. For example, if gas is used as fuel to generate electricity, it cannot be used to provide domestic gas heating services. Economic efficiency requires that all resources are used in such a way that the value of their use is no less than the value of any alternative use. The value of a good's next best alternative use is known as its opportunity cost or marginal cost. So, for example, the opportunity cost of using gas to generate electricity may be the value of using gas to provide domestic gas heating.

Consumption and production decisions in a particular market will be consistent with efficiency where the price of a good or service equals its marginal cost. If at a particular output level, price exceeds marginal cost,[23] society could be better off by the provision of an additional unit of the good or service.

Conversely, if marginal cost exceeded price, it would imply that the last unit of the good or service provided did not confer sufficient benefits to offset the costs of providing that unit. Therefore, efficient use of transmission networks requires that generators, loads and potential investors in these projects correctly make decisions based on the marginal cost their use (or intended use) imposes on the network. If the price is below this level, grid users will place too great a demand on the grid that will divert resources used to provide these grid services from providing a more valuable service elsewhere in the economy. Conversely, if transmission prices are too high, consumers will not use enough electricity and resources will be diverted to another, lower valued uses.

This is a key principle – prices that are set in a way that encourages inefficient consumption decisions encourages inefficient production decisions. This, in turn, causes waste of society's limited resources.

This raises the question of the appropriate basis for defining the marginal cost for transmission and how these costs can be used to determine efficient prices.

Given the large proportion of transmission costs that relate to physical infrastructure, the marginal cost of using transmission in the short term (when the physical network cannot change) is usually much smaller than the marginal cost of using transmission in the long term (when the physical network can change). The short and long run marginal costs of transmission are discussed in more detail below.

5.2.1 Short Run Marginal Costs of Transmission

In the short run, where the level of physical investment in the transmission network is fixed, the cost of providing an additional unit of transmission services is largely derived from:

- the cost of transmission losses that occur when electricity is conveyed through transmission lines (the cost of losses); and

- the scarcity value of transmission – the difference between the price of electricity in locations connected by a transmission line when the line is constrained (the costs of constraints).[24]

The cost of the physical network is not relevant to the determination of short run marginal cost (SRMC) because it is taken to be fixed regardless of the decisions of network users.

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23 Assuming that no significant benefits or costs that accrue to third parties remain unaccounted for (known as 'spillovers').

24 Transmission constraints occur when the technical limits of lines are reached. These limits can change over time depending upon on wide range of factors including climatic conditions and power flows in related parts of the grid. At the point a transmission constraint is reached, the only way the system can meet all demand is by operating a higher cost generator located on the importing side of the constrained line, or, if there is no plant available, load will have to be shed from the system.

Further, such assets, once developed, have no alternative use. The expenditure on such assets is referred to as ‘sunk’.

Therefore, the SRMC of transmission is largely made up of the cost of constraints and losses. This suggests that to promote efficiency in the short run, the price of using the transmission network should equal the cost of constraints and losses.

5.2.2 Limitations of SRMC Pricing

A transmission pricing regime based solely on the signalling and recovery of the SRMC of transmission may not be sustainable or efficient in the longer run.

First, a pricing regime based on SRMC may not enable TNSPs to fully recover physical infrastructure costs. This is because the costs of transmission losses and constraints are usually small in proportion to the total costs of building the grid. TNSPs generally develop transmission networks according to reliability criteria in the Rules. These standards lead to fewer constraints and tend to have, as a by-product, the effect of reducing losses.

Second, a pricing regime designed to promote efficient production and consumption decisions in the short run may not promote efficient locational and investment decisions in the long run. Both points are explored further below.

5.2.3 Full Cost Recovery

If TNSPs cannot recover the costs of providing transmission services through a SRMC pricing arrangement, they will cease investing in the grid. This will not be in the long term interests of consumers.

One alterative to relying solely on SRMC pricing would be to allow the TNSPs to recover the share of their costs not recovered by SRMC through another, separate payment not dependent on network use. Combined, this pricing structure is known as a two part tariff.

The challenge is to set the second part of the tariff in a way that it does not harm economic efficiency. Recall that prices should reflect marginal cost so that users make optimal use of the network. If the additional charge to recover outstanding costs discourages the use of the existing grid, this could lead to economic inefficiency – at least in the short term.

One method for determining a least distortionary fixed charge is by applying what is commonly referred to as a Ramsey price. Simply, this approach seeks to allocate proportionately more of the fixed transmission costs to customers who are willing to pay a higher price for the services they currently receive. While this principle is simple to explain, it is very hard to implement. This is because it is very difficult to determine users’ willingness to pay. Customers have no incentive to reveal this information lest they be charged more for the services they currently receive.

5.2.4 Long Run Marginal Costs and Efficient Pricing

Policy makers may be concerned that prices designed to signal the SRMC of using the network and recover remaining costs on a least-distortionary basis provide inadequate signals to actual and potential network users of the future cost implications of network use. An alternative is to charge users on the basis of the LRMC of using the grid. EnergyAustralia's submission supported consideration of LRMC as a basis for transmission pricing for this reason.[25]

Such a methodology considers the effect of network usage on all costs, including physical infrastructure. The rationale for prices based on LRMC is that it signals the full costs of network use that would be incurred in the long run. This is intended to provide efficient signals for participants' longer term decisions.

Importantly, setting prices in order to positively influence future decisions is the opposite of setting prices to minimise their impact on future decisions. This highlights the need for transmission pricing arrangements to consider trade-offs between short run and long run efficiency.

- On the one hand, transmission prices should be structured in such a way that they do not deter the utilisation of network assets that are already in existence and have no alternative use. This is often referred to as static efficiency because it takes the existing (sunk) network as a given and avoids consideration of future investment.

- On the other hand, setting prices to maximise utilisation of the existing network may not provide actual and potential network users with appropriate signals about the implications of their locational, consumption and production decisions for the need for future network investment. Prices that do provide appropriate long run signals promote dynamic efficiency.

An important consideration in this context is the importance of transmission pricing to different types of participant decisions and the timeframe of those decisions. For example, transmission prices may be of varying importance to participants when they make:

- (long term) locational investment decisions; and

- (short term) production and consumption decisions.

If transmission prices are relevant to investment decisions but not operational decisions, it may be appropriate for prices to favour towards long run efficiency considerations. On the other hand, if transmission prices are relevant to consumption and production decisions but not investment decisions, it may be more appropriate to orientate prices towards maximising efficiency in the short run.

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25 EnergyAustralia submission, p.11

17. Should transmission pricing arrangements principally seek to promote efficiency in the short or long run?

18. If transmission pricing arrangements should consider both the short and long run, what approach should the Commission take to determine the appropriate balance between these aims?

6 Relevant NEM Context

Before applying the concepts outlined in the previous chapter to the key issues for this Review, it is important to consider other relevant arrangements within the NEM. This is important because the Rules that govern the setting of transmission prices need to work alongside the wholesale market arrangements and other NEM processes.

The Commission considers that the key features of the NEM that should be taken into account in this Review are:

- Existing price and non-price signals for generation and consumption and investment in both generators and load projects (section 6.1) – these signals may reduce or obviate the need for the transmission pricing regime to provide longer run economic signals; and
- Distribution pricing arrangements (section 6.2) – these arrangements may limit the utility of attempting to provide sophisticated economic signals to end-use customers connected to distribution networks.

Understanding these other features of the NEM will assist in determining how the transmission pricing regime can best meet the NEM objective. In particular, in light of these features, it may be necessary to consider whether the theoretical benefits from a change to the pricing Rules may be insufficient to outweigh the transitional and ongoing costs of change. This is an important consideration for the Commission. The Commission is concerned not to change the current pricing arrangements without clear evidence that there will be a demonstrable net gain.

6.1 Price and Other Economic Signals in the NEM

The Commission considers that it is important for the transmission pricing arrangements to complement the consumption, production and investment signals provided by other aspects of the NEM arrangements. To this end, the following section briefly describes the NEM arrangements that already provide incentives to generators, consumers and investors to behave efficiently. These features are:

- regional pricing structure (section 6.1.1);
- non-firm grid access for generators (section 6.1.2); and
- the transmission investment arrangements, including the Regulatory Test (section 6.1.3).

In this context, the Commission reiterates that although these features are important to the development of transmission pricing Rules, they will not themselves be the subject of this Review. This implies, in particular, that the creation of property rights over the shared network will not be considered. It also means that greater specification of generators' access network rights – as requested in The Group, AGL and VENCorp submissions[26] – will not be addressed in this Review. The issue of compensation payments from one network user to another will also not be considered as these obligations may create *de facto* shared transmission property rights.

6.1.1 Regional Pricing Structure

One key feature of the NEM is its regional pricing structure. The NEM is currently made up of five regions, broadly corresponding to jurisdictional boundaries. The price at each regional reference node reflects the relative scarcity of electricity at that location. If there were no transmission losses or constraints, the price of electricity would be the same across the NEM.

The NEM deals with transmission losses and constraints differently depending on whether they arise on interconnectors between regions or on intra-regional lines. The presence of losses and constraints on interconnectors typically causes the price in an importing region to be higher than the price in the adjoining exporting region. Generally speaking, electricity flows from regions experiencing relatively low prices to regions experiencing relatively high prices. The stylised Victoria-South Australia example in Figure 2 shows how regional reference prices in the NEM can reflect the value of inter-regional constraints. Where transmission constraints occur on interconnectors and are reflected in regional price differences, producers and consumers of electricity will have incentives to produce and consume efficiently, at least in the short term. Where constraints arise within regions, the cost is smeared across the relevant region and participants may not receive efficient signals.

Other things being equal, the divergence of regional prices provides some incentives for:

- generators to produce more in regions experiencing higher prices than in regions experiencing lower prices;
- loads to consume less in regions experiencing higher prices than in regions experiencing lower prices;
- proponents of new generation projects to invest in locations expected to experience higher prices; and
- proponents of new load projects to invest in locations expected to experience lower prices.

If the Commission's sole concern is economic efficiency in the short run, the only role of the transmission pricing regime is to set prices to reflect all expected transmission constraints and losses not already reflected in the wholesale market. To recover the remaining (fixed) TNSP costs, the Commission would just then set a minimally distorting additional charge.

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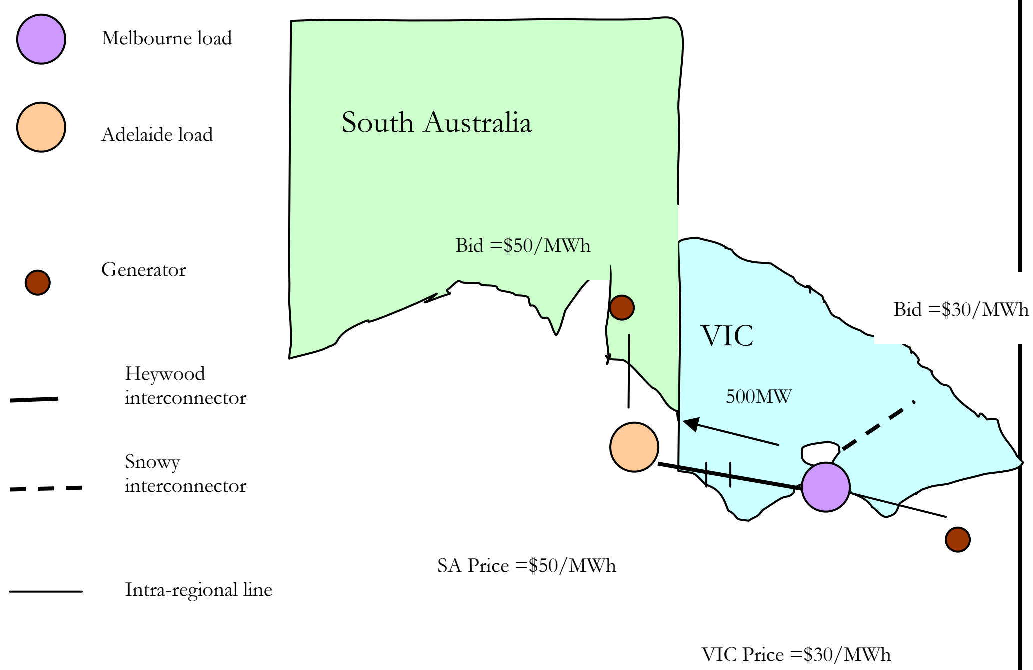
26 The Group submission, pp.7-8; AGL submission, section 3.1; VENCorp submission, p.2



Assume that electricity is flowing from Victoria to South Australia via the Heywood interconnector. Assume that the Victorian generator offers $30/MWh and the South Australian generator offers $50/MWh to produce an unlimited amount of power. In the absence of transmission constraints (and losses), the price at both the Victorian and South Australian regions would be $30/MWh. However, assume now that there is a maximum transfer limit on Heywood interconnector of 500 MW and that the Adelaide load is such that it cannot be fully met by the cheaper Victorian generator. Under these circumstances, NEMMCO is required to dispatch the more expensive ($50/MWh) South Australian generator when the capacity limit of Heywood has been reached. At this point the South Australian price will rise to $50/MWh. The cost of this constraint to the market is the price difference between the two regions ($20/MWh) multiplied by the South Australian load.

