# Australian Energy Market Commission

## Draft Rule Determination

### Draft National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006

**Date:** **19 October 2006**

Signed: ..........................................................................

John Tamblyn
Chairman

For and on behalf of:
Australian Energy Market Commission

Commissioners: Tamblyn
Carver
Woodward

## Inquiries

The Australian Energy Market Commission
PO Box H166
Australia Square NSW 1215

**E:** aemc@aemc.gov.au
**T:** (02) 8296 7800
**F:** (02) 8296 7899

## Citation

AEMC 2006, *Draft National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006*, Draft Determination, 19 October 2006, Sydney.

## About the AEMC

The Council of Australian Governments, through its Ministerial Council on Energy, established the Australian Energy Market Commission (AEMC) in July 2005 to be the Rule maker for national energy market. The AEMC is currently responsible for Rules and policy advice covering the National Electricity Market. It is a statutory authority. Our key responsibilities are to consider Rule change proposals, conduct energy market reviews and provide policy advice to the Ministerial Council as requested, or on AEMC initiative.

# Preface

The National Electricity Law (NEL) requires the Australian Energy Market Commission (Commission) to amend the National Electricity Rules (NER) governing the regulation of electricity transmission revenue and prices before January 2007.

Publication of the Draft National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006 (Proposed Pricing Rule) and this Draft Determination represents an important step in the Commission's Rule change process in relation to the pricing regulation aspects of the review of transmission revenue and pricing (the Review). In conducting the Review, the Commission has placed an emphasis on the role that the transmission network has in facilitating competition and efficient resource use in the electricity wholesale and retail markets. The interactions of the transmission network with the competitive sectors of the electricity system, together with the market power that can be associated with the supply of certain transmission services, are the principal reasons why the Commission has sought to ensure that the transmission regulatory arrangements are effective in promoting efficient behaviour and outcomes across the market.

This Review of the Rules for the economic regulation of electricity transmission is part of a broader program of reform of the arrangements governing investment in, and operation of the national electricity transmission grid and its contribution to the efficient performance of the National Electricity Market (NEM) as a whole.

The Commission is currently processing a number of related Rule change proposals submitted by the Ministerial Council on Energy (MCE) that are concerned with facilitating timely and efficient transmission investments[1]. The MCE has also directed the Commission to review and recommend options for improved management of congestion in the transmission network (the Congestion Management Review or CMR). Under the auspices of the Commission, the Reliability Panel is also conducting a review of the reliability standards and related arrangements, which influence investment and support the reliability and performance of the national electricity system.

In developing the Draft Pricing Rule, the Commission has had careful regard to the work in the other related reviews, views expressed in submissions to the transmission pricing Issues Paper and Proposed Pricing Rule and to its review of transmission revenue rules. In particular:

- the CMR may have implications for the role of transmission pricing in the NEM; and

[1] MCE, Regulatory Test Rule Change Proposal, 12 October 2005, and MCE, Last Resort Planning Power Rule Change Proposal, 12 October 2005.

- the new arrangements proposed for negotiated transmission services in the Draft Revenue Rule[2] address issues surrounding the provision of, and pricing for, above or below standard services.

Taking all these matters into account, the Commission has developed a Draft Pricing Rule that is based on three key propositions:

- subject to the outcomes of other reviews being undertaken, there is no need for substantive change to the general means by which Transmission Network Service Providers (TNSPs) set prices for prescribed transmission services under the current Rules;

- the existing pricing Rules specify excessively detailed requirements for the implementation and administration of pricing methodologies; and

- the procedural requirements for developing TNSPs' pricing methodologies should be clarified to reflect the degree of codification in the Rules.

In line with these propositions, the Commission has developed a Draft Pricing Rule that largely confirms the continued operation of current pricing methodologies while also providing scope for innovation into the future. This has been achieved through a recasted regulatory framework incorporating codification in the Rules of the key design features of the regime including:

- principles for prescribed transmission service pricing methodologies (arrangements for the pricing of negotiated services have been dealt with in the Draft Revenue Rule);

- the option or requirement for the Australian Energy Regulator (AER) to make guidelines in specific areas of pricing implementation and administration; and

- clear procedural requirements for the development, implementation and administration of pricing methodologies.

The Commission considers that this approach is consistent with the Draft Revenue Rule and will further the NEM Objective.

The Commission is seeking views on the scope, construction and detailed drafting of the Draft Pricing Rule and the reasons provided in support of the approach in this Draft Determination.

After considering the views expressed in submissions and conducting its own further analysis, the Commission intends to publish a Final Determination and Final Rules in December 2006.

---

[2] Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006.

**Interested stakeholders are invited to make comment on the issues outcomes in this Draft Determination and Draft Rule.**

Submissions should be received by 5pm on Thursday 30 November 2006.

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

Fax (02) 8296 7899

# Contents

## Abbreviations

| | |
|---|---|
| AARR | Aggregate Annual Revenue Requirement |
| ACCC | Australian Competition and Consumer Commission |
| AEMC | Australian Energy Market Commission |
| AER | Australian Energy Regulator |
| AGL | Australian Gas Light Company |
| ASRR | Annual Service Revenue Requirement |
| CMR | Congestion Management Review |
| COAG | The Council of Australian Governments |
| Commission | See AEMC |
| CPI | Consumer Price Index |
| CRNP | Cost Reflective Network Pricing |
| DNSP | Distribution Network Service Provider |
| DORC | Depreciated Optimised Replacement Cost |
| DSM | Demand Side Management |
| EAG | Energy Action Group |
| ESCOSA | Essential Services Commission of South Australia |
| ETNOF | Electricity Transmission Network Owners' Forum |
| ETSA | ETSA Utilities |
| EUAA | Energy Users' Association of Australia |
| Gas Code | National Third Party Access Code for Natural Gas Pipelines |
| Gas Access Regime | National Gas Access Regime |
| IRSR | Inter Regional Settlement Residue |
| kVA | kilo Volt-ampere |
| kW | kilowatt |
| KWh | kilowatt hour |
| LRMC | Long Run Marginal Cost |
| MAR | Maximum Allowed Revenue |
| MCE | Ministerial Council on Energy |
| MEU | Major Energy Users Inc |
| MNSP | Market Network Service Provider |
| mVA | mega Volt-ampere |
| MW | Megawatt |
| MWh | Megawatt hour |
| NEL | National Electricity Law |
| NEM | National Electricity Market |
| NEMMCO | National Electricity Market Management Company |
| NER | National Electricity Rules |
| NGF | National Generators Forum |

| | |
|---|---|
| ORC | Optimised Replacement Cost |
| PC | Productivity Commission |
| PIAC | Public Interest Advocacy Centre |
| PTRM | Post Tax Revenue Model |
| RAB | Regulatory Asset Base |
| Rules | National Electricity Rules |
| SRA | Settlement Residue Auction |
| SRMC | Short Run Marginal Cost |
| TNO | Transmission Network Owner |
| TNSP | Transmission Network Service Provider |
| TUoS | Transmission Use of System |

## Overview of the Draft Rule

In the context of the current reforms to the regulation of the national energy market, the Australian Energy Market Commission (the Commission) has been required to conduct a review of the revenue and pricing rules to apply to the regulation of electricity transmission network services (the Review).[3] This Draft Determination presents the Commission's reasons for its Draft Pricing Rule, which is the third stage of the Review, following the recent release of its Draft Revenue Rule.[4]

Transmission pricing methodology is fundamentally concerned with the question of 'who should pay how much' in order to recover the costs of providing Prescribed Transmission Services.[5] The determination of who pays and the amount they pay has implications for the achievement of the National Energy Market (NEM) Objective, particularly as it relates to promoting the efficient use of transmission services and investment by electricity consumers and producers.

In developing the Draft Pricing Rule, the Commission has undertaken an extensive public consultation process that included the issuing of an Initial Scoping Paper, a Transmission Pricing Issues Paper and a Proposed Pricing Rule Report. The Commission has received and considered submissions from stakeholders in response to these papers.

Having considered submissions and conducted its own analysis, the Commission has reached the view that approach adopted in the Proposed Pricing Rule is broadly appropriate. That is, at this stage, the Commission does not consider that there is a need to alter the substance of the current approach to pricing for Prescribed Transmission Services to a large extent. However, as previously stated in the Rule Proposal Report this view is conditional on the outcomes of the other reviews currently being undertaken. In particular, the Congestion Management Review (CMR) may have implications for the appropriateness of the current broad allocation of Prescribed Transmission Services costs to electricity consumers.