Figure 2: A simplified example of the effects of an inter-regional constraint

6.1.2 Non-firm Generator Access

The existing Rules and jurisdictional licences oblige TNSPs to plan and develop their networks to meet certain reliability and performance standards. These standards – and hence regulated transmission investments – are largely orientated towards serving loads reliably. There are no equivalent general standards or obligations on TNSPs to provide a certain level of power transfer capacity to generators. Those obligations that may be in place would have come into being through specific connection agreements.

Therefore, as a general matter, generators face non-firm access to the NEM transmission system.

If there is sufficient transmission capability for a generator to be dispatched, and if its bid is accepted by the National Electricity Market Management Company (NEMMCO), it will be dispatched. However, if the bid is not accepted or there is insufficient transmission capability, it will not be dispatched. Such non-firm access provides a further economic signal to potential generators regarding their locational decisions.

Non-firm access means that generator proponents should only locate in an area that has sufficient current and expected future transmission capacity for them to evacuate enough power to be profitable. This could either mean that:

- there is plentiful transmission capacity both now and in the future – in which case, it is efficient for the new plant to utilise the spare capacity that is available;

- there is limited transmission capacity available but the proposed generator is sufficiently lower cost than incumbents to regularly displace incumbents in the dispatch process – this is consistent with efficient utilisation of the existing network; or

- there is limited transmission capacity available, but an augmentation is expected to meet the requirements of the Regulatory Test (see below) – a generation investment made on this basis would be consistent with minimising the overall cost of electricity supply.

If a generator proponent behaves in accordance with these long run signals, it is likely that its investment decision will be efficient from a locational point of view.

6.1.3 Regulatory Test

The Regulatory Test for transmission investment provides another economic signal, particularly to generation and its alternatives, about efficient location. As noted above, a potential generator seeking to sell its power to the market will have an incentive to locate in areas either where network capacity is plentiful or where augmentation is likely to be approved under the Regulatory Test.

An augmentation will only satisfy the Test where it is the least cost or most net beneficial option compared to a range of practicable alternatives. Practicability requires that a project either has a proponent (for a 'reliability' augmentation) or would otherwise be likely to go ahead but for the proposed augmentation.

Therefore, proponents of generation and other projects need to consider the likely outcomes of the Regulatory Test before investing in a project that either:

- relies on a regulated augmentation proceeding to make the project viable (for example, a proposed generation project in Queensland may rely heavily on an upgrade of QNI to be viable); or

- relies on a regulated augmentation not proceeding to make the project viable (for example, a proposed embedded generator or DSM project in Sydney may not be viable if an upgrade of QNI is commissioned).

This provides useful long term locational signals to generators. Generators will only have incentives to locate in areas with little or no transmission capacity where they are confident that a transmission augmentation would satisfy the Regulatory Test.

Where this is the case, it would be efficient for both:

- the investor to develop generation in an area requiring network augmentation; and

- the network augmentation to proceed.

Appendix 1 provides more detailed examples of how the Regulatory Test may provide efficient locational signals for generators and alternative sources of supply.

If a by-product of the Regulatory Test is that it provides reasonable locational signals to generators and their alternatives, combined with non-firm access and the signals provided by regional wholesale prices, the requirement for transmission price signals may be reduced.

19. To what extent are existing signals from other aspects of the NEM arrangements (or requirements from regulatory settings outside the NEM) sufficient to promote efficient behaviour by actual and potential consumers and producers of electricity in the short and long run?

6.2 Distribution Network Pricing Arrangements

As identified in section 2.3, two important considerations in reviewing the role of transmission pricing are:

- the extent to which signals are likely to be preserved in end-users' bills; and

- the extent to which consumers are in a position to respond to those signals.

In the NEM, end-users connected to distribution networks (which are the overwhelming majority of end-users in number and a substantial majority of overall load) may not be faced with a transmission pricing structure imposed by the Rules, the AER or even the TNSP. Clause 6.13.7(b) of the existing Rules provides that transmission costs must be allocated to (distribution) asset categories by DNSPs using an appropriate methodology agreed with the jurisdictional regulator and consistent with the objectives of the distribution pricing regime set out in clause 6.10.2(b)(4). That clause requires that where end-use customers have appropriate metering technology in place, distribution prices to those customers should preserve the locational and time signals of the customer TUoS usage charge. However, there is no mention of preserving signals to other types of customers or in relation to other prices.

At this stage, the provisions governing distribution pricing are not within the scope of the AEMC's responsibilities.

Given the level of dilution of transmission charging structures most end-use customers are likely to face, this begs the question as to the value of prescribing transmission pricing structures in the Rules. Complicated structures designed to produce incremental benefits may be diluted or averaged by the DNSP. At the same time, new pricing structures may cause material transitional costs as TNSPs interpret and implement changes to their pricing methodologies. The overall effect may not promote the NEM objective. Conversely, prescribing Rules for charges to generators or large directly-connected loads may be more worthwhile.

20. Given current distribution network pricing arrangements, is it appropriate to prescribe transmission pricing structures in the Rules?

21. If so, should prescription be limited to prices for particular network users?

7 Allocation of Regulated Revenue Across Transmission Users

Chapter 4 of this Paper outlined the current transmission pricing arrangements in the Rules. This included how the Rules provide a mechanism for how TNSP regulated revenue is allocated and recovered from different network users and the pricing structure that applies for each charge.

This chapter briefly explores alternative ways to allocate the recovery of transmission revenues to network users. The next chapter explores alternative pricing structures through which TNSPs' regulated revenue could be recovered. These issues are only relevant if it is considered that some form of prescriptive regulation of price is required to satisfy the NEM objective.

The allocation of transmission costs to particular users is a multi-faceted issue. At the highest level is the broad question of which side of the market – generation or loads – should pay network charges, or alternatively, what the split of charges should be. This topic is discussed in chapter 8. The next issue is how a TNSP's regulated revenue should be allocated as between generators and as between loads. This involves consideration of different allocation methodologies including alternatives to CRNP. This is examined in section 7.2.2.

The appropriateness of prudent discounts to price sensitive loads and rebates to embedded generators is discussed in section 7.3.2.1.

7.1 Allocation of TNSP Regulated Revenue between User Classes

As noted in the previous chapter, network users pay shallow connection costs and loads pay the majority of shared network charges under the current Rules.

7.1.1 Payment and Incidence

Chapter 5 provided a framework for transmission pricing that can be applied to the question of who should pay for transmission costs. But before going on to consider this question, it is important to note that there is a distinction between who pays a charge and who ultimately incurs the cost of the charge. That is, there is a distinction between payment and incidence.

Whether the market is perfectly competitive or not, any charge levied on producers will, sooner or later, find its way into customer charges. To the extent that a charge is levied on generators its ultimate incidence will be on customers. This is not say that levying charges on generators cannot also have desirable outcomes. For example, charges that are higher in some locations than in others would cause generators to choose their connection point carefully and this may reduce the overall cost of providing transmission services. Therefore, it is worth considering whether there are meaningful efficiency benefits associated with imposing any transmission charges on generators, having regard to the incentive properties of other arrangements in the NEM (such as non-firm access). However, the costs of changing from the current arrangements to one where generators pay more of a TNSP's costs would have to be netted against any potential benefits. In this context, it is worth distinguishing between connection and shared network assets.

7.1.2 Connection Charges

As discussed in chapter 4 of this Paper, it is possible to adopt shallow or deep definitions of connection, and hence, connection charges. The key distinction is the extent to which a generator has guaranteed access over which assets. In general, the deeper the connection charge the more difficult it is to define what specific assets are associated with a particular generator's connection. That is, these assets become increasingly part of the shared, or meshed grid, which everybody uses. This makes it more difficult to assign any property rights to a generator for the connection assets they have paid for and this may reduce clarity and increase uncertainty. Another implication of a deeper connection charge is that generators may pay proportionately more of a TNSP's costs than under the current arrangements in the NEM.

Submissions by The Group, Total Environment Centre, AGL and VENCorp supported consideration of deeper connection charges for generators.[27] Indeed, VENCorp has already developed guidelines to address the issue of when deeper connection charges should apply.[28] Transend suggested that greater clarity over new connection charges and the scope of regulated services would be valuable.[29]

7.1.2.1 Shallow connection

Under a shallow connection charge regime (as currently in place in the NEM), users effectively pay only for assets specifically required to connect the user to the existing network. Such assets are typically the subject of a contract between the TNSP and the connecting party conferring rights of exclusive use on the connected party. The connecting party may also own some connection assets.

Any augmentation of the rest of the network that improves the power transfer capability to or from the connection is recovered through shared network charges if it satisfies the Regulatory Test. Parties are also free to fund augmentations to the shared network if they wish. Depending on where the boundary is drawn between the types of assets counted as connection assets, the approach may be considered more or less shallow.[30]

Under a shallow connection approach, it makes sense to recover connection costs solely from the connected party. The lack of network spillovers affecting such assets mean that

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27 The Group submission, pp.7-8; Total Environment Centre submission, pp.6-7; AGL submission, section 3.1; VENCorp submission, p.3

28 VENCorp, *Victorian Electricity Transmission Network Connection Augmentation Guidelines*, August 2005

29 Transend submission, p.3

30 For example, including only substation assets as a basis for charging would result in a shallower charge than including substation assets and single and multiple spurs that serve to connect users to the main grid.

whether or not such costs are incurred is usually exclusively dependent on the decisions of the connecting party. Therefore, efficiency requires that connecting parties face these (incremental) costs when making connection decisions.

Apart from the NEM, shallow connection approaches are in place in Britain and Singapore.

7.1.2.2 Deep connection

Under a deep connection charge regime, the connecting party may be required to pay for any incremental investment elsewhere in the shared transmission network required to accommodate the new connection. The intent of a deep connection approach is to confront users with the full (long run) marginal costs of their connection decisions and thereby promote long run efficiency.

Importantly, however, such investment may benefit (or harm) third parties, given the potential for network spillovers to occur from the investment. This makes efficient charging more complicated under a deep connection approach than under a shallow approach.

Consider the stylised example in Figure 3. Generator A may pay for downstream augmentation to the shared network to improve the evacuation of its output. However, having done this, generator B may have an incentive to locate close to the augmented network and displace generator A from dispatch. The risk of third parties gaining the benefits of investment by the connecting party (ie, 'free riding') may deter connecting parties from being willing to pay for such investment. If given no choice but to pay such costs, prospective connecting parties may be inefficiently deterred from connecting.

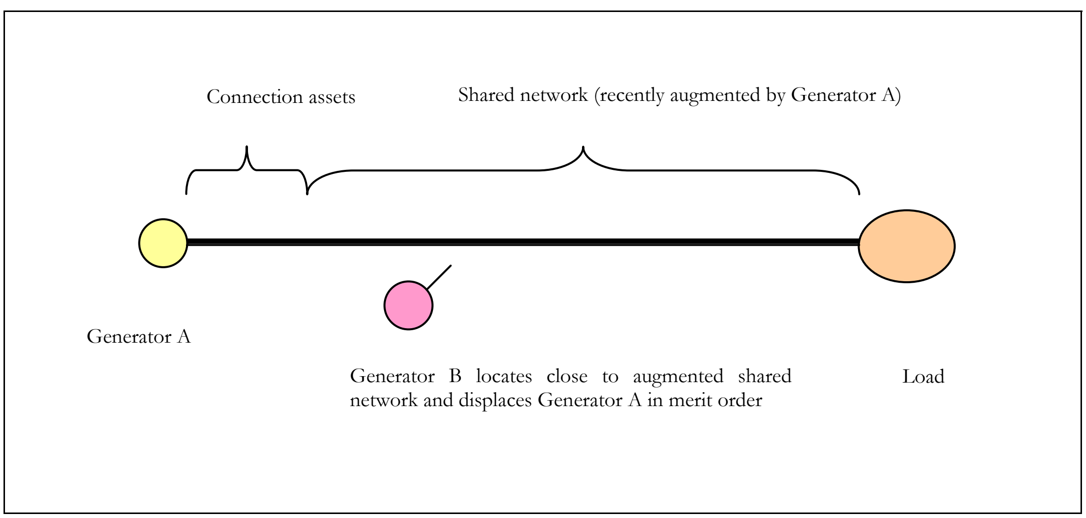

Figure 3: Free-rider problems with deep connection charges

Therefore, deep connection approaches – such as those in place in the United States – are often accompanied by property or quasi-property rights to prevent or limit free-riding. For example, in the Pennsylvania-New Jersey-Maryland (PJM) market, generators are required pay for certain downstream transmission upgrades if they wish to be certified as 'capacity resources'. Nearly all generators pay these charges because of the value attached to this status.[31] Roughly two-thirds of new regulated transmission capacity is paid for in this manner. The Swedish grid operator also imposes investment charges on some generators where such investment follows from a connection.[32] It is also worth noting that while the creation of property rights can be used to overcome free riding the presence of these property rights can create strong incentives for the owners of these rights to protect their value. This may work against the long term interests of the market if market participants are given incentives to frustrate the development of the grid.

In the NEM, where even relatively small transmission upgrades may have significant effects on power transfer capability, free riding is likely to be more of a problem than in PJM. This suggests that a deep connection approach may be more problematic. Arguably, this could be met by implementing a rebate system compensating the earlier user. However, in practice, the implementation difficulties with this may be considerable. That said, VENCorp's guidelines provide for such rebates within three years of an augmentation.[33] Regardless of the approach that is applied, the Commission would prefer to adopt a consistent approach to the arrangements across the NEM if there is to be regulated pricing. This consistency will reduce entry barriers, encourage greater competition and reduce prices for customers.

New Zealand currently has a deep connection regime, but it does not involve explicit charges for consequential upgrades following a new connection. Rather, both generators and loads pay a share of the regulatory costs of radial lines between their points of connection and the core grid.[34] The delineation between radial and core grid assets is carefully defined and assets may sometimes switch from connection to core and (occasionally) even back again.

22. Should NEM connection charges continue to be based on a shallow connection approach or should a deep connection approach be adopted?

23. If a shallow connection approach is broadly to be maintained, are there any circumstances where connecting parties should pay for up or downstream upgrades to the shared network?

24. If a deep connection approach is to be adopted in the NEM, how should it be formulated?

25. Is a deep connection approach compatible with the open access transmission regime of the NEM (which is not a subject of the present Review)? If so, how should potential "free-rider" effects be managed?

31 Joskow, P., L., *Patterns of Transmission Investment*, available at: http://web.mit.edu/ceepr/www/2005-004.pdf

32 Svenska Kraftnat, *Charges for utilizing the national grid*, 28 April 2003, available from: www.svk.se

33 VENCorp, *Victorian Electricity Transmission Network Connection Augmentation Guidelines*, August 2005, section 2.1(9), p.7

34 Transpower New Zealand Ltd, *Transmission Pricing Methodology*, May 2005, section 5, pp.7-18

7.1.3 Shared Network Charges

The shared network charges presently recover the majority of transmission revenues. There are two key efficiency-related considerations in determining who should contribute towards the recovery of TNSP regulated revenue:

- the need to have prices that recover fixed and sunk transmission costs in a non–distortionary manner ; and

- ensuring prices send signals to encourage the efficient use of the grid.

Both of these considerations derive from the intended role of transmission pricing as discussed in chapter 5.

7.1.3.1 Sunk cost recovery

To the extent other consumption, production and locational signals in the market are regarded as sufficient to promote efficient decisions, shared network charges can be used as a means of recovering outstanding fixed and common costs. In doing this, they should be levied in a manner that minimises distortions to participants' decisions. This would suggest that charges should be levied on the side of the market that is least sensitive to transmission charges.

7.1.3.2 Dynamic efficiency

The signals provided by the market arrangements may be considered inadequate from an efficiency perspective, especially in the long run. In these circumstances, shared network charges may be used as means of supplementing existing signals to encourage participants to make efficient decisions. For example, shared network charges may be recovered on a locational basis:

- To encourage efficient locational investment decisions, such as:

    - to encourage load to locate in generation-rich areas and deter load from locating in generation-poor areas;

    - to encourage generation to locate in generation-poor areas and deter generation from locating in generation-rich areas;

- To encourage efficient consumption and production decisions in the longer term by:

    - reducing consumption growth and increasing generation output in generation-poor areas; and

    - reducing generation output and increasing consumption growth in generation-rich areas.

Such behaviours could help reduce the need for (or delay) future network augmentation and save costs.[35] If network charges were used in this way, they should be allocated in a way that influences those whose decisions affect network investment.

In this context, it is worth discussing the merits of a 'beneficiary pays' approach to charging for new network investment as proposed by NECA.

As noted in chapter 4 of this paper, the Rules allow for generator charges for new network investment, although a charging methodology is not presently in place.[36] Such charges are distinguished from generator negotiated use of system charges, which are in respect of the shared network generally (ie, not new investment in particular).

NECA attempted to develop a beneficiary pays approach to new investment charges,[37] but this has not been implemented. In simple terms this approach allocated the costs of new transmission investment on the basis of the proportion of the benefits received from the investment. However, a precise methodology for determining such beneficiary shares was never fully developed.

The Commission notes that AGL's submission supported further work on the beneficiary pays concept, while CS Energy raised the issue of whether property rights should accompany payments made under such a regime.[38]

On the one hand, a beneficiary pays approach for new network investment has intuitive appeal because those that benefit are those that pay. This may mean that the transmission charge set on this basis has minimal distortionary effects.

On the other hand, the beneficiary pays approach has limited economic justification. This is because generators, particularly existing generators, have little influence on where, what type and how much transmission investment occurs. This differs from the provision of most private goods where the beneficiary is also the decision-maker (ie, the causer). Aside from the lack of theoretical backing for such an arrangement it is difficult to see how such a scheme could be put into practice. The calculation of benefit shares from a transmission investment would require a range of assumptions to be made, which would be likely to attract significant disputation.

7.1.3.3 Signals from other market and regulatory arrangements

As discussed in chapter 6, three existing features of the NEM may help promote efficient locational, consumption and production decisions. These features are:

- the regional pricing structure of the NEM;

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35 Locational charging methodologies are discussed in more detail in Section 4.2.

36 Clauses 6.4.3A(b) and 6.4.8 and schedule 6.8, National Electricity Rules

37 NECA, *Beneficiary Pays: A Framework for Implementation, Issues Paper*, May 2002

38 AGL submission, section 3.1; CS Energy submission, p.2

- the non-firm network access of generators; and

- the planning and investment arrangements (including the Regulatory Test).

As noted in chapter 6, if reasonable locational signals to generators and their alternatives are provided through these mechanisms, this may obviate the need to develop transmission pricing arrangements that seek achieve this outcome.

7.1.3.4 Approaches in other jurisdictions

It should be noted that many other jurisdictions impose shared network costs on generators. As discussed in section 7.2 below, the National Grid Company (NGC) in Britain imposes shared network charges (or rebates) on generators, as do transmission operators in Norway and Sweden. In the case of Britain and Sweden, generators pay about one quarter of shared network costs and these charges have a strong locational component designed to encourage efficient locational decisions. However, in Norway, where generators pay about one-third of shared network costs, generator charges are not locationally based.

26. Do signals from the regional pricing structure of the NEM, non-firm generator access and transmission investment arrangements provide efficient locational and operational signals to generators, loads and competing sources of energy supply?

27. Are there reasons why generators should make some contribution to shared network costs? If so, what approach should be used to determine the share of shared network costs should be paid by generators?

7.2 Allocation of Shared Network Costs within User Classes

Section 7.1 considered the overall allocation of TNSPs' regulated revenue recovery between generators and loads. This section focuses on the portion of regulated revenue relating to the shared network and discusses some of the issues that arise with the allocation of these costs within a user (loads or generators) class.

7.2.1 CRNP/Modified CRNP and LRMC

Chapter 4 of this Paper outlined the current CRNP and modified CRNP methodologies that are used in the NEM. These methodologies are used to allocate some shared network revenues to loads on a locational basis. CRNP and modified CRNP are intended to provide the basis for prices to reflect the LRMC of using the network at particular load connection points – even though the allocations are largely based on historic costs. As pointed out in chapter 5, whether it is appropriate for transmission prices to be set on the basis of LRMC – which is a forward looking concept - is debateable in itself, given:

- the compromises this may entail for network utilisation in the short term; and

- the economic signals for efficient use of the grid that are already created by other aspects of the NEM arrangements.

7.2.1.1 CRNP

If future patterns of transmission investment are similar to past patterns of investment (the costs of which dominate the calculation of CRNP prices), then the locational allocation produced by CRNP and LRMC may be similar.

However, problems arise where these assumptions do not hold. For example, due to scale economies it is generally cheaper to build the transmission grid in large lumps. This can create overcapacity for a period. Under the CRNP pricing framework the costs of building this lump of capacity, including the unused portion of this capacity, would be allocated to the users of these assets. The resulting high CRNP-based price could deter users from utilising this idle capacity even though in the short to medium term greater utilisation would not materially increase costs. In this way CRNP can potentially create inefficiencies.

The Australian Competition and Consumer Commission (ACCC) noted in its network pricing determination that CRNP does not take account of the existing SRMC signals from the energy market and so may 'oversignal' the costs of congestion.[39] By contrast, NECA's consultants had argued that a 50% allocation of shared network costs via the CRNP methodology could provide a reasonable surrogate for LRMC, at least on average.[40]

All of this suggests that CRNP may help provide a better proxy for LRMC in mature and highly meshed networks with reasonable load growth than in less meshed networks with 'lumpy' investment patterns.

Another point worth noting is that CRNP relies on complicated load flow modelling, which is very familiar to TNSPs as a power system planning tool. TNSPs already have models in place to derive CRNP-based prices. Any shift from CRNP (or modified CRNP) to another locational pricing methodology would be likely to involve material implementation costs.

Finally, it should be kept in mind that while at one level the CRNP methodology in the Rules appears prescriptive, at a more detailed level it involves a substantial degree of subjectivity and lack of transparency. The TNSP is required to allocate costs on the basis of operating conditions from the previous financial year that it has discretion to select. This may make it difficult for participants to conduct their own analysis to predict future price trends.

7.2.1.2 Modified CRNP

As noted in chapter 4, modified CRNP seeks to overcome the key shortcoming of CRNP (described above). Modified CRNP involves adjusting the revenue attributable to network elements allocated by the CRNP algorithm on the basis of utilisation. That is, if there is low utilisation of an asset and subsequently a high CRNP price, an adjustment would be made

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39 ACCC, *Network pricing and market network service providers*, 21 September 2001, p.29

40 NECA, *Transmission and Distribution Pricing Review*, Final Report, Volume II, July 1999, p.76

reduce the price in line with the low utilisation. This is done to encourage more efficient use of idle capacity.

Compared with CRNP, this modified CRNP approach should help produce revenue allocations that are:

- lower in areas where network utilisation is low (such that the expected present value of future augmentation costs is low); and

- higher in areas where network utilisation is high (such that augmentation is likely to be required in the short term).

Modified CRNP should therefore result in prices that more closely approximate the true LRMC of using the network than CRNP. This is because if there is a great deal of spare capacity it will be a long time before any additional investments would need to be made to meet the requirements of users.

The key drawback of modified CRNP is that, as with CRNP, it relies on the costs of the existing network providing a good indicator of future network costs. As identified above, this is unlikely to be true in less meshed parts of the network, such as Queensland.

Another drawback is the arbitrariness of the utilisation factor applied to network costs. For example, the methodology proposed in the NECA review involved adjusted network costs for utilisation as follows:[41]

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 ARR of the element.

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

These proportions were based on analysis by NECA's consultants that found that at about 80% network utilisation, a 50% allocation of shared network revenues via CRNP was a reasonable approximation of LRMC.[42] However, the relationship between utilisation levels and percentages will vary considerably across the grid and, therefore, at best will be a rough approximation of the relationship between CRNP and LRMC prices.

That said, as discussed in earlier chapters, developing a suitable pricing methodology will almost inevitably involve some degree of compromise and hence, some degree of arbitrariness. Also, while the CRNP methodology involves a great many arbitrary assumptions and involves complex and opaque modelling processes, the approach has the

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41 NECA, *Transmission and Distribution Pricing Review*, Final Report, Volume II, July 1999, p.61

42 NECA, *Transmission and Distribution Pricing Review*, Final Report, Volume II, July 1999, p.76

advantage of being familiar to TNSPs. The Commission understands that the determination of transmission prices using the existing approach is well developed, as far as the TNSPs are concerned, and involves little ongoing cost to maintain and update.