---

[3] The requirement is specified in Section 35(1) of the National Electricity Law.

[4] Draft National Electricity Amendment (Economic Regulation of Transmission Services) Rule 2006.

[5] A Prescribed Transmission Service is any of the following services:

(a) *shared transmission services* that meet (but do not exceed) the *network* performance requirements (both as to quality and quantity) (if any) which those *shared transmission services* are required to meet under any *jurisdictional electricity legislation*; and

(b) *shared transmission services* that meet (but do not exceed) the *network* performance requirements (both as to quality and quantity) set out in schedule 5.1a or 5.1, except to the extent that the *network* performance requirements which those *shared transmission services* are required to meet are prescribed under any *jurisdictional electricity legislation*; and

(c) services that are required by *NEMMCO* to be provided under the *Rules*, that are necessary to ensure the integrity of a *transmission network*, including through the maintenance of *power system security* and assisting in the planning of the *power system*; and

(d) *connection services* that are provided by one *Network Service Provider* to serve another *Network Service Provider*,
but does not include negotiated transmission services or market network services.

Submissions generally supported the approach taken in the Proposed Pricing Rules of shifting to a principles-based regulatory framework where the implementation elements of the regime are left to the guided discretion of TNSPs and the AER. This largely confirms the continuation of current pricing practices while providing scope for pricing innovations to be proposed in accordance with principles in the Rules. This rebalancing of the rules for pricing is consistent with the approach adopted by the Commission in the Draft Revenue Rule.

In addition to developing a principles-based regulatory framework the Commission has considered stakeholder submissions on other issues raised in the Rule Proposal Report such as whether discounts to particular directly-connected consumers should be permitted, the treatment of TUoS rebates and inter-regional TUoS arrangements.

The remainder of this overview provides a summary of the key elements of the Commission's Draft Pricing Rule and identifies areas where the Commission is seeking particular comment.

## Promotion of the NEM Objective

The Commission's Draft Rule for the regulation of transmission pricing seeks to promote the NEM Objective. The NEM Objective is focused on the provision of efficient, reliable and safe electricity services for the long term interests of consumers. The Commission believes that the NEM Objective is founded on the concept of serving the long term interests of consumers through the promotion of economic efficiency in the provision, use of, and investment in, electricity services. Efficiency refers to the maximisation of the total value consumers and producers jointly obtain from the market. In the context of this Draft Rule, the Commission considers that the rules for transmission pricing should also promote good regulatory practice by enhancing:

- Stability and predictability – that is, transmission prices should be stable and predictable enough to enable market participants to make long term decisions; and

- Transparency – the process for setting prices should be as transparent as practicable to give participants confidence that pricing outcomes will be consistent with the NEM Objective and the Rules.

To achieve these aims the Commission has sought to develop a robust regulatory framework for transmission pricing consistent with the approach taken for transmission revenue. Such a framework requires the Rules to provide appropriate signals to avoid either under or over investment, address the potential for network operators to exercise market power and enhance transparency and predictability of the regulatory arrangements and approach.

The Commission considers that these outcomes can be best achieved by:

- clarifying the link between the prices paid by electricity consumers and producers to transmission costs ;
- permitting the recovery of the efficient costs of transmission service provision, including 'sunk costs'[6];
- encouraging transmission prices to provide efficient locational and investment signals to participants; and
- ensuring the pricing rules take account of other aspects of the NEM arrangements, such as transmission investment regulatory arrangements, in order to avoid inefficient 'oversignalling' of the value or cost of transmission.

## Key transmission pricing issues

The Proposed Pricing Rule sought to substantially maintain and clarify the current approach to pricing in the Rules while also clarifying the approach in a number of areas. On this basis, the Commission determined that:

- generators should pay the costs directly resulting from their connection decisions, that is, 'shallow connection';
- it is not appropriate at this stage for generators to contribute towards the costs of the shared network through prescribed generator TUoS charges;
- CRNP[7] and modified CRNP[8] are appropriate locational pricing methodologies, however, there should be scope for these to be developed further into the future; and
- To some extent price structures should be specified in the Rules.

In response to submissions the Commission has decided to largely maintain the current approach to these key transmission pricing issues. However, as stated in the Rule Proposal Report this position is conditional on the outcomes of other reviews underway. In particular, the Commission notes that the outcomes of the Congestion Management Review (CMR) may affect its present position on these matters.

---

[6] Sunk costs refer to those costs that would not be recovered if the decision that caused those costs to be incurred were reversed.

[7] Cost Reflective Network Pricing (CRNP) is defined in the Rules as "A cost allocation method which reflects the value of assets used to provide *transmission* or *distribution* services to *Network Users*". It is described in Schedule 6.4 of the existing Rules. Both CRNP and modified CRNP have also been given new definitions in the Proposed Rule.

[8] Modified CRNP is described in Schedule 6.4 of the existing Rules.

## Framework for regulation of transmission pricing for Prescribed Transmission Services

The Commission developed a principles-based approach for transmission pricing regulation in the Proposed Pricing Rule. Based on views in submissions the Commission has largely maintained this approach for the Draft Pricing Rule. The Commission considers that this approach ensures the key design features of the regulatory regime for pricing remain in the Rules while providing for implementation and administration issues to be left to the guided discretion of the AER and the TNSPs. The Commission considers that this approach provides transparency and certainty and is also consistent with the approach taken for transmission revenue.

The Commission also considered that the principles-based approach should be supported by clear procedural arrangements incorporating the assessment of pricing methodologies by the AER in accordance with principles in the Rules. The Proposed Pricing Rule also allowed the AER to develop guidelines in specific areas to promote more certainty and clarity over the implementation of the pricing arrangements for TNSPs and their customers.

While submissions were generally supportive of the development of an open and transparent process for determining a TNSP's pricing methodology, submissions did raise concerns, however, that the opportunity for the AER to develop guidelines on CRNP, the definition and applications of defined terms and the types of transmission assets that the pricing rules apply to may not add additional clarity and certainty. The Commission agrees with submissions that the Rules provide sufficient clarity regarding these issues and that the development of guidelines on them is not likely to provide significant benefit. Therefore, the Commission has removed the option to develop guidelines on these issues from the Rules.

## The Commission's Proposed Pricing Principles for Prescribed Transmission Services

In developing the principles to be codified in the pricing rules for Prescribed Transmission Services, the Commission sought to confirm the fundamental role of the causer pays principle in providing signals for efficient economic decision-making. On that basis the Commission adopted the concept of costs that are 'directly attributable (on a causation basis)' to capture this intent. The allocation of asset costs to Prescribed Transmission Services in this manner results in the annual service revenue requirement for each category of prescribed services (ASRR). The Pricing Proposed Rule also outlined principles for allocating the ASRR further amongst network user connection points and for price structures.

Submissions raised a number of important issues in relation to the Proposed Rule, including:

- the approach of making 'up front' adjustments to the MAR to obtain the AARR;
- the practicalities of a causation-based cost allocation approach; and
- the priority ordering approach

In considering these issues further the Commission does not consider that substantial change is required from the approach taken in the Proposed Rule. However, the Commission does consider that there is some merit in making some adjustments to rules in this regard.

The Commission has made amendments for the Draft Pricing Rule to ensure that the cost allocation process for existing transmission assets is consistent with the arrangements under the Draft Revenue Rule. In order to promote consistency in the means of allocating costs of prescribed services and the means of determining whether future assets are attributed between prescribed or negotiated the Commission has decided that:

- assets in existence as at 24 August 2006 should be attributed to prescribed service categories on a directly attributable (i.e. causation) basis taking existing generation and load as given; and

- where the 'cause' of a transmission asset is determined to be an entry service and where that entry service is not subject to an agreement that specifies price, the Negotiated Transmission Services arrangements for price should apply.

The Commission considers that this approach, while ensuring consistency with the approach taken for transmission revenue, also addresses some of the practical difficulties raised in submissions regarding the test for causation.

The Commission has also proposed changes to the priority ordering approach for the allocation of expenses or costs which are attributable to a number of transmission services compared to the Proposed Pricing Rule. The Commission considers that it would be appropriate to rearrange the priority ordering so that where an asset or expense is directly attributable to the provision of several services, the attendant costs should be allocated:

- First to prescribed transmission use of system services, to the extent that the asset cost (on a standalone basis) is directly attributable to the provision of use of system services;

- Second to (prescribed) common services to the extent that the asset cost (on a standalone basis) is directly attributable to the provision of common services; and

- Third, to prescribed entry/exit services.