7.2.2 Alternative Allocation Approaches

There are a number of other options available for allocating TNSPs' regulated revenue within user classes. These are briefly discussed below.

7.2.2.1 LRMC

In the transmission and distribution pricing review, NECA proposed that TNSPs could have a choice between applying the CRNP, modified CRNP or LRMC methodologies throughout their networks. The proposed LRMC approach was based on charging (only) loads for the expected costs of augmentations contained in TNSPs' annual planning statements arising from expected load growth and generation development. This information would be used to develop a set of locational prices based on the identified costs and the reasons for each specific transmission augmentation. To this extent, prices would be heavily dependent on the assumed scenarios used in planning statements. NECA's report included sample LRMC prices for locations within Victoria developed with VPX.[43] The sample prices were generally less divergent across locations than the CRNP or modified CRNP approaches.

In developing its LRMC approach, NECA recognised that the determination of LRMC prices would involve a degree of subjectivity and potentially quite volatile prices. This was due to the degree of dependence on TNSPs' planning scenarios and the relatively short planning horizon compared to the lives of the assets involved. In a submission to the ACCC, TransGrid had pointed out that the LRMC charges could lead to very high charges in some areas (such as Lismore in their example) where significant network augmentation was required in the near term. This was because the LRMC calculation would be based on projected augmentations within the five year planning period, even though the lives of the relevant assets would be much longer.

An important point to note with NECA's LRMC methodology is that, like CRNP, it was a methodology for allocating a TNSP's revenue requirement to various connection points on a locational basis. Such an allocation process does not itself ensure that the prices network users face reflect the actual LRMC of network use. That depends on the pricing structure that is used to recover the regulated revenue allocated in this manner.

7.2.2.2 ICRP (Britain)

The NGC in Britain uses the Investment Cost Related Pricing methodology (ICRP).[44] Like CRNP, this is based on load-flow analysis, but the approach differs in a number of respects.

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43 NECA, *Transmission and Distribution Pricing Review*, Final Report, Volume II, July 1999, pp.76-80

44 NGC, *The Statement on the Use of System Charging Methodology*, 8 August 2005

First, the ICRP methodology is based on a direct current (DC) load flow transport model whereas CRNP is based on a more complicated alternating current (AC) model. ICRP estimates the impact on the expected costs of transmission investment of a 1 MW injection of electricity at a particular node, and a corresponding offtake at the reference node (in London), on the aggregate MW kilometres of electricity transported across the grid. This gives a marginal kilometre cost for generation at each node. The marginal kilometre cost of demand at each node is the exact opposite, as an increase in demand is the equivalent of a reduction in generation.[45]

The marginal kilometre cost is converted into a tariff, which is applied to demand, consumption and generation capacity. Therefore, unlike CRNP, ICRP tariffs are applied to generation as well as load. Another difference with CRNP is that for administrative simplicity, NGC allocates nodes to 14 demand zones and 21 generation zones, rather than setting unique prices for each connection point.[46] The ultimate pricing structure yields higher transmission prices for loads in the load-rich south of Britain than in the generation-rich north. It also yields relatively high charges for generation in the north with relatively low charges, or even rebates, for generators in the south.

One key feature of ICRP is that it is based on NGC's view on future investment costs rather than the costs of existing network assets, which is used in CRNP. This gives ICRP a forward-looking quality that is absent from CRNP. However, like CRNP, ICRP is based on an assumption of relatively small increments to transmission capacity and load. This may be more realistic assumption for the more mature British transmission system than for the fast-growing parts of the NEM, for example Queensland.

It should also be noted that NGC does not recover all shared network costs through the ICRP methodology – some costs (such as substation costs) are recovered through a non-locational residual tariff. It is also important to note that the British energy market does not have multiple pricing regions and therefore locational transmission prices play a more important than in the NEM.

7.2.2.3 Other locational approaches

As pointed out in the Bardak and Major Energy Consumers Coalition submissions to the Scoping Paper[47], several Scandinavian jurisdictions apply locational transmission charges to recover some shared network costs. For example, Norway applies point tariffs on both load and generation to reflect the cost of marginal losses.[48] Norway also applies a capacity charge to effectively adjust the spot prices paid or received by participants to reflect the cost of transmission constraints. Importantly, in Norway, the residual revenue of the transmission

45 NGC, *The Statement on the Use of System Charging Methodology*, 8 August 2005, pp.11-13

46 NGC, *The Statement on the Use of System Charging Methodology*, 8 August 2005, p.13

47 Bardak Group submission, pp.11-13 and attachment "Norwegian Paper on 'Point Tariff' system" (paper by Jon Sagen of NVE presented at the ConEnergy Conference, February 1998); Major Energy Consumers Coalition submission, p.7

48 Ministry of Petroleum and Energy, *Facts 2004, The energy sector and water resources in Norway*, pp.71-73

operator is recovered through non-locational charges. This may be because of the geographic dispersion of generators in that jurisdiction.

The pricing regime in Sweden is slightly different to Norway, in that the cost of constraints is not reflected in the ultimate energy price. Rather, Sweden imposes a locational capacity charge that is higher for generators in the generation-rich north of the country than in the south and lower for load in the north than in the south.[49] The expected cost of losses is recovered through a locational energy charge, similar as to what occurs in Norway. As noted in section 7.1.2, separate new investment charges may also apply.

The Scandinavian arrangements effectively use transmission charges to reflect the costs of losses and constraints. These are costs that are largely reflected in regional wholesale prices or dispatch in the NEM. On this basis, developing similar charges for the NEM may be inappropriate. In particular, such charges may inefficiently deter some generators and loads from locating in particular parts of the network. This highlights the importance of taking account of other aspects of the NEM – such as the structure of the energy market – in developing transmission pricing Rules.

7.2.2.4 Non-locational regulated revenue allocation approaches

All of the regulated revenue allocation approaches discussed above are based on providing LRMC-type signals to promote more efficient consumption, production or investment decisions in the long-term. However, an alternative view is that given the signals provided by other parts of the NEM arrangements, transmission pricing for the shared network should not be locationally based and should focus on minimising distortions to network usage. On this basis, the pricing approaches discussed in chapter 5 may be worth exploring – two part tariffs and Ramsey pricing. These options are discussed further in chapter 8 in the context of pricing structures.

28. Is the current shared network charging regime the best approach for achieving the NEM objective? If not, what improvements could be made?

29. Are there arrangements operating in other jurisdictions for the recovery of shared network costs that would be more appropriate for the NEM? If so, which jurisdictions and which aspects of their arrangements would be appropriate for the NEM?

49 Svenska Kraftnat, *Charges for utilizing the national grid*, 28 April 2003, available from: www.svk.se.

7.3 Prudent Discounts and TUoS Rebates

7.3.1 Prudent Discounts

The issue of discounts to certain users to avoid by-pass was discussed briefly in section 4.3 above. The following section considers the cost allocation surrounding the structure of discounted charges. The Alcoa submission in particular supported consideration of the prudent discount regime as part of this Review.[50]

7.3.1.1 Alternative approaches

A key issue of contention with the discounting regime is whether it is appropriate for the AER to have guidelines in place governing the terms under which discounts can be recovered from other users. Alternatively, such provisions could be contained in the Rules or eliminated altogether. There is an interaction here with the regulation of TNSP regulated revenue – given the risk of optimisation (which arguably no longer exists under the current arrangements), TNSPs will have incentives to negotiate with users who could potentially by-pass the system where a real risk of by-pass arises. However, without optimisation risk, these incentives may be diminished making it harder for users to negotiate discounts where this would otherwise be economic.

On the other hand, in order to reduce the risk of disputes with large well-resourced connecting loads, TNSPs may discount more than necessary to avoid inefficient by-pass. This could lead to higher (but still efficient) charges to less price-sensitive network users (such as DNSPs).

30. How much discretion should TNSPs have to discount charges?

31. Should TNSPs be entitled to recover the cost of discounts from other loads?

32. Should any conditions for recovering the cost of discounts from other customers be prescribed in the Rules or left to the AER to determine? If so, what should be the general content of these Rules or AER discretions?

50 Alcoa submission, p.1

7.3.2 TUoS Rebates

The issue of avoided TUoS rebates to embedded generators was also discussed in chapter of this paper. A number of submissions supported consideration of these rebates within the scope of the review.[51]

7.3.2.1 Alternative approaches

The key point to note about TUoS rebates is that they are intended to perform a locational investment and generation signalling function. That is, they are designed to promote efficient investment and operational decisions by actual or potential embedded generators. They are not designed primarily as a cost recovery mechanism. To the extent that the system of TUoS rebates is working well, this may further reduce the need for complicated pricing regulation. It may be that, combined with other signals in the NEM and TNSP incentives, there are sufficient locational signals already.

In this context, two opposing ways of characterising TUoS rebates are as follows:

- Existing TUoS rebates are inadequate because they only comprise the TUoS usage charge. This does not reflect the true LRMC of new transmission investment that would be avoided by an embedded generator[52]; and

- TUoS rebates should be a matter for negotiation between the DNSP and embedded generator.

The first approach is really a criticism of the CRNP methodology as an approximation of LRMC. To this extent, it raises broader issues than TUoS rebates. If CRNP is a poor approximation for LRMC, this may detrimentally affect the decisions of a range of network users.

Another approach is to allow TUoS rebates to be a matter for negotiation. Whether this is appropriate would depend on whether DNSPs have incentives to bargain reasonably with prospective and existing embedded generators over the avoided TUoS. Given the existence of multiple DNSPs in the NEM, it may be that DNSPs would be willing to share the benefits of reduced TUoS charges with embedded generators. The alternative may be that the embedded generator locates elsewhere and the DNSP loses the opportunity to make any savings on its TUoS bill.

33. Should avoided TUoS rebates be retained in the Rules or left for negotiation between the DNSP and connected party?

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51 For example, EnergyAustralia submission, p.11; Energy Action Group submission, p.6; Total Environment Centre submission, p.7

52 See Total Environment Centre submission, p.7

34. Is the appropriateness of TUoS rebates contingent on whether generators pay shared use of system charges?

35. If TUoS rebates are retained, what charges should they comprise?

8 Structure of Prices

8.1 Key Considerations

Having allocated connection and shared network costs to generation and load connection points, the final step is conversion of these costs to prices. The economic efficiency framework developed in chapter 5 and an understanding of other NEM features discussed in chapter 6 can be of use in evaluating alternative pricing structures.

Specifically, in order to maximise efficiency in the short run, prices should seek to reflect the SRMC of using the network. This suggests transmission pricing structure should not be based on the quantity of electricity consumed from or injected into the network. Charges based on network usage may deter utilisation of spare network capacity.

Conversely, in order to maximise efficiency in the long run, it will be necessary to depart from SRMC-type prices. At the least, some means of recovering a TNSP's outstanding physical infrastructure costs will be necessary. If transmission prices are not required to perform a signalling role, the appropriate way of recovering outstanding costs would be through a minimally distortionary charge. For example, fixed prices would tend not to influence network usage (so long as they were not large enough to encourage network by-pass). However, if dynamic efficiency considerations require transmission prices to signal the potential implications of increased network use on future augmentation costs, a charge based on LRMC that actually deters network use to some extent may be appropriate.

The existing Rules allow substantial latitude for the TNSP to determine price structures in relation to the customer usage charge. TNSPs may recover the usage charge using any combination of energy-based, capacity/demand-based or fixed charges. Section 2.1 discussed the nature of incentives TNSP face in terms pricing efficiently. However, the pricing structures for the customer general charge, common service charge and entry and exit charges are highly prescribed.

While this discretion for TNSPs reduces the level of regulation and may allow TNSPs to better reflect the costs of their network in the prices they charge, or allow them to better manage their risks, this could lead to differences in the way transmission is priced across the interconnected NEM. These inconsistencies have the potential of raising industry costs and customer prices. Thus, there is a trade off between the gains from TNSP having pricing discretion and the costs to customers in terms of paying for higher system costs and the possibility that TNSP do not price efficiently.

8.2 General Properties of Alternative Pricing Structures

As a general proposition, charges that are:

- Usage-based will deter usage of the network – this is because the more a customer uses the grid the more they will pay.

- Demand or capacity-based will act to reduce the extent of peak demand or need for greater capacity, respectively – this is because as peak demand or capacity increases, charges will rise. However, charges will not rise simply due to increased electricity consumption or production.

- Fixed, provided there is a suitable basis for levying them, should not cause users to alter their usage of the network or their peak demand or capacity levels - this is because the amount a user pays is invariant to the amount they consume, their peak demand or the capacity of their plant.