The Commission considers that this approach promotes consistency considering that under the revenue rules the costs attributed to Negotiated Transmission Services are effectively those that cannot justifiably be attributed to Prescribed Transmission Services (i.e. TUoS services or common services). Therefore, the Commission considers that where an asset or expense is directly attributable to several services, the first allocation of the costs should be to TUoS and common services.

## Prudent Discounts

In the Proposed Rule Report the Commission supported the views in submissions that a prudent discounts regime should continue. The Commission also proposed the following additions for the regime:

- elevating the AER Guidelines to the Rules;
- allowing (but not obliging) a TNSP to seek 'up-front' approval of a discount from the AER and for such an approval to remain effective for the duration of the TNSP's agreement with the relevant Transmission Customer; and
- providing a process to be followed by the AER in dealing with the up-front application for a prudent discount.

Submissions generally supported the approach in relation to prudent discounts taken for the Pricing Proposed Rule. Therefore, the Commission has maintained its approach in the Draft Rule in recognition of the benefits of improving the degree of certainty and transparency of the regulatory framework for prudent discounts, particularly in view of the long term nature of many transmission service agreements.

However, a number of submissions were concerned that the incentives were not strong enough to encourage TNSPs to negotiate prudent discounts with customers. The Commission considers that insufficient evidence has been provided at this stage to suggest a stronger requirement to negotiate is needed for TNSPs. It also notes that the commercial stranding incentive to negotiate prudent discounts included in the Draft Revenue Rules addresses this issue and remains to be implemented and tested.

## TUoS rebates to embedded generators

In the Pricing Proposed Rule the Commission sought stakeholder views on whether some conditions on the existing regime TUoS rebates to embedded generators should be implemented. In particular, the Commission sought stakeholder feedback on three options that have arisen out of the consultation process:

- that TUoS rebates apply to generators up to 10 MW in capacity while larger generators remain eligible for network support payments; or
- that a minimum threshold be defined to account for the reasonable costs of administering the TUoS rebate; or
- maintain the existing arrangements but require any network support payments to an embedded generator reflect the expected TUoS rebates they would receive.

Submissions generally supported the Commission's first option in relation to TUoS rebates for embedded generators. In addition, there was support for requiring network support payments to be net of any expected TUoS rebate. The rationale for this approach is that TUoS rebates should only be available for embedded generators where they represent the best option for meeting load. However, the Commission has formed the view that a comprehensive change to the regime of this nature is not within the scope of the transmission pricing rules because embedded generators mainly interact with distribution businesses rather than transmission businesses. The Commission remains of the view that this is a matter that participants and policy makers should consider further. Therefore, the Commission intends to bring these issues to the attention of the MCE in the context of its current review of the distribution network rules.

## Inter-regional TUoS arrangements

The Commission recognised in the Rule Proposal Report that the limited effectiveness of the inter-regional TUoS arrangements may reduce the efficiency of the transmission prices applied in the NEM. The Commission, therefore, sought further submissions on other potential approaches for the treatment of inter-regional TUoS.

In response, submissions indicated to the Commission that the current arrangements are inadequate and do not provide appropriate signals to TNSPs or consumers. However, submissions also were of the view, which the Commission has accepted, that the inter-regional TUoS arrangements are a policy matter that requires input from the MCE. Therefore, recognising the inter-jurisdictional nature of the issue, as well as its complexity, the Commission has decided that it write to the MCE expressing the view that a further review of the issues is needed.

## Pricing for negotiated transmission services

The Commission sought comment from stakeholders regarding whether the model for commercial dispute resolution for price for Negotiated Transmission Services should be extended to permit consideration of the terms and conditions of the connection agreements under which those prices are charged, and to which the price is inextricably linked.

Submissions were generally in favour of an extension of the commercial dispute resolution model to permit consideration of the terms and conditions of the connection agreements under which prices for Negotiated Transmission Services are charged. However, the Commission was not provided with compelling evidence to suggest that the parties involved in agreements for Negotiated Transmission Services were not capable of reaching appropriate outcomes in the absence an extension to the commercial arbitration regime to the terms and conditions. On this basis, the Commission does not see a need to further extend the commercial arbitration regime at this stage.

# 1 Introduction to the Draft Determination

In the context of the current reforms to the regulation of the national energy market, the Australian Energy Market Commission (the Commission) has been required to conduct a review of the revenue and pricing Rules (the Review) to apply to the regulation of electricity transmission network services.[9] The matters required to be reviewed are specified in items 15 to 24 of Schedule 1 of the National Electricity Law (see Appendix 1) and include, amongst other matters:

- the regulation of transmission revenues (item 15); and
- the regulation of transmission prices (item 16).

Due to the complex nature of the review task, the Commission decided to undertake the Review in two stages:

- First, the Commission has been reviewing the existing Rules applicable to the regulation of transmission revenue earned by TNSPs, and recently released a Draft Revenue Rule for further consultation.
- Second, the Commission has been reviewing the existing Rules to apply to the pricing of Prescribed Transmission Services by TNSPs. This report presents the Commission's rationale for its Proposed Pricing Rule.

There are important and strong linkages between the rules relating to the regulation of transmission revenues and pricing. At a high level, revenue rules seek to provide, in the absence of direct competitive pressures on TNSPs:

- incentives for the efficient investment in, and provision of, transmission services; and
- constraints on the aggregate revenues TNSPs can earn from their customers from the provision of Prescribed Transmission Services.

Pricing rules seek to ensure prices provide incentives for the efficient use of the various transmission services. They do this by providing signals for efficient electricity consumption and production decisions, as well as efficient investment decisions by actual and potential network users.

In considering its Proposed Pricing Rule, the Commission has been mindful of the interactions between the revenue and pricing rules, and has endeavoured to design an overall effective regulatory framework for electricity transmission regulation.

---

[9] The requirement is specified in Section 35(1) of the National Electricity Law.

## 1.1 The Commission's Approach

To develop its Proposed Pricing Rule, the Commission has undertaken an extensive investigation and public consultation process. This involved the release of:

- an initial Scoping Paper in July 2005, which identified various issues that the Commission believed to be important to these reviews, and invited submissions from stakeholders on the issues raised;
- a Pricing Issues Paper in November 2005, which presented the Commission's further analysis of the pricing issues identified earlier and raised in submissions to the Scoping Paper, and inviting further submissions; and
- a Pricing Proposal Report and Proposed Pricing Rule, which presented the Commission's proposals for the Rules stemming from issues that were raised in the previous consultations. The Commission sought feedback on the Proposed Pricing Rule from interested stakeholders.

The Commission has carefully considered stakeholder submissions made in response to these papers in developing the Draft Pricing Rule (see listing in Appendix 2). The Commission has also taken into consideration the views and discussion raised during the development of the Draft Revenue Rule, which was released on 27 July 2006.

Another relevant consideration for the Review has been the wider debate on regulation in the energy market as reflected in recent reports by the Productivity Commission[10] and the Ministerial Council on Energy's Expert Panel[11].

In forming its views on the Proposed Pricing Rule, the Commission is also required to satisfy a number of legislative requirements including:

- meeting minimum content requirements for a Rule Proposal[12];
- ensuring the Rule Proposal satisfies the NEM Objective[13] and Rule-making test[14]; and
- ensuring the Proposed Rule is within the AEMC's Rule making powers.

The Commission is satisfied that it has met these requirements and additional details on how these requirements have been met are provided in this Draft Determination.

The publication of the Draft Pricing Rule is accompanied by this Draft Determination, which provides the Commission's reasons for its decisions and represents the

---

[10] Productivity Commission, *Review of the National Access Regime*, Report no. 17, 2001, AusInfo, Canberra

[11] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, 2006.

[12] Clause 8, National Electricity Regulation

[13] Section 7, NEL

[14] Section 88, NEL

commencement of the formal Rule change process for the transmission pricing component of the Review.

The next stages for the transmission pricing component of the Review are as follows:

- submissions on the Draft Pricing Rule and this Draft Determination close on 30 November 2006; and
- release of a Final Pricing Rule by 1 January 2007.

## 1.2 The Role of the NEM Objective

The National Energy Market (NEM) Objective requires the Commission to consider the promotion of efficient investment in, and use of, electricity services, when considering or developing Rule Proposals. Economic efficiency is commonly defined as having three elements and in the context of considering transmission pricing rules, these are:

- productive efficiency – means the electricity system is operated on a 'least cost' basis given existing infrastructure and the status of the network. For example, generators should be dispatched in a manner that minimises the total system costs of meeting consumers' demands;
- allocative efficiency – means electricity production and consumption decisions are based on prices that reflect the opportunity cost of the available resources; and
- dynamic efficiency – means maximising ongoing productive and allocative efficiency over time, and is commonly linked to the promotion of efficient longer term investment decisions.

Further, the Commission has taken the view that the NEM Objective is not solely focussed on a technical approach to the promotion of efficiency. Rather, the NEM Objective has implications for the *means* by which regulatory arrangements operate as well as their intended *ends*. This means that the Rules for transmission pricing should also promote:

- stability and predictability – other things being equal, transmission prices should be sufficiently stable and predictable to enable participants to plan and make long term decisions without suffering price shocks; and
- transparency – the price-setting process should be as transparent as practicable so that participants retain confidence in the regulatory arrangements and are able to make locational and consumption decisions on an informed basis.

These requirements are founded in the good regulatory practice design principle, which the Commission believes is central to its task in furthering the NEM Objective.

In the Issues Paper, the Commission asked whether the NEM Objective should also encompass distributional concerns as well as economic efficiency, and if so, how these distributional concerns should be taken into account.

Submissions on the Issues Paper were divided as to whether distributional concerns were an appropriate consideration for the application of the NEM Objective to transmission pricing. Several considered that economic efficiency should be the sole focus of the Rules.[15] Others were satisfied that efficiency should be the key focus, while favouring the inclusion of options for minimising price shocks and radical rebalancing of transmission tariffs across geographic areas as part of that focus.[16] However, some stakeholders, including PIAC[17], considered that implications for consumer welfare should be an important criterion for developing pricing arrangements.

Some submissions on the Rule Proposal also addressed this issue.

PIAC argued that the NEM objective requires Rule change proponents to demonstrate through detailed arguments how a change furthers the long term interests of consumers rather than just making simple assertions about gains in efficiency or changes in the investment environment.[18]

MEU considered that the Commission focussed on the interests of TNSPs and generators and failed to clearly demonstrate how its Rule Proposal would promote the interests of consumers.[19]

The Commission considers that the NEM Objective is primarily concerned with efficiency and good regulatory practice. These qualities will help ensure that the arrangements will benefit consumers in the long run. Rather than seeing distributional outcomes as a distinct limb or component of the NEM Objective, the Commission has taken the view that distributional outcomes have relevance in so far as they may negatively influence the stability and integrity of the pricing arrangements. Therefore, the Commission proposes to maintain or adopt measures that limit the extent of price shocks for transmission network users. However, basing fundamental decisions such as who pays how much primarily on distributional criteria rather than efficiency and good regulatory practice is likely to be counter-productive to the interests of consumers in the long run.

## 1.3 Structure of the Report

The remainder of this Draft Determination is structured as follows:

- chapter 2 outlines the Commission's framework and approach in developing the proposed pricing rules, providing an overview of the Commission's rationale;
- chapter 3 discusses the Commission's views on a number of specific issues relating to the pricing rules, and provides a detailed rationale for the Commission's present intention to not fundamentally change the existing pricing arrangements in the Draft Pricing Rule;

---

[15] AGL, 20 January 2006, p.A-1; MEU, December 2005, p.19; QR, 9 January 2006, pp.2-4.

[16] ETNOF, December 2005, p.5; UED, December 2005, pp.5-6.

[17] Public Interest Advocacy Centre, 6 January 2006, pp.1-2.

[18] Public Interest Advocacy Centre, 26 September 2006, p.1.

[19] Major Energy Users, September 2006, pp.7-9.

- chapter 4 provides details of the Commission’s principles based approach in the Draft Pricing Rule;
- chapter 5 specifies the Commission’s approach to the process by which the Draft Pricing Rule is implemented, including the role of the AER in approving pricing methodologies proposed by TNSPs;
- chapter 6 discusses prudent discounts;
- chapter 7 discusses TUoS rebates to embedded generators;
- chapter 8 discusses inter-regional TUoS arrangements;
- chapter 9 considers issues relating to pricing for Negotiated Transmission Services;
- In addition:
    - Appendix 1 reproduces Schedule 1, items 15-24, of the NEL;
    - Appendix 2 provides a list of stakeholders who made submissions to the Pricing Issues Paper; and
    - Appendix 3 provides a timeline for the transmission review process.

# 2 Framework and approach for the Proposed Pricing Rule

In the Draft Revenue Rule, the Commission specified a full revenue cap methodology that enables the recovery of efficient costs while managing TNSPs' potential for exercising market power. Matters of implementation detail were left to the guided discretion of the AER and TNSPs. In light of the proposed revenue regime, the Commission considers that a principles-based approach to pricing, supported by procedural requirements in the Rules, is appropriate. This means that TNSPs would be responsible for the implementation and administration of pricing methodologies in accordance with the Rules. The role of the regulator would be to assess the pricing methodology against the principles and to monitor pricing outcomes.

The aim of this chapter is to outline the rationale of the Commission for the approach it has taken and its response to submissions to the Proposed Pricing Rule.

This chapter is structured as follows:

- section 2.1 discusses a number of matters relating to the role of transmission pricing in the NEM. These are:
  - the importance of transmission pricing in providing signals to actual and potential network users;
  - issues arising in the setting of transmission prices to promote the NEM Objective; and
  - in light of the above matters, the need for regulation of pricing methodologies for Prescribed Transmission Services;
- section 2.2 provides an overview of the recent debate on pricing issues in the context of infrastructure regulation, particularly the views of the Productivity Commission in its review of the National Access Regime[20] and the recent report by the Ministerial Council on Energy's Expert Panel on Energy Access Pricing[21];
- section 2.3 briefly outlines the approach to transmission pricing contained in the existing Rules as the basis for considering the rationale underpinning the Commission's decisions regarding its proposed approach to transmission pricing; and
- section 2.4 explains the approach in the Proposed Pricing Rule and an overview of the Commission's response to submissions on the proposed approach on the following areas:

---

[20] Productivity Commission, *Review of the National Access Regime*, Report no. 17, 2001, AusInfo, Canberra.

[21] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, 2006.

- that existing pricing practices are broadly appropriate and should continue to be permitted;
- the principles-based regulatory framework; and
- the proposed procedural framework for approving TNSPs' proposed pricing methodologies.

## 2.1 Role of regulation for transmission prices

This section examines the role and significance of transmission pricing in promoting efficiency in the provision and use of electricity services. It also considers some of the key implications that transmission pricing has for the efficiency of the overall market.

### 2.1.1 The importance of transmission pricing

The Commission is required to ensure that the Rules are consistent with the NEM Objective, which is to promote the efficient investment in, and use of, electricity services for the long-term interests of consumers. The approach to regulating transmission prices and the resultant transmission prices can have a significant impact on the promotion of the NEM Objective in two fundamental ways.

First, because transmission prices determine how TNSPs' regulated revenues are recovered, they impact on the incentives faced by TNSPs to invest in transmission infrastructure.[22] If a TNSP is unable to recover the efficient cost of service provision through prices charged, there is little incentive to invest in maintenance or the expansion of operations, even when it is in the long term interests of consumers to do so.

Second, transmission prices provide signals to the electricity market, which influence the decisions of actual and/or potential electricity consumers and producers. On the demand side, because transmission prices directly affect the delivered electricity price paid by end users at a particular location, they may impact consumption decisions as well as locational investment decisions. Excessively high transmission charges could, for example, result in inefficient by-pass of the transmission network by new or existing consumers. On the supply side, transmission prices can influence both the timing and quantity of electricity production decisions as well as locational investment decisions by electricity generators. This includes investment by embedded generators, inset networks and alternative energy sources.

[22] This means that the regulatory approach to transmission pricing should ensure that all efficient costs are recovered. The lack of a reasonable expectation that a TNSP will recover its efficient costs will significantly affect the incentives faced by TNSPs to invest in its infrastructure.

### 2.1.2 Issues in the setting of transmission prices

In addition to the broader issues outlined above, there are a number of specific issues regarding transmission pricing methodologies that may impact on the promotion of the NEM Objective. These include:

- the basis for charging;
- the approach to sunk cost recovery;
- the need to provide efficient longer term locational and investment signals; and
- the need to take account of other aspects of transmission regulation.

These issues are discussed below.

### 2.1.3 Basis for charging

Transmission pricing fundamentally involves consideration of 'who should pay how much' for transmission services. This requires an understanding of the drivers of costs and their links to services provided to network users and classes of users.