As with the allocation of TNSP regulated revenue between and amongst classes of network users, one of the key issues in determining appropriate charging structures is the intended role of the transmission pricing regime. If other NEM signals (ie regional price differences, lack of firm access, etc) provide adequate incentives to encourage reasonably efficient participant decision-making, prices should be structured to influence network usage as little as possible. This would suggest greater emphasis on fixed charges. However, if the pricing regime is intended to alter behaviour, then demand/capacity or usage-based pricing may be more appropriate. Such prices could be set to approximate the LRMC of network use at a connection point. These prices could help slow the growth of network use and delay or avoid network investment.

8.3 TNSPs' Incentives on Pricing Methodology

If TNSPs have incentives under their regulatory arrangements to set transmission prices in accordance with the NEM objective, Rules or regulations to prescribe pricing methodology may be unnecessary or even harmful. As indicated in chapter 2, it is possible that the TNSPs incentives are aligned to set prices that may be efficient in the short term but it is questionable whether this holds for the longer term.

As discussed in chapter 2, it is possible that revenue or price-cap regulation creates incentives for TNSPs to set prices in a way that minimises the deterrence to the use of the network – ie, to maximise utilisation of the network. These incentives may be reduced under a revenue cap regime with no optimisation risk.

Nevertheless, to the extent TNSPs are incentivised to price to maximise network utilisation, it is worth considering how they might do this. Two means of setting charges in this way that were referred to above are two part tariffs and Ramsey pricing. These were introduced in section 5.2.

8.3.1 Two-part Tariff

A conventional two-part tariff relies on one price being set to reflect either SRMC or LRMC and another non-usage based charge used to recover remaining costs. In the NEM, the energy market is already intended to reflect SRMCs (although the extent to which it can do this depends on the regional boundary criteria and their application). As for the non-usage-based charge, the existing customer general charge provides a loose approximation of this. The customer general price is presently set on the basis of historical (rather than present) consumption. This would help reduce, but not eliminate, the incentive for connected loads to curb their consumption. Therefore, it does not fully meet the requirements for the non-usage component of a two-part tariff.

8.3.2 Ramsey Pricing

As noted in section 5.2, Ramsey pricing is heavily information intensive because, in its pure form, it effectively requires a customised price for each network user based on their relative willingness to pay for network services. However, enabling TNSPs to provide (and recover the cost of) prudent discounts is one way of implementing a form of Ramsey pricing, at least for large directly-connected loads.

8.3.3 Dynamic Efficiency

Long run efficiency is likely to imply that transmission prices reflect LRMC and thereby slow the growth of, or reduce, network usage, relative to SRMC-based price structures. This has very different implications for appropriate pricing structure than a desire to promote short run efficiency. Fixed charges will tend not to slow or reduce network usage. Price structures based on consumption, injections, demand or generation capacity are more likely to have the desired impact. This is because such prices increase the marginal costs users face of increasing their consumption, injections, demand or capacity, respectively.

If the pricing methodology is required to send longer term consumption, production or locational signals to participants rather than maximise network utilisation, it would appear that TNSPs do not have clear incentives to set prices in this manner. The NEM objective refers to the long term interests of consumers, which is based on minimising the overall long term costs of supply. But TNSPs do not have inherent incentives to pursue this goal. Therefore, if prices are required to perform a longer term signalling role, some degree of prescription in the Rules, or elsewhere, may be required. For example, under these circumstances, if a TNSP were given discretion over the structure of prices the regulator's role in administering the arrangements to control how much investment is undertaken in the grid would become far more important and difficult.

36. To what extent is it necessary or worthwhile to prescribe transmission pricing structures in the Rules in order to promote the NEM objective?

37. Would it be appropriate to provide guidance to TNSPs on what pricing should achieve instead of prescribing the structure? If prescription is required, which charges should have price structures prescribed in most detail?

38. Should the degree of pricing structure prescription vary depending on the relevant class of network user paying the charge? If so, how could this be implemented?

39. How much discretion over charging structures should be left to the TNSP and the AER?

9 Pricing of Non-prescribed Services

The previous chapters have discussed the Rules relating to the pricing of transmission services that are regulated under the current revenue cap. The Rules refer to these services as 'prescribed transmission services.'[53]

Not all of the services provided by a TNSP fall within the revenue cap. The current Rules make provision for two distinct categories of service to be treated outside the scope of the revenue cap – certain excluded non-contestable services and contestable services. These services are referred to in this chapter as 'non-prescribed services'.

This chapter raises the issue of whether there should be Rules relating to the pricing for services that fall outside of the main regulatory control and, if so, what these Rules should cover. The Commission's earlier Issues Paper in relation to Revenue Requirements raised the issue of whether a multi-layered approach to the regulation of transmission services was appropriate. Whether or not such an approach is adopted may be expected to impact on decisions on the appropriate Rules relating to the pricing of services outside of the main regulatory control.

9.1 Existing Arrangements

The Rules specify that some non-contestable transmission services fall outside the operation of the revenue cap.[54] These are:

- negotiated generator and MNSP access charges;[55]
- that part of a prescribed transmission service which is provided to a standard which is higher or lower that any standard described in schedule 5.1 to the Rules, outlined in the standards published in accordance with clause 6.5.7(b) of the Rules, or required by any regulator regime administered by the AER;[56] and
- excluded transmission services.[57]

These services are provided on the basis of negotiation, with mediation and arbitration provisions included in the Rules.[58] Prices for such excluded non-contestable services are therefore determined from the outcome of this negotiation. For example, the outcome of the negotiation may be an agreed pricing formula for the term of the agreement.

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53 Ch 10 Glossary, National Electricity Rules

54 Chapter 6 of the *Revenue Requirements: Issues Paper* discussed non-prescribed services in detail.

55 Clause 6.5.3(b), National Electricity Rules

56 Clause 6.4.3(b)(5), National Electricity Rules

57 Ch 10, glossary 'Excluded transmission services', National Electricity Rules

58 Ch 10, glossary 'Negotiable service', National Electricity Rules. In addition to the services discussed above which are excluded from the revenue cap, there are other negotiated services that do fall within the revenue cap.

In addition the Rules allow for the identification by the AER of contestable transmission services, to which a more light-handed form of regulation applies.[59] The Rules do not prescribe the form of this regulation or how prices for these services are to be determined.

9.2 Alternative Approaches

Currently there are no criteria contained in the Rules relating to the basis on which prices for non-prescribed services should be determined.

Pricing outcomes for excluded non-contestable services are therefore left up to the negotiation process. An alternative approach would be to set out principles or criteria in the Rules which the TNSP and customer are required to have regard to in undertaking the negotiations in relation to price, and which would be taken into account in any dispute resolution process.

Pricing outcomes for contestable services will depend on the form of regulation adopted for those services.

40. Are the negotiation provisions in the Rules regarding prices for non-prescribed services appropriate? What difficulties (if any) have been experienced?

41. Should Rules provide criteria in relation to pricing outcomes for non-prescribed services?

42. Should a price monitoring regime be considered for non-prescribed services?

43. If so, what criteria would be appropriate? Would these be the same for all non-prescribed services?

44. Are the current dispute resolution provisions in Chapter 8 of the Rules appropriate for disputes over pricing of non-prescribed services? What (if any) alternative dispute resolution processes may be appropriate?

59 Clause 6.2.3(c), National Electricity Rules

10 Inter-regional Issues

When electricity flows between regions, the provision of electricity to customers in the importing region will involve the use of the network in the exporting region. However, TUoS charges in the importing region are based on the costs of the TNSP in the importing region only and do not reflect the costs of utilising the assets of a network in an adjacent region. An issue therefore arises as to whether there should be TUoS payments between jurisdictions to reflect this network utilisation.

The National Electricity Code originally contained a moratorium on the payment of TUoS charges across regions until a national transmission pricing methodology was developed and implemented.[60] Instead of inter-regional TUoS charges, clause 3.6.5 of the Code (now the Rules) provides the TNSP in the region importing electricity with the relevant inter-regional settlements residue on the basis that this TNSP makes negotiated payments to the exporting region for use of its network assets.

The ACCC has twice authorised an extension of the expiry date of the payment of inter-regional settlements residue.[61] Unless there is a Rule change that extends the arrangements, the current provisions will lapse on 1 July 2006.

10.1 Existing Arrangements

Inter-regional settlement residue is the surplus of funds retained by NEMMCO due to the difference between the value of energy in one region and the value of that energy once it has been transferred to another region. This difference in value is primarily due to the price difference between regions. The price differences can be due to the applications of inter-regional transmission constraints or (to a lesser extent) the marginal loss factors that apply between regions.[62]

The Rules set out how the inter-regional settlement residue is to be allocated, distributed and recovered. NEMMCO may auction the right to any inter-regional settlements residues allocated to a directional interconnector[63] for a specified period of time.[64] After recovering any auction fees, the net proceeds from auctioning these settlement residues as well as any

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60 See ACCC, Application for Authorisation – Amendments to the National Electricity Code – Inter-regional settlements arrangements, 25 March 2004.

61 ACCC, *Applications for Authorisation – Amendments to the National Electricity Code – Interregional transfer of TUOS, treatment of losses, improvements to PASA, pricing under extreme conditions, demand-side participation and end-user advocacy*, 19 September 2001: ACCC, *Applications for Authorisation – Amendments to the National Electricity Code – Inter-regional settlements agreements,* 25 March 2004

62 Settlements residue also arise from intra-regional loss factors, and are distributed to the relevant TNSP. Settlements residue arising from intra-regional loss factors do not impact on the treatment of settlements residue that is attributable to regulated interconnectors.

63 For the purpose of clause 3.18 a regulated interconnector between 2 adjacent regions consists of 2 directional interconnectors, one involving a transfer from region A to region B, and one involving a transfer from region B to region A – see 3.18.1(c), National Electricity Rules.

64 See clause 3.18.2(a), National Electricity Rules

portion of the inter-regional settlements residue which was not auctioned are distributed by NEMMCO to the network service providers.[65]

The proceeds from the settlement residue attributable to regulated interconnectors are distributed by NEMMCO in accordance with clause 3.6.5(5):

> *"for the purposes of the distribution or recovery of settlements residue that is attributable to regulated interconnectors:*
>
> *(i) all of the settlements residue relating to electricity that is transferred from one region (the "exporting region") to another region (the "importing region") must be allocated to Network Service Providers in respect of a network located in the importing region (or part of a network located in the importing region);*
>
> *(ii) the importing region must, in respect of the period from market commencement until 1 July 2006, pay a charge to the exporting region reflecting the extent of the use of a network located in the exporting region (or part of a network located in the exporting region) to transfer the electricity from the exporting region to the importing region; and*
>
> *(iii) the amount of the charge described in clause 3.6.5(a)(5)(i) and (ii) must not exceed the amount of the settlements residue and must be agreed between the participating jurisdictions in which the importing region and the exporting region are located;*

That is, the proceeds from inter-regional settlement residues collected by NEMMCO are distributed to the importing region on the basis that it reaches an agreement to pay the exporting region for use of its network assets.

In addition, any portion of the settlements residue distributed to a network service provider will be used to offset TUoS usage charges.[66]

The Victorian and South Australian Governments are the only jurisdictions who have negotiated an agreement to pay for the use of an exporting region's assets.[67] This agreement expires on 30 June 2006.

One point to note is that there is an ambiguity in the current drafting of the Rules in that the term "settlements residue that is attributable to regulated interconnectors" in clause 3.6.5 appears to refer to both:

- the difference between the value of energy in one region and the value of that energy once it has been transferred to another region;[68] and

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65 See clause 3.18.4(a), National Electricity Rules

66 See clause 3.6.5(a)(6) and 6.3.1, National Electricity Rules

67 ESCOSA, Settlement Residue Actions and Network Rebates, April 2002, page 4

- the net proceeds raised by NEMMCO from the auctioning inter-regional settlement residues as well as those inter-regional settlements residue which was not auctioned.[69]

Specifically, clause 3.6.5 refers to the portion of the settlements residue attributable to regulated interconnectors being distributed or recovered in accordance with clause 3.18. Clause 3.18 in turn refers to the auctioning of that settlement residue and (in 3.18.4) the distribution of the 'proceeds from each auction' as well as any inter-regional settlements residue which was not auctioned, in accordance with clause 3.6.5. Under clause 3.6.5(5), however, where this distribution is discussed, rather than referring to the *proceeds* of the settlements residue the clause refers directly to the settlements residue.