In order to promote allocative efficiency[23], transmission prices should be set on a 'causer pays' basis where possible. This means that where transmission costs are incurred following a direct request by (or agreement with) a particular network user or users, those user(s) should be required to pay the relevant costs. This is effectively a restatement of the marginal cost pricing principle – where prices equal the marginal or incremental costs of a network user's decision, network users will tend to make efficient decisions. This is because they will have incentives to use transmission services up to the point where their incremental benefits from use equal the incremental costs of provision.

In practice, however, it may not be possible to allocate transmission costs to individual network users solely on the basis of causation. This is especially the case for costs associated with the shared meshed network, which exhibits strong externalities (both positive and negative) associated with transmission use and relatively high transactions costs for internalising these externalities. In these circumstances, the causal link between *individual* network users' decisions and the incurring of transmission costs may not be clear.

However, the causer pays principle may at least guide whether, in general, consumers or producers of electricity should contribute towards the recovery of particular costs. This is because the majority of transmission investment in the shared meshed network

---

[23] Allocative efficiency is a dimension element of economic efficiency and describes the benefits associated with linking costs to prices such that appropriate provision and use of services occurs. For example, if the price of a particular service is higher than the cost of providing the service, then, all other things being equal, there is likely to be higher than efficient provision and lower than efficient use of that particular service. Allocative efficiency benefits can therefore accrue by linking prices to incremental costs.

is undertaken to meet the reliability obligations imposed to satisfy the requirements of consumers. Therefore, the Commission is of the view that the causer pays principle is a useful starting point for linking transmission costs to the respective prices paid by consumers and producers of electricity.

The causer pays principle, however, may also be difficult to apply when costs are incurred to serve multiple purposes; in other words, where there are several cost drivers. Such costs typically arise where economies of scale and scope exist: that is, situations where it is cheaper in an overall sense to provide services jointly rather than separately. In these cases, it is important to ensure that prices for each of the relevant services lie between the incremental and the standalone costs of providing each service. These requirements are known as the Baumol-Willig conditions.

An alternative basis for setting transmission prices is to apply the 'beneficiary pays' principle. The Commission, however, considers that the use of a 'beneficiary pays' principle for allocating network costs would not contribute to the NEM Objective in the same way as the 'causer pays' approach. This is because although in many cases the causers and beneficiaries of a given service cost are the same, the party that benefits from a particular transmission investment may not be the party whose requests or actions directly cause that investment to occur. In addition, the beneficiary of a Prescribed Transmission Service may change over time as network conditions change, whereas the causer of a service involves a once-and-for-all judgment that is likely to result in consistent implementation. The Commission notes that in work undertaken by NECA in 2002 on the development of a 'beneficiary pays' method for the allocation of new network investment costs, NECA was not able to satisfactorily address these issues.[24]

### 2.1.4 Sunk cost recovery

Economic theory and competitive market experience demonstrate that economic efficiency, particularly allocative efficiency, is enhanced when prices are equal to the marginal (or incremental) cost of providing the relevant good or service. A key feature of services provided by infrastructure such as transmission networks is that if prices are set equal to marginal or incremental cost, a TNSP may be unable to recover its fixed capital investments.[25] A relevant issue in designing the transmission pricing regulatory framework is therefore how best to recover these historical expenditures while minimising disincentives to the use of existing infrastructure. In other words, the regime needs to balance allocative efficiency considerations with the need to enable recovery of efficient costs and provide enduring incentives for capital investment.

At the same time, in its submission to the Rule Proposal Report, the MEU contended that a revenue cap approach with little scope for optimisation of redundant assets means the TNSPs may recover in excess of efficient costs (pp.10 and 13). While this

[24] The Commission notes that NECA's deliberations did not proceed beyond the publication of an Issues Paper: NECA, *Beneficiary Pays: A Framework for Implementation, Issues Paper*, March 2002 (available at: www.neca.com.au).

[25] Unless the reliability of service provision is allowed to degrade to levels below current requirements.

may be the case, the inefficiency of this outcome can be limited by the way in which the fixed (if excessive) costs are recovered.

As has been previously noted by the Commission,[26] one approach to the recovery of sunk costs that seeks to minimise disincentives to the use of existing infrastructure is a two-part tariff. A two-part tariff refers to a tariff structure where fixed capital costs are recovered through a fixed charge component, while any immediate (short run) marginal costs of service provision are recovered through a variable charge component. This approach can serve to minimise potential distortions in the use of the transmission network because once the fixed fee is paid, decisions on service use relate entirely to the variable cost component. As this component is based on the marginal cost of service, consumption and production decisions should be consistent with efficient outcomes.

An alternative approach to using a two-part tariff is to set charges on the basis of Ramsay pricing principles. Ramsay pricing principles allocate sunk costs on the basis of relative willingness to pay between users of the particular services. While Ramsay pricing, in theory, provides correct signals to maximise efficiency in the use of infrastructure, it is rarely applied in practice because of the enormous informational requirements necessary to estimate individual customers' willingness to pay.

### 2.1.5 Transmission prices should provide efficient locational and investment signals to participants

A further consideration is the locational and investment signals provided to participants through transmission prices. The difficulty is that transmission prices can be orientated to maximise the use of the existing network, but this may conflict with minimising the cost of providing transmission services in the longer term.

For example, if the price for transmission use is based on the short run marginal cost (SRMC) of transmission, this may encourage consumers to locate far from generation sources so long as spare transmission capacity exists. This scenario may particularly arise if transmission capacity is augmented according to non-market criteria (such as deterministic reliability standards) and through centralised processes (such as the Regulatory Test). Given these other arrangements, it might be more appropriate for transmission prices to seek to approximate the long run marginal cost (LRMC) of providing transmission services. Such prices should reflect the need for, and cost of, transmission augmentation at a particular location in the future. This should work to deter potential consumers (loads) from locating in areas that will require later costly augmentation.

However, the use of LRMC-based prices instead of SRMC-based prices may cause inefficient under-utilisation of spare transmission capacity in some cases. For example, a smelter located adjacent to a generator may have incentives to physically by-pass the regulated transmission network if it is charged a price that exceeds the immediate incremental cost of its network usage. Therefore, in cases where prices based on some estimate of LRMC are likely to lead to inefficient by-pass of the existing network,

---

[26] AEMC, Review of Transmission Revenue and Pricing Rules, Transmission Pricing: Issues Paper, November 2005, p.60.

flexibility in the pricing regime to allow discounting or negotiation should be available to avoid such outcomes.

### 2.1.6 Transmission prices should take account of other aspects of the NEM arrangements

When considering the regulatory framework for transmission pricing, it is also necessary to be aware of any interactions with other aspects of the NEM regulatory arrangements, particularly how they impact on the achievement of the NEM Objective.

The elements of the regulatory framework that the Commission has taken into consideration when developing the pricing rules include:

- regional treatment of transmission losses and congestion;
- non-firm generator access to the market; and
- transmission investment regulatory arrangements (including in the Draft Revenue Rule and the Regulatory Test).

Some of these interactions were referred to above in the discussion of efficient locational signals to transmission network uses and potential users.

While these elements of the regulatory framework are not the subject of the current Review, the Commission is examining these through separate processes (for example, the CMR is dealing with transmission congestion). The Commission has taken care to ensure that the Draft Pricing Rule it has developed would not result in inefficient 'oversignalling' of the value or cost of transmission, given the signals resulting from other aspects of the NEM regulatory arrangements. However, this issue would need to be revisited if substantial changes to the other arrangements emerged from the CMR or other reviews.

### 2.1.7 Need for regulation

The Commission's regulatory framework as outlined in the Draft Revenue Rule explicitly implements a CPI-X revenue cap form of control to Prescribed Transmission Services, through the application of a building blocks methodology. This regulatory approach has been adopted in recognition of the natural monopoly characteristics of transmission service provision and the resulting need to manage the potential for TNSPs to exercise market power. The revenue cap form of regulation enables TNSPs to recover the efficient costs of providing network services and also embodies incentives for efficient expenditure and service provision on the part of TNSPs. Given these constraints provided by the regulatory framework for revenue, the Commission has examined the need for specific regulatory guidance on pricing.

The two key *form of control* options for implementing a revenue cap *form of regulation* are:

- price cap – in which prices are capped but not revenues; and
- revenue cap – in which revenues are directly capped.

In general, a *price cap* form of control provides TNSPs with some incentive to set prices in a way that promotes the efficient use of the *existing* network.