45. Could the current provisions in the Rules regarding inter-regional TUoS payments be improved? If so, how?

46. What are the impediments, if any, to reaching interregional agreements?

47. Should the Rules provide criteria for determining the 'extent of use of a network'? If so, what criteria would be appropriate?

48. Is there a need for greater clarity in the Rules on the treatment of the negotiated charge paid by the importing region to the exporting region for the purposes of determining annual aggregate revenue requirement of a TNSP?

49. Would it be appropriate to extend the expiry date of clause 3.6.5(a)(5)(ii) from 1 July 2006 to 31 December 2006 to coincide with the conclusion of the Commission's review?

10.2 Alternative Arrangements

The most notable alternative to the existing arrangements would be to replace the current arrangements with a transmission pricing methodology that does accommodate inter-regional TUoS charges. This is discussed further below.

A less significant change would be to modify the current provisions to ensure that TNSPs do not have a potential incentive to facilitate inter-regional constraints. Under the current provisions, the level of payment to TNSPs is dependent on the value of inter-regional residues, ie, the greater is the price difference between regions the greater will be the inter-regional settlement payments. This is not an issue when TNSPs are regulated under a revenue cap as the inter-regional settlement payments are used to offset network usage

68 See clause 3.6.5(a)(2), National Electricity Rules

69 See clause 3.6.5(a)(5), National Electricity Rules

charges. However, under a price cap arrangement for TNSPs the current provisions may create an incentive to maximise inter-regional settlement payments.

50. Do the current, or alternative arrangements provide TNSPs with adequate incentives to invest in assets that facilitate electricity flows between adjacent jurisdictions? If not what improvements could be made?

51. Should the negotiations of inter-regional payments be between TNSPs rather than jurisdictional governments?

52. Should incentives/penalties be in place in the Rules to ensure that an inter-regional agreement is in place?

An alternative would be to replace the current provisions in clause 3.6.5 with a system of transmission pricing that directly accounted for interregional flows and allowed for interregional TUoS payments. This would certainly bring some clarity and consistency to the current arrangements.

The ACCC previously viewed the current arrangements as transitional and that the treatment of inter-regional residues should be considered within the context of a national transmission pricing methodology.[70] The previous extensions of the expiry date were to provide time for a national transmission pricing methodology to be developed and implemented while at the same time recognising the network costs that arise from inter-regional transmission.

In 2001 NECA as part of its transmission pricing review proposed a change that would allow a TNSP to compute usage charges for its region, including connections to downstream regions.[71] Each TNSP would then be allowed to bill its neighbouring downstream TNSPs annually, based on estimated flows between them, with the resulting financial transfers to be taken into account by each TNSP when calculating its general charges, so that the required total revenue was still recovered. The ACCC rejected this proposed change as it felt that the existing arrangements could allow price signals to network customers, and as a result it was not clear that the proposed amendments would deliver material benefits relative to the existing arrangements.

70 ACCC, *Applications for Authorisation – Amendments to the National Electricity Code – Inter-regional settlements agreements,* 25 March 2004, page 6

71 ACCC, *Applications for Authorisation – Amendments to the National Electricity Code – Interregional transfer of TUOS, treatment of losses, improvements to PASA, pricing under extreme conditions, demand-side participation and end-user advocacy*, 19 September 2001, page 59-61

53. Should the provisions of clause 3.6.5 be replaced by a modified approach to TUoS pricing more generally?

Appendix 1 – Locational Incentives from the Regulatory Test – example and analysis

Consider a stylised example of a new coal discovery in Queensland. Development of a new generator close to the coal field will lead to the need for the network to be augmented in order for any generator to fully evacuate its power and be viable. Such an augmentation would need to satisfy the Regulatory Test.

A remote coal-fired generator proponent will need to consider if the combined cost of the remote generator and the network augmentation is lower than the next best alternative option, say an embedded generator near Sydney. If not, the augmentation will not proceed under the Test and the remote generation project will not be viable. Assume that the total lifetime capital and operating cost (total cost) of the remote coal generator is $100 million, the total cost of the necessary augmentation is $50 million and that the total cost of the embedded generator alternative is $200 million. Assume also that both generation options produce the same pattern and quantity of lifetime output. On the basis of this information, the augmentation would be approved under the Test because it would promote the most efficient outcome (supply at a total cost of $150 million compared with $200 million for the embedded generator) (see Figure **6**6 and Figure 7).

Figure 6: Efficient locational signals from the Regulatory Test

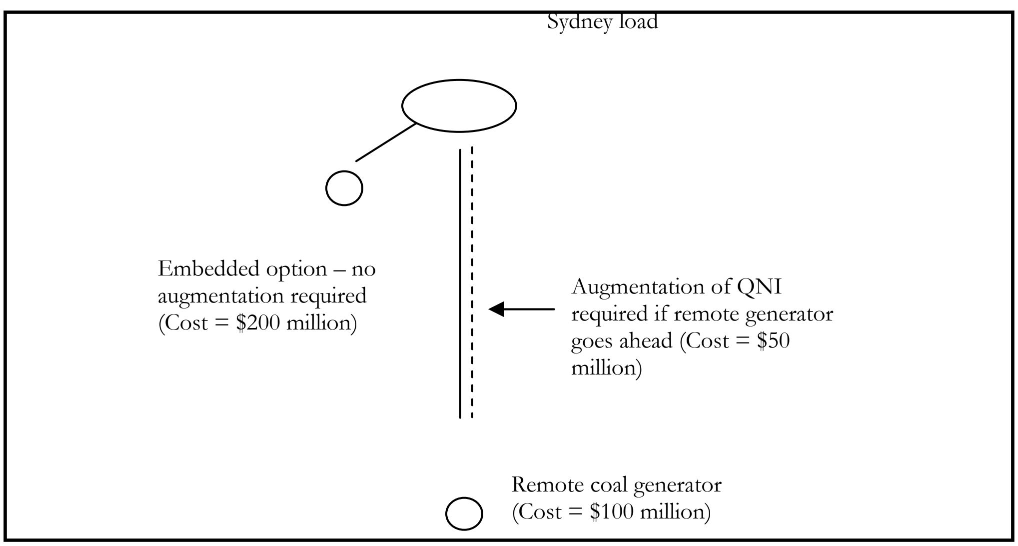


Figure 8: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option cost ($m)
Transmission	Augmentation	50	150
	Remote coal generation	100	
Generation	Embedded generation	200	200

The proponent of any investment will have an incentive to make such calculations internally, even before the Test is applied to the augmentation by the TNSP. For example, the remote generator proponent would have an incentive to conduct the analysis to gain some confidence that the augmentation would be approved and go ahead before it invests. The embedded generator proponent would also an incentive to conduct the analysis and would subsequently find it was not worthwhile to develop its project, as the augmentation, along with the remote generator option, are likely to go ahead and harm its proposed project. All of these outcomes are consistent with the objectives of the Regulatory Test.

Alternatively, if the cost of the remote coal generator is higher (say, $250 million) and combined with the cost of the augmentation ($300 million) is more than the embedded generator option ($200 million), neither the augmentation nor the remote generator will proceed (see 9). If the embedded generator proponent undertakes similar analysis, it will realise that its project is the most beneficial and it should proceed, on the basis that the augmentation is unlikely to go ahead and compromise the viability of its project. The remote generator proponent would realise that it was pointless to develop its plant.

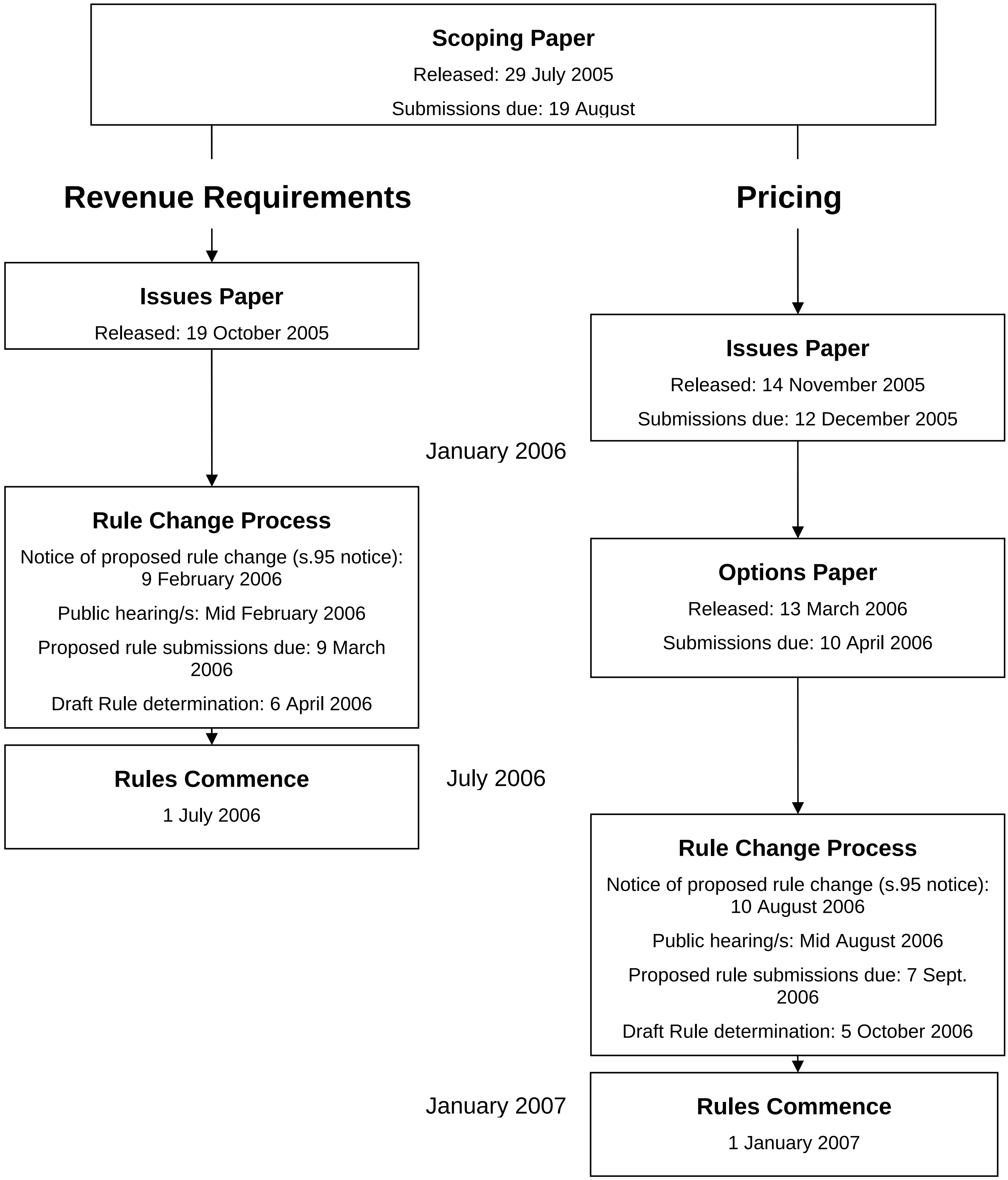
Figure 9: Transmission versus local generation – relative costs

Option	Includes	Total component costs ($m)	Total option cost ($m)
Transmission	Augmentation	50	300
	Remote coal generation	250	
Generation	Embedded generation	200	200

In this way, anticipation of the Regulatory Test should provide investors with efficient locational signals. It should be noted that such signals are provided by the Regulatory Test *by implication of its application*. Moreover, any separate charges to generators would have, in order to send efficient signals, to be based on a Regulatory Test-type analysis. Such prices could produce no more efficiency than the Regulatory Test itself would promote. Therefore, the incremental effect of generator charges on locational decisions is likely to be minimal, although if such charges are poorly derived they may harm locational investment efficiency.

In addition, Section 4.3 considers the current arrangements which allow rebates for embedded generation which may contribute to the avoidance or postponement of a transmission augmentation. However these arrangements may not be adequate to fully consider alternatives, such as demand side management and non electricity energy supply.

Attachment 1: Review Process



Attachment 2: Provisional Key Dates

Electricity Transmission Revenue and Pricing Review

Action Item	Issue: Revenue Requirements	Issue: Pricing	Action From: AEMC	Action From: Stakeholders	Date
Release of Process and Scoping Paper for transmission revenue requirements and pricing	✓	✓	✓		29 July 2005
Submissions due on Process and Scoping Paper for transmission revenue requirements and pricing	✓	✓		✓	19 August 2005
Release of Issues Paper for transmission revenue requirements	✓		✓		19 October 2005
Submission due on Issues Paper for transmission revenue requirements	✓			✓	16 November 2005
Release of Issues Paper for transmission pricing		✓	✓		14 November 2005
Submissions due on Issues Paper for transmission pricing		✓		✓	12 December 2005
Release of notice of proposed Rule for	✓		✓		9 February 2006

	Issue		Action From		
Action Item	**Revenue Requirements**	**Pricing**	**AEMC**	**Stakeholders**	**Date**
transmission revenue requirements (s.95)					
Public hearings for transmission revenue requirements (s.98)	✓		✓	✓	Mid February 2006
Submissions due on notice of proposed Rule for transmission revenue requirements (s.97)	✓			✓	9 March 2006
Release of Options Paper for transmission pricing		✓	✓		13 March 2006
Release of draft Rule determination for transmission revenue requirements (s.99)	✓		✓		6 April 2006
Submissions due on Options Paper for transmission pricing		✓	✓		10 April 2006
Deadline for interested person or body[72] to request the AEMC to hold a pre-final Rule determination hearing (s.101)		✓		✓	13 April 2006
Submissions due on draft Rule change for transmission revenue requirements (s.100)	✓			✓	18 May 2006
Pre-determination hearing for transmission revenue requirements (if requested) (s.101)	✓		✓	✓	27 April 2006

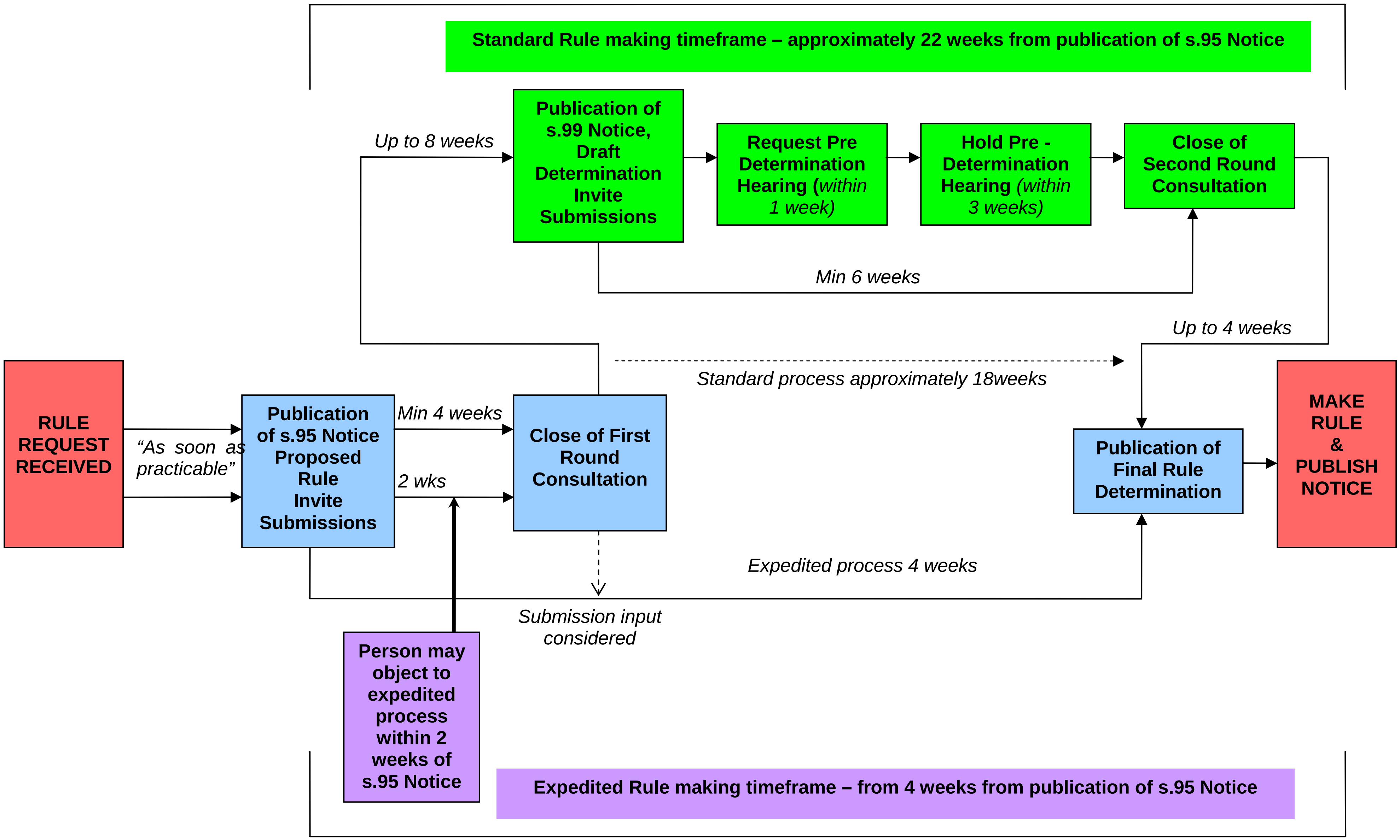
[72] An interested person or body means a person or body that has made a written submission or comment under s.97 or s.100 of the NEL

	Issue		Action From		
Action Item	**Revenue Requirements**	**Pricing**	**AEMC**	**Stakeholders**	**Date**
Release of final determination for transmission revenue requirements project (s.102)	✓		✓		15 June 2006
Rules commence for transmission revenue requirements project and options paper for transmission pricing (s.104)	✓		✓	✓	1 July 2006
Release of notice of proposed Rule for transmission pricing (s.95)		✓	✓		10 August 2006
Public hearings for transmission pricing (s.98)		✓	✓	✓	Mid August 2006
Submissions due on notice of proposed Rule for transmission pricing (s.97)		✓		✓	7 September 2006
Release of draft Rule determination for transmission pricing (s.99)		✓	✓		5 October 2006
Deadline for interested person or body[73] to request the AEMC to hold a pre-final Rule determination hearing (s.101)		✓		✓	12 October 2006
Pre-determination hearing(s) for transmission pricing (if requested) (s.101)		✓	✓	✓	Before 26 October 2006
Submission due on draft Rule change for		✓		✓	16 November 2006

[73] An interested person or body means a person or body that has made a written submission or comment under s.97 or s.100 of the NEL

Action Item	Issue: Revenue Requirements	Issue: Pricing	Action From: AEMC	Action From: Stakeholders	Date
transmission pricing (s.100)					
Release of Final determination for transmission pricing (s.102)		✓	✓		14 December 2006
Rules commence for transmission pricing		✓	✓	✓	1 January 2007

Attachment 3: Statutory Rule Making Process



Attachment 4: International Summary[1]

Market	Energy market and treatment of constraints and losses	Connection costs	Pricing for recovery of remaining shared network costs		
			Who pays?	Allocation methodology	Structure
Argentina	A single 'market node' is used to coordinate dispatch and pricing on an hourly basis by the market operator, CAMMESA. Other nodal prices are adjusted for losses and constraints. A separate generator capacity price is calculated annually at the market node and applied across the system by applying an 'adaptation factor' reflecting the reliability of transmission lines. Settlement residues arising from constraints are placed in an expansion account ('Exceed Fund'). Residues from constraints in a particular transmission 'corridor' can be used to recover up to 85% of the fixed costs of new transmission investment that reduces constraints in that corridor.	Shallow All users pay a connection charge based on cost of assets and O&M for their connection to the grid. If more than one user at a node, costs are pro-rated according to their maximum capacity requirement.	All 'users' of any line (which includes generators and loads – see across) pay for remaining shared line costs. Minor new investment (<2 million pesos) is undertaken by incumbent, TRANSENER, and costs smeared across all users. Major new investment is funded by the initiators (beneficiaries) of the project if they choose to contract for it directly. Nevertheless, there is open access to the line and charges are regulated. Major new investment is paid for by all users if contracted out by competitive tender, and approved by the Central Authority (ENRE). This requires initiators to have/get at least 30% of the use/benefit of the line. However, investment will be rejected if it is opposed by parties with 30% or more use in the line.	Remainder of regulated revenue is recovered through a 'Complementary Charge' on the 'users' of a line. A connected party is considered a 'user' of a line if it is within its 'area of influence'. A line is within a party's area of influence if an increase in the party's energy exchange produces an increase in the line's active power flow. The Complementary Charge is proportional to a party's 'use' of a line within the last 12 months. The 'use' and 'proportionality factor' are evaluated by CAMMESA every 3 months.	Variable transmission charges for losses and constraints are effectively recovered through the energy price. Separate Complementary Charge.

Market	Energy market and treatment of constraints and losses	Connection costs	Pricing for recovery of remaining shared network costs		
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			See also discussion of Exceed Fund (across).		
Australian (NEM)	Limited nodal (regional) energy market with inter-regional losses and constraints reflected in regional price differences. Intra-regional constraints reflected in higher wholesale prices and intra-regional losses reflected in fixed loss factors, which influence dispatch.	Shallow Generators and loads pay for 'entry' and 'exit' services provided by connected assets. Deeper network augmentation costs may be negotiated.	Loads pay all shared network and common service charges.	Costs are first allocated to network services (entry/exit, common service, shared). Shared network costs are recovered through both a locational usage charged based on CRNP or modified CRNP methodology and a general charge to recover the remainder of shared network revenues.	Entry and exist charges are fixed annual amounts. Rules allow for shared network customer usage charges to be demand-based, energy-based or fixed.
Chile	Dispatch and spot energy price for each system is based on merit order of declared and audited generator variable costs (SRMC). Regulated prices are based on a 4-year weighted-average forward-looking expectation of the spot price. Regulated prices at each location are adjusted by an energy penalisation factor (to reflect losses). Settlement residues from differences in energy prices due to losses are used to offset fixed charges. Also a node peak capacity price reflecting the annual marginal cost of increasing system	Shallow Connection entry and exit charges are regulated within a generator's defined zone of influence New generators have a right to connect to the network without any agreement on charges and settle charges via arbitration (open access).	Generators pay transmission costs. There are often lengthy disputes surrounding negotiations over charging.	Charges are negotiated around the concept of an 'influence area'. This is the area where the power is deemed to flow from generators to their customers. However, due to network externalities, this means some lines are not remunerated, even though they provide backup capability to the system as a whole. The recently passed 'Ley Corta' or Short Law is intended to increase regulation of transmission revenues to enable recovery of all transmission line costs and overcome an unwillingness to invest in transmission.	N/A

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	capacity assuming a specified reserve plant margin is calculated. This is also adjusted by a locational penalisation factor and paid to all generators.			Additive ('pancaked') transmission access charges apply for transactions that cross several transmission owners' areas. A separate access charge ('toll') calculated for each Transmission Owners' zone.	
Great Britain	No locally differentiated energy prices (contract trading with final cash out 'balancing mechanism' that penalises differences between contract and physical positions). Transmission losses are accounted for by scaling up, for each half-hour, each supplier's metered demand by the same amount, until the adjusted demand equals the metered generation scaled down by a uniform amount. Cost of transmission constraints recovered via balancing services use of system (BSUOS) charge on all participants (ie, socialized). NGC is incentivised to minimize the overall controllable cost of balancing, including congestion management.	Shallow Generators and loads pay 'shallow' connection costs. NGC levies site-specific connection charges for assets installed solely for the use of a single user or a specified group of users.	Generators pay 23% and Loads pay 77% of network use of system (TNUoS) revenue. Generators and loads pay equal share (50/50) of BSUoS charges.	ICRP based on a DC (direct current) load-flow transport model. The methodology estimates the impact of a 1 MW injection of electricity at a particular node, and a corresponding offtake at the reference node, on the aggregate MW kilometres of electricity transported across the grid. This gives a marginal kilometre cost for generation at each node. The marginal kilometre cost of demand at each node is the exact opposite, since an increase in demand is treated as the equivalent of a reduction in generation. The marginal kilometre cost is converted into a tariff by multiplying by an 'expansion constant' and a 'locational security factor' to arrive at a £/MW rate. This rate is applied to demand,	Large customers (suppliers) pay demand charges (at a £/MW rate) for their half-hourly metered customers, based on demand during system demand peak (defined at the 3 half hours of maximum system demand for the financial year that are separated by at least 10 days each – the 'Triad'). Suppliers also pay demand charges (at a p/kWh rate) for their non-half-hourly metered customers based on their consumption during the evening peak (4-7pm) over the financial year. All demand charges are positive, varying across 14 fixed demand zones, corresponding to the 14 GSP groups (ie, distribution networks). Generation charges vary across 21 zones. Charges are typically positive but may be negative (ie