This is because under a price cap form of control, increasing the utilisation of a TNSP's network may result in larger gross revenues than a lower level of utilisation. Assuming TNSPs' costs of service are largely fixed, TNSPs would generally find it profitable to set prices in a way that encouraged network utilisation. Further, given that at least the physical infrastructure costs of the existing network are fixed and sunk, such prices are likely to enhance productive and allocative efficiency. However, while price caps create this incentive to promote efficient use of the network in the short run, they do not necessarily promote efficiency in the longer run. This is because prices set in this manner may not take into account the cost of future network investment to meet higher levels of consumption and production at different locations in the grid.

By contrast, a *revenue cap* form of price control provides less incentive for a TNSP to maximise network utilisation in the short run. This is because a revenue cap allows for any under-recovery of allowable revenue by a TNSP in one year to be recovered in subsequent years. This provides benefits through greater revenue certainty for transmission businesses, which is important considering they incur costs that are largely fixed and have little capacity to influence final demand. If a revenue cap is accompanied with low risk of regulatory stranding of redundant assets, TNSPs will have relatively weak incentives to set prices to promote high network utilisation as a means of reducing the risk of redundancy.[27] If anything, under a revenue cap form of control, TNSPs have an incentive to formulate prices in a manner that is as mechanical and non-controversial as possible, in order to avoid payment disputes with their customers.

This discussion highlights that in the absence of pricing rules, regardless of the form of control adopted, a revenue cap form of regulation provides weak incentives for TNSPs to price services in a way that promotes the NEM Objective. Indeed, all 13 submissions received by the Commission in response to the question on the need for price regulation considered that some form of price regulation was required. In view of the importance of transmission prices for efficient utilisation and investment in both the network and electricity markets, and the weak commercial incentives of TNSPs to price efficiently, the NEM Objective is likely to be best served by some form of regulatory oversight of transmission pricing.

## 2.2 Recent debate on pricing regulation

During the course of the Commission's review of transmission pricing rules, there has been ongoing public policy debate on a range of issues relating to the regulation of infrastructure in Australia. This has led to the publication of a number of reports relevant to the Commission's review including, amongst others:

---

[27] On balance, as discussed in the Draft Determination on revenue, the Commission still believes that the relative advantages of a revenue cap form of control means that it is preferable to a price cap form of control.

- the Productivity Commission's Review of the National Access Regime;[28]
- the Productivity Commission's Review of the Gas Code;[29] and
- the Ministerial Council on Energy's Expert Panel Review of Energy Access Pricing.[30]

The Productivity Commission's (PC) Review of the National Access Regime considered the relevant pricing principles to apply to Part IIIA of the *Trade Practices Act* 1974. Regarding the level of prices, the PC recommended that prices for all services provided by an access provider should generate revenues that are at least sufficient to meet the efficient long-run costs of providing access, and include a return commensurate with the commercial and regulatory risks involved. In addition, the PC indicated that prices should at least cover the incremental cost of infrastructure service provision[31]. The PC, in its Review of the Gas Access Regime considered there would be benefits in making the reference tariff principles in the Gas Code consistent with the pricing principles that were agreed for the national access regime[32].

Regarding the structure of prices, the PC expressed a view in favour of allowing multi-part pricing and price discrimination where it aids efficiency. The PC also recommended that vertically integrated service providers should not discriminate in favour of its downstream operations unless this can be justified on the basis of cost.

The Expert Panel delivered its report on energy access pricing to the MCE in April 2006. The Expert Panel's report made a number of observations on the appropriate principles for price-setting. The report noted that network prices ought to consider allocative efficiency as well as productive and dynamic efficiency[33]. Importantly, the report recognised that there may be trade-offs in using prices to promote different dimensions of efficiency and that it is necessary to consider the optimal balance of incentives for the achievement of the various aspects of efficiency. For example, prices that promote operational cost efficiencies (productive efficiency) may not maximise allocative efficiency (because under traditional incentive regulation, prices are allowed to exceed actual costs).

---

[28] Productivity Commission, *Review of the National Access Regime*, Report no. 17, 2001, AusInfo, Canberra.

[29] Productivity Commission, *Review of the Gas Access Regime*, Report no. 31, 2004, Canberra.

[30] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, 2006.

[31] Productivity Commission, *Review of the National Access Regime*, Report no. 17, 2001, AusInfo, Canberra, pp.338-339.

[32] Productivity Commission, *Review of the Gas Access Regime*, Report no. 31, 2004, Canberra, p.262.

[33] Expert Panel on Energy Access Pricing, *Report to the Ministerial Council on Energy*, 2006, p.111.

To give effect to these views, the Expert Panel recommended that the NEL and NGL include common network pricing principles based on section 35 of the NEL. The Expert Panel recommended that the AEMC be required to make Rules that[34]:

- provide a reasonable opportunity for the recovery of efficient costs of providing services that are the subject of the network pricing determination and complying with a regulatory obligation;
- provide effective incentives to promote economic efficiency in the provision of network services, including for efficient investments and efficient provision of services;
- make allowance for the value of assets and the value of proposed new assets that form part of the network owned, controlled or operated by a network operator used to provide services that are the subject of a network pricing determination;
- have regard to any valuation of assets forming part of a transmission or distribution system, owned, controlled or operated by a network operator applied in any relevant determination or decision; and
- have regard to the economic costs and risks of potential under and over investment in assets and under and over utilisation of the capacity of assets.

The Commission has considered these reports and notes that they generally deal with the *level* of revenues or prices infrastructure providers are able to earn or charge, rather than the *methodologies* for determining prices. However, to the extent that these reports specifically considered pricing methodology, in particular the pricing principles in the Expert Panel report –, the Commission believes that the approach adopted in the Rule Proposal is consistent with the observations and recommendations made in those reports.

## 2.3 The approach in the existing Rules

Part C of Chapter 6 of the existing Rules for transmission pricing provides a highly detailed framework for the determination and implementation of prices for Prescribed Transmission Services.

In summary the existing transmission pricing approach involves the following steps:

- assets are categorised according to the services they deliver (for example, entry service asset, transmission use of system asset, etc);
- the aggregate annual revenue requirement (AARR) is allocated to categories of Prescribed Transmission Services as follows:
    - First, by subtracting non-asset related Common Service costs and allocating these to the Common Service category;

[34] Expert Panel on Energy Access Pricing 2006, 'Report to the Ministerial Council on Energy', pp.116-117.

- Second, by allocating the remainder of the AARR to Prescribed Transmission Service categories based on the optimised replacement cost (ORC) of the assets that provide that service as a share of the ORC of all the assets in the TNSP's regulated asset base;

- the AARR for each Prescribed Transmission Service is allocated to each asset based on its ORC as a share of the ORC of all the assets that provide that service. The amounts allocated to each asset in this manner are referred to as the 'annual cost' of those assets;

- the AARR for each Prescribed Transmission Service is allocated to connection points based on the annual costs of the network assets deemed to be used to provide the service to that connection point. For example, for Entry Services,[35] the cost allocated to the connected generator is the annual cost of the relevant entry assets; and

- the prices for using a particular Prescribed Transmission Service at a connection point are set in order to recover the relevant shares of the annual costs of assets allocated to that connection point.[36]

The Rules refer to this process as 'cost allocation' even though in practice there may be no direct relationship between the incurring of economic costs (such as expenditure on new assets) to provide a particular category of Prescribed Transmission Service, and the quantum of revenue recovered through charges for that service or at a particular connection point.

The existing Rules also employ a confusing mix of user pays, beneficiary pays and causer pays approaches to implement the cost allocation exercise. The primary means of allocation appears to be based on the *usage* of the relevant assets and operating

---

[35] A service provided to serve a *Generator* or group of *Generators* at a single *connection point*.

[36] See clauses 6.3 and 6.4 and Schedule 6.2. Also see Chapter 4.

expenditures incurred in providing the service. [37] In some cases, this appears in turn to be based on the identity of the *presumed beneficiary/ies* of the service. [38]

An additional requirement under the existing Rules is that the AARR cannot exceed the TNSP's maximum allowed revenue (MAR) from the provision of Prescribed Transmission Services for a given year.[39] Transmission prices for Prescribed Transmission Services are intended to recover TNSPs' AARRs as well as to provide appropriate signals for electricity consumption, production and investment decisions at various locations in the grid.

One of the more complicated aspects of this process is the allocation of allowable revenues relating to Prescribed TUoS Services to Transmission Customer connection points on a locational basis (part of the third step above). The CRNP or 'modified' CRNP methodologies are presently used for this purpose. Both of these methodologies seek to allocate the annual costs of particular network assets to Transmission Customer (load) connection points based on an engineering assessment of the transmission assets 'used' to convey electricity to those points.