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				consumption and generation capacity (see next column). Over- and under-recovery of shared network revenue is balanced through a non-locational Residual Tariff for generation and demand. This tariff also includes substation capital costs.	comprise rebates) in load-rich areas and generation zones may change between price control periods.
Korea	Cost-based pool operating where generators submit variable costs to KPX (market operator). There are separate prices for base load plant (BLMP) and other plant (SMP). There are also capacity payments (higher for base load plant than other plant). Constraints are handled through a re-dispatch and balancing arrangement and the cost (as well as the cost of losses) is recovered through an uplift. A marginal pricing system with demand and supply-side bidding and no capacity payment is planned.	N/A	Intention is for both loads and generators to pay on a locational basis.	Charges regionally will be differentiated based on 'transmission line usage', which in turn will be based on average MW transported over a line during an assessment period (at peak time). Generator charges will be higher in generation-rich areas and lower in load-rich areas. The converse will apply to load charges.	N/A
New Zealand	Nodal pricing approach where energy prices at a particular grid location, or node, are set by the marginal cost of generation set to meet the demand at that node.	Deep Generators and customers pay 'deep connection' costs, including direct connection and the	Offtake customers (consumers) pay for all of the shared AC core network (HVAC) costs through the 'Interconnection Charge'.	The Interconnection Charge rate (in $/kW) is determined annually by dividing that part of the HVAC revenue requirement not recovered via the connection charge by the sum of the estimates of the	Interconnection charge is applied to demand (in kW) at a grid exit point over the peak 12 hours over the previous 12 months, paid monthly. The HVDC monthly charge is

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	Transpower collects congestion rentals and rebates these to customers.	cost of the 'radial grid' (lines between the customer and the 'meshed' integrated core grid). Connection costs are shared between connected parties at each grid exit point on the basis of their proportion of annual maximum demand or annual maximum injections at that grid exit point. Charges are on a $/kW basis, charged monthly.	South Island generators pay the 'HVDC charge' to recover the cost of the inter-island DC link.	anytime maximum demand for the capacity measurement period at all points of supply from which electricity was taken off. The HVDC rate (in $/kW) is determined annually by dividing the HVDC revenue requirement by the sum of the estimates of all customers' peak injections into the grid system at South Island points of supply.	calculated separately for each injection point by multiplying the anytime maximum injection figure (in kW) for that year with the HVDC rate.
Norway	Part of the multi-national NordPool market, which includes (four) separate markets for spot trading, physical balancing, financial hedging and financial options. The cost of transmission losses is recovered via an energy-based component of 'Input' and 'Consumption' Point tariffs to generators and loads, respectively, intended to reflect marginal losses in the grid. Loss factors differ across locations, between periods, season and time of day. The cost of constraints is reflected in the difference	Shallow Generators and loads pay shallow connection costs, which are subject to a regulated cap, although networks can also charge non-regulated capital contributions. New customers either pay a share of connection charges each year to the network or get a refund on up-front payment as new customers are connected to the	Generators pay about 32% and loads pay about 68%, but it is not clear whether this includes the Capacity Charge reflecting the cost of constraints (see across).	Energy charges are based on losses. Non-locational charges recover the remainder of regulated revenue.	Generators pay an Input Point Tariff including: - a locational (per kWh) energy charge or rebate reflecting the cost of losses (a charge in surplus generation areas and a rebate in generation deficit areas); and - a postage-stamped rate based on *average* gross output (in kWh). Generators also pay or receive a Capacity Charge to reflect the cost of constraints. If they are in a zone with surplus generation during a constraint, they pay a Capacity Charge

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	between the unconstrained system price for the (entire) NordPool system, and the (constrained) balance price for the relevant price area/zone. The price difference is known as the 'Capacity Charge' (see across).	network.			reflecting the value of congestion and if they in a generation deficit zone, they receive a Capacity Charge reflecting the value of congestion. Loads pay a Consumption Point Tariff including a (per kWh) energy component covering losses. The Consumption Point Tariff also includes a fixed (amount per annum) component and a (net) maximum demand component (rate per kW peak demand).
Singapore	Nodal market with uniform customer price. Losses and transmission constraints are reflected in nodal price differentials.	Shallow Generators pay a charge based on a $/MW rate on installed capacity. Consumers generally pay an up-front service connection charge to connection to SP PowerAssets' substation/ network. Low voltage connected customers pay a standardised fee.	Loads only, through demand and energy charges.	No locational variation in either demand-based or energy-based charges (see across).	For higher-voltage customers (6.6kV and above), there are various capacity charges (contracted, uncontracted and standby uncontracted) (in $/kW/month). There are also peak and off-peak consumption-based energy charges (c/kWh). For lower-voltage customers, only consumption-based energy charges apply (c/kWh). These are on a peak/off-peak basis for time-of-use metered customers and anytime tariffs for other customers.
Sweden	No separate pricing zones (although Sweden is one zone of the multi-national NordPool	N/A	Generators pay about 25% and loads pay about 75%. Both pay a Capacity	Capacity charges (see across) recover about 60% shared network revenue.	Generators pay or receive an Energy Charge to recover the value of losses. Generators in

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	market – see Norway above). Losses are recovered through energy-based transmission charges on loads and generation (see across). Constraints are not reflected in locational price differences (unlike Norway). Rather, congestion is managed through 'counter-trade' by the system operator. The net cost of trades is charged recovered from customers through transmission tariffs as part of the balancing service. Also grid operator receives a share of the NordPool transmission rent.		Charge and an Energy Charge, the latter designed to recover the cost of losses (see across).	Energy Charges are based on marginal transmission losses. But the energy price used to 'top up' losses is purchased by the network operator a year in advance under contract.	surplus generation areas (ie the north) pay and generators in generation deficit areas (ie the south) receive these charges. Generators also pay a Capacity Charge based on capacity. This varies from SEK25/kW in the north to SEK5/kW in the south. Loads pay or receive an Energy Charge to recover the value of losses. In general, loads in the north receive this charge and loads in the south pay. Loads also pay a Capacity Charge, varying from SEK11/kW in the north to SEK47/kW in the south. Also in some cases, an Investment Charge applies where connection of a customer's plant entails investments not covered by normal charges.
USA California	*Prior to the energy crisis and at present*: - Zonal-differentiated energy prices. - At present, inter-zonal loss factors are applied. - the independent system operator (ISO) control area is divided into three congestion	Deep Generators pay deep connection charges. They get refunds if other generators use their assets. FERC introduced standardised interconnection rules for large generator	Loads pay access charges. 'Wheeling' customers pay a $/MWh fee. (Wheeling' refers to third party access to transmission transportation services).	Open Access Charges (OATT) apply to wheeling per kW of reserved capacity (point-to-point). An OATT rate is set for each TO within CAISO control area, based on average 12 CP. Load pays the OATT of the zone where they are located. For "drive out" of CAISO CA, a	Tariffs include an access fee to recover capital costs and usage fees to recover congestion costs. Rates can include a $/day or $/month per customer charge, a facilities-related charge (in $/kW) and/or and energy charge (c/kWh).

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	zones, with separate prices. The zones are: North of Path 15 (NP15), South of Path 15 (SP15), and Zone Path 26. - If a transaction spans the CAISO market then an additional ("pancaked") access charge may apply in the second jurisdiction. - Intra-zonal constraints are managed in real-time through the energy imbalance market. - Over-collection of losses used to offset fixed charges. Congestion Revenue Right (CRR) holders receive net congestion revenues for a specified inter-zonal interface. *After January 2007*: - Nodal energy prices (hourly LMPs) - Marginal locational loss factors will be a component of the LMP at each location. - Congestion will be priced at the difference between LMPs. - Over-collection of congestion and losses allocated to source-to-sink CRRs balancing account.	connections whereby generators have to pay for deep connection and can get refunds if other generators connect within 5 years.		combined OATT rate applies. By 2009, a postage-stamp access charge will apply in the entire CAISO system. Generator connection costs recovered in separate connection charges.	
USA PJM	Nodal pricing reflecting hourly	Deep	N/A	See across.	Three forms of service:

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	LMP at each node. Congestion is reflected in nodal energy price differentials. Average loss factors are applied. PJM is considering moving to marginal locational loss factors in 2006. Firm transmission customers are charged for congestion costs; non-firm customers do not pay for congestion. PJM collects settlement residues from differences in energy prices due to congestion, and these are used to fund FTR payments.	Both generators and loads pay connection charges and are allocated a share of network upgrade costs. No refunds but if a new project brings forward an upgrade, cost allocation of the augmentation may be affected accordingly.			- Network integration – equivalent to TUoS demand charges for retailers to pay in respect of their customers' consumption. Based on proportionate peak demand on the network in each transmission zone. Prices in the range of 15-25/kW/year. Retailers also receive FTRs; - Firm point-to-point short term (daily, weekly, monthly) and long term (>1 year) – for imports, exports and transit flows through PJM not covered by integration service. Prices are cost-based and allocated on peak demand; - Non-firm point-to-point (hourly, daily, weekly) – non-firm variant of above. However, users do not pay costs of congestion, on the basis that they are curtailed first. Two forms of network service: - Network integration and - Point-to-point. (firm and non-firm (for up to 24 consecutive hours)). Variety of transmission services including:

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					- Regional Network Service; - Internal Point-to-Point service (firm and non-firm); - Transaction-specific point-to-point through service (import, through and out). - Rates are $/kWh or $/kW rate for scheduled or reserved capacity. End consumers pay fixed charge ($/month), demand ($/kW) and energy ($/kWh). Demand is based on maximum 15 minute demand for the month. Loads pay. Generators do not have to pay for shared network costs although they must pay for: - Network upgrades required to restore reliability criteria, where their connection causes violation (although costs shared with other generators who are beneficiaries); and - Costs of meeting generator 'deliverability' criteria if they want to be certified as 'capacity resources' (which nearly all do because of the significant value available). NB About 65-75% of

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					transmission investments are included in one of these categories. Loads, subject to deep connection costs (see across).
USA New York ISO	Nodal pricing reflecting hourly LMP at each node. Transmission constraint charge is the difference in LMPs between the source and sink locations of the transaction. If a transaction spans the market boundary then an additional ("pancaked") access charge may apply in the second jurisdiction. Excess revenues from TCCs are credited against the transmission company's regulated revenue requirements.	Deep Generators pay for deep connection and network upgrades that are not part of the Annual Transmission Baseline Assessment. FERC's new standard interconnection rules apply (see California).	N/A	N/A	N/A
USA New England	Nodal pricing reflecting hourly LMP at each node. Transmission constraint charge is the difference in LMPs between the source and sink locations of the transaction. If a transaction spans the market boundary then an additional ("pancaked") access charge may apply in the second jurisdiction. ISO collects settlement residues from differences in energy	Deep Generators pay connection charges and FERC's rule applies (see California).	N/A	N/A	N/A

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	prices due to congestion, and these are used to fund FTR payments. Settlement residues from differences in energy prices due losses are used to offset fixed charges.				

Attachment 5: Submissions Received

1. A Solid Foundation;
2. AER;
3. AGL;
4. Alcoa;
5. Bardak;
6. Bev Smiles;
7. CS Energy;
8. Electricity Transmission Network Owners;
9. Energex;
10. Energy Networks Association;
11. Energy Users Association of Australia;
12. EnergyAustralia;
13. Energy Intensive Industries Alliance;
14. Ergon;
15. Hydro Tasmania;
16. Major Energy Consumers Coalition;
17. National Generators Forum;
18. NRG Flinders;
19. Total Environment Centre;
20. Transend;
21. TRU/International Power/Loy Yang/NRG Flinders; and
22. VENCorp

[1] Sources:

Argentina - *Ley de Emergencia Pública y de Reforma del Regimen Cambiario, 25.561, 6 de enero de 2002. ENRE Resolutions No 182/2000, 510/2001, 531/2001 y 692/2001* www.enre.gov.ar.

Chile - www.camara.cl/aindex/leyelec/ley.htm DFL N° 1 de 1982. www.cne.cl.

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New Zealand – *Commerce Commission, Regulation of Electricity Lines Businesses Targeted Control Regime: Resetting Transpower's Thresholds from 1 July 2005 Decisions Paper and Invitation for Submissions on Draft Gazette Notice, 6 May 2005.*

Norway – the Norwegian Water Resources and Energy Directorate. www.nve.no.

Singapore – Electricity Licence for Transmission Licensee: PowerGrid Limited, Transmission Code, www.ema.gov.sg.

Sweden –1997 Electricity Act and the Swedish Energy Agency. www.stem.se.

US - *NERA analysis. Example of Open Access Transmission Tariff (OATT) in New York ISO*. www.nyiso.com/public/index.jsp.