The existing Rules also provide for ancillary matters such as the publication dates for transmission prices, requirements for the publication of negotiating framework by each TNSP, prudential requirements, billing and settlements process, pricing software and data and information requirements.

## 2.4 Approach in the Proposed Pricing Rule

The fundamental consideration underlying the Commission's Proposed Pricing Rule is a view that the NEM Objective, particularly efficiency in the use of, and investment in, electricity services, is best promoted by transmission prices being based, wherever feasible, on the costs of providing the services to those users who 'cause' the costs to be incurred.

---

[37] The body of Part C of Chapter 6 appears to base the allocation of TNSPs' AARR to categories of prescribed service on the *use* of particular assets in the provision of the relevant prescribed service. For example, clause 6.4 states:

This clause sets out the procedure to be used for allocation of the [AARR] amongst all the assets of the [TNSP] utilised in the provision of transmission services which will then provide a figure estimating the cost of providing those transmission services. This process is called 'cost allocation'.

The focus on use of infrastructure is supported by the National Grid Management Council's (NGMC's) document entitled "National Electricity Code, Outline and Rationale V1.0, 1 March 1996", which says:

Agreements reached by COAG required that network pricing be carried out in a cost reflective manner. The cost allocation process results in cost sharing between network services and locations in a manner which as far as possible reflects the actual costs involved in providing network services to each participant.

[38] For example, section 2 of Schedule 6.2 of the existing Rules describes 'entry and exit costs' as being recovered from the users "who benefit from them". This suggests that the allocation of these costs to connection points is currently based on presumed benefit.

[39] See clause 6.3.

The Commission's Proposed Pricing Rule is based on three key propositions:

- confirming the broad acceptability of the approach to pricing in the existing Rules (chapter 3 provides greater detail on the Commission's reasons supporting this view);
- recasting the pricing rules to a principles-based form by removing unnecessary detail on implementation and administration matters, while confirming that existing arrangements may largely continue to apply and providing certainty regarding pricing outcomes. The pricing principles have also been designed to allow innovation for alternative pricing methodologies to emerge over time subject to constraints in the Rules (chapter 4 provides greater detail of the Commission's reasons for its approach to the Proposed Pricing Rule); and
- making the procedural approach to pricing consistent with the approach taken by the Commission in its Draft Revenue Rule (chapter 5 provides greater detail on the Commission's reasons for its approach to the procedural requirements in the Proposed Pricing Rule).

The remainder of this chapter provides a brief overview of each of these propositions.

### 2.4.1 Confirming the broad approach to pricing

Having considered submissions, the Commission has reached the view that the arrangements in the existing Rules for determining how TNSPs' allowable revenues are recovered are broadly appropriate. That is, given the NEM Objective and the high-level economic efficiency considerations that flow from it, the Commission believes that the current Rules broadly ensure that the appropriate parties are paying the appropriate amount for transmission services. Chapter 3 discusses submissions on these matters and provides the Commission's detailed rationale for its position.

### 2.4.2 Recasting the pricing rules to a principles-based form

The Commission considered whether the existing Rules provided an unnecessarily detailed framework for the development, implementation and administration of prices for Prescribed Transmission Services, taking account of the views of stakeholders and the Commission's own analysis.

The Commission believed that the regulatory framework for pricing should reflect the Commission's approach to the framework for revenue regulation. In the Draft Revenue Rule, the Commission codified the key elements of a revenue-cap methodology. However, the Draft Revenue Rule delegated a number of more detailed *implementation elements* of the regime to the AER, including the form of the post-tax revenue model (PTRM) and the precise design and implementation of the incentive mechanisms to encourage efficiency in expenditure and service delivery.

This approach recognises the distinction between the key design features of the regulatory regime – such as methodologies and processes – that should be codified in Rules and the implementation elements that should not be codified in any level of detail. The codification of key design features is intended to provide a greater degree of certainty regarding the recovery of the efficient costs of service provision and the management of the potential for TNSPs to exercise market power. However, the provision of guided discretion on implementation elements of the regime to TNSPs and the AER has the benefit of enabling current practices to largely continue while allowing innovation to occur where appropriate.

In light of the proposed approach to revenue regulation and the views in submissions, the Commission believed that the current approach to the implementation and administration of pricing methodologies is inappropriately detailed. Therefore, the Proposed Pricing Rule embodied a shift to a principles-based regulatory framework. This means that the Rules should be confined to setting out pricing principles and requiring the implementation of the principles through pricing methodologies proposed by TNSPs for the approval of the AER in accordance with the Rules. This approach seeks to ensure consistency between the regulatory frameworks for transmission pricing and revenue.

In its submission to the Rule Proposal Report, the MEU considered that the proposed framework allows excessive freedom for TNSPs to structure transmission charges in a way that suits their needs and not the needs of consumers.[40] This was likely to lead to inconsistency of pricing across the NEM.

As discussed in more detail in chapter 4 (cost allocation) below, EnergyAustralia opposed the use of AER guidelines to establish substantive requirements on TNSPs. In EnergyAustralia's view, the role of AER guidelines should be to inform TNSPs in how the AER will administer a process of making a decision, not to set substantive requirements. This could create the risk of the AER effectively developing policy, which is an outcome the new NEM governance arrangements were intended to prevent. [41]

Integral was another stakeholder who considered that it was inappropriate for the AER to have the power to make guidelines, suggesting that this was contrary to the MCE's intended policy and legislative framework whereby rule making was separated from rule enforcement (p.2).[42]

EnergyAustralia also considered that the proposed tiered approach to regulation could result in diverse and inconsistent pricing arrangements across the NEM. This would produce uncertainty for TNSPs, the AER and customers (p.10). Similarly, while the NGF supported the tiered regulatory framework proposed by the Commission, which includes principles in the Rules, AER guidelines and TNSP pricing methodologies, the NGF expressed concern that this could compromise consistency of application across the NEM.

> "The NGF strongly recommends the development of explicit guidelines to ensure a market participant will see the same pricing process and basic pricing

[40] Major Energy Users, September 2006, p.22.

[41] EnergyAustralia, 26 September 2006, pp.9-10.

[42] Integral Energy, 25 September 2006, p.2.

methodologies regardless of which location in the NEM a transmission service is being sourced or negotiated."[43]

The only exception to consistent pricing methodology, in the NGF's view, ought to be where there were legitimate local circumstances that require specific treatment based on common criteria.

PIAC commented that despite its stated intention, the Commission's proposed approach contained excessively detailed requirements around the implementation of pricing methodologies.[44] Further, PIAC's understanding was that the proposed approach would not reduce the complexity of the actual pricing methodology applied by TNSPs. According to PIAC, the major consequence of the proposed change would be to make it easier for TNSPs to justify its pricing methodologies to the regulator and consumers would not benefit from this change. In PIAC's view, the current CRNP and modified CRNP models already provide considerable room for TNSPs to make decisions tailored to individual consumers' needs and there was no need to provide scope for more 'innovative' pricing approaches.[45]

The Commission continues to believe that a shift to a more principles-based approach to pricing is appropriate. In the context of the comments made in submissions on the Rule Proposal, the Commission notes that TNSPs in different jurisdictions already apply different pricing methodologies, with some using CRNP and some using modified CRNP. Further, the Commission understands that some differences currently exist in the way TNSPs interpret the existing Rules (including Schedule 6.2) regarding the process of allocating their allowable revenues to prescribed service categories ('cost allocation'). In general, the Commission supports differentiation of pricing approaches between TNSPs to the extent they reflect differences in local conditions and considers that the AER's approval role will help ensure that this remains the case in future. The Commission therefore maintains the view that the proposed regulatory framework will not increase the scope for TNSPs to act contrary to the interests of consumers, but will assist changes to methodologies that enhance efficiency and promote the interests of consumers in the long term.

The Commission's detailed discussion regarding the principles adopted and its response to submissions on the principles are described in further detail in chapter 4.

### 2.4.3 Development of the procedural framework for the Proposed Pricing Rule

The procedural approach adopted for the Proposed Pricing Rule involved:

- the TNSP proposing a pricing methodology prior to each regulatory control period;

---

43 National Generators Forum, 22 September 2006, p.3.

44 Public Interest Advocacy Centre, 26 September 2006, p.2.

45 Public Interest Advocacy Centre, 26 September 2006, p.2.

- the AER is being required by the Rules to approve the proposed methodology so long as it conforms to the principles in the Rules and the AER's guidelines (if applicable);
- the AER being able to substitute its own methodology where the proposed methodology does not conform to the Rules and the guidelines;
- the AER monitoring the TNSP's prices to ensure they are consistent with the approved pricing methodology.

The aim of this approach is to harness TNSPs' superior information about their physical networks and business operations in promoting the development of methodologies that satisfy the pricing principles in the Rules while minimising their implementation costs.

Overall, the Commission considered that the approach embodied in the Proposed Rule advances the NEM Objective by providing for a principles-based approach that facilitates efficiency in pricing, removing unnecessary prescription in Rules and allowing flexibility for innovative pricing methodologies to develop over time.

Generally submissions were supportive of the introduction of a procedural framework for transmission pricing. A further and more detailed discussion of submissions to the Proposed Pricing Rule is contained in chapter 5.

# 3 Key network pricing issues

In reviewing the transmission pricing rules, the Commission has examined the pricing methodology contained in the existing rules, and various problems with it as raised in submissions. As stated in the Pricing Rule Proposal Report the Commission does not presently believe there is a case for substantive changes to the existing arrangements for transmission pricing at the present time. However, as discussed below, this position is conditional on the outcomes of other reviews presently underway, particularly the CMR.

This chapter examines a number of the key issues associated with transmission network pricing and provides the Commission's detailed reasons for its view on these issues.

Prices for Prescribed Transmission Services are the means by which TNSPs are able to recover their regulated revenues (ie their AARRs). Therefore, any given set of transmission prices represents a response to the question of *who pays how much* towards the cost of providing Prescribed Transmission Services between:

- different types of network user – consumer network users and generator network users (and NSPs in their capacity as parties that inject or withdraw from the network);
- different locations of network user – network users located in different parts of a TNSP's network may be required to pay different amounts; and
- different consumption and generation patterns – network users with different consumption or production volumes or profiles may be required to pay different amounts.

The discussion below is structured around these three dimensions, and explains why the Commission believes that the current approach is largely consistent with the NEM Objective.

## 3.1 Transmission pricing between types of network users

### 3.1.1 Current approach in the Rules

As noted in the Pricing Issues Paper, under the current Rules, directly-connected electricity consumers (Transmission Customers) pay the majority of TNSPs' allowable revenues through charges for Prescribed Transmission Services. Generators pay only 'shallow' connection costs, being the costs of those assets specifically required to connect the generator to the existing shared network. Under the alternative, a 'deep' connection charging approach, the connecting party may be required to pay for any incremental investment elsewhere in the shared transmission network required to accommodate the new connection. Generators in the NEM also do not pay charges (known as use of system charges) in respect of the recovery of the costs of the existing shared network.

### 3.1.2 Approach in the Proposed Pricing Rule

The Commission did not consider there is a strong case at this time to move away from the existing allocation of allowable transmission revenues principally to loads (as opposed to generators). Given other signals operating in the market, requiring generators to either pay deep connection charges or to contribute towards the recovery of shared network costs would not materially improve the efficiency of generator locational investment decisions or otherwise promote the NEM Objective.

On the issue of deep connection charges, the Commission agreed with submissions that deep connection charges may create additional regulatory complexity and deter new generation investment, thereby harming competition and the long-term interests of end-use consumers. Further, it was considered that generation investment does not 'cause' new transmission investment to be undertaken. Shared transmission investment is primarily undertaken to serve the needs of reliable supply to loads. Therefore, in keeping with the high-level 'causer pays' principle[46], a move to deep connection charges for generators was not seen to be justified.

The Commission also did not believe there is a case for requiring generators to pay ongoing charges in respect of Prescribed TUoS Services. The Rule Proposal report noted that such a move would represent a profound shift from the existing arrangements and that it is far from clear whether it would be worthwhile. Generator TUoS charges would most likely be ultimately passed on to loads, potentially distorting bidding and dispatch in the process. While the British electricity market and several others do apply generator locational use of system charges, as noted in the Pricing Issues Paper, these markets generally have fewer (or one) pricing regions and different regulatory arrangements governing transmission investment. Further, the framework for Negotiated Transmission Services allows for Generators to agree to pay TNSPs for services that fall outside the definition of Prescribed Transmission Services adds additional emphasis to this approach.

For these reasons, and because the Commission is not aware of generator TUoS charges actually in operation anywhere in the NEM, the Commission proposed to remove the scope for prescribed Generator TUoS charges in the Rules.

### 3.1.3 Submissions on the Proposed Pricing Rule

EnergyAustralia supported the Commission's intention to maintain a shallow connection approach to new generator connections. EnergyAustralia also responded to the Commission's discussion of the VENCorp guidelines on connection augmentation by recognising that the Commission's approach in the Draft Revenue Rule towards the distinction between assets that provide negotiated and prescribed transmission services was consistent with whether an asset was likely to satisfy the Regulatory Test. EnergyAustralia considered that this was a move in the right direction, but noted the Commission's comments in its Draft Revenue Rule that this matter would best be dealt with through the cost allocation principles.[47]

---

[46] As discussed in Chapter 2 above.

[47] EnergyAustralia, 26 September 2006, p.8.

EnergyAustralia disagreed with the Commission's proposed removal of the scope for generator TUoS charges from the Rules. EnergyAustralia suggested that even if the Commission did not believe that the additional complexity, customer impacts and cost of introducing such a system is warranted at this time, the option to introduce a TUoS charging regime for generators should not be precluded in the future.

AGL also proposed that the Commission refrain from removing the scope for deep connection charges pending the outcomes of the CMR. AGL noted that ACCC's initial authorisation of the National Electricity Code anticipated that TNSPs would negotiate firm access arrangements (including payment terms) with their customers and that if TNSPs were unwilling to offer firm access, additional incentives or obligations on TNSPs may be necessary.[48]

InterGen was concerned with the Commission's conclusion that requiring new generators to pay deep connection charges would not materially improve the efficiency of new entrants' locational decisions. However, InterGen was supportive of this issue being considered under the CMR. In this context, InterGen believed that providing new generator entrants with some specified level of 'access' in exchange for a deep connection type of charge would be less complex and disruptive than a greater degree of locational pricing without allocated transmission property right for incumbents.[49]

Like InterGen, the NGF supported measures to provide long term certainty of transmission access to generators and considered that one way to address this issue was through generator charges for prescribed transmission services. The NGF believed that in the absence of such arrangements in the pricing Rule, the CMR was the appropriate forum for considering investment certainty and dynamic efficiency and that the proposed pricing rules should not influence or limit sensible changes to market arrangements relating to congestion management or investment signalling.[50]

The ERAA made the point that the transmission pricing review should not lead to rules that overlap or interfere with the outcomes of the CMR, nor preclude any future incorporation of performance incentive arrangements developed over time.[51]

The Institute of Public Affairs' submission supported a model where a new or expanded generator is required to pay for "any augmentation needed to allow its power to be transmitted"[52], suggesting that this would provide a better market signal than if transmission investment decisions were left in the hands of a regulator or transmission business.

The Total Environment Centre also supported a deep connection charging approach for generation, on the basis that a new large generator usually causes a TNSP to consider undertaking transmission augmentation. By contrast, the Total Environment Centre suggested that smaller local generators are currently sometimes charged more

---

48 AGL, 26 September 2006, pp.2-3.

49 InterGen, 25 September 2006, p.2.

50 National Generators Forum, 22 September 2006, p.2.

51 Energy Retailers Association of Australia, 25 September 2006, pp.1-2.

52 Institute of Public Affairs, September 2006, p.7.

than their direct costs of connection. The TEC considered that the VENCorp guidelines referred to in the Rule Proposal Report could provide a means for addressing these issues but the Commission has not set out a process for how this assessment could take place (p.5). [53]

The MEU also disagreed with the Commission's acceptance of a shallow connection charging approach to generators, suggesting that deep connection charges were necessary to provide locational signals to generators.[54] Moreover, due to dilution of transmission pricing signals through DNSP's charges, there is little efficiency benefit in exposing consumers to transmission prices. The MEU suggested that deep connection charging was therefore the most logical approach to promote efficiency. The MEU made similar points in favour of imposing generator TUoS charges.[55]

The MEU also suggested it was inappropriate for consumers to pay transmission charges based on peak demand that may only occur once per year (p.13). The MEU proposed that the Commission specify the precise price structure – ie the permitted basis of charging – that TNSPs should apply.[56]

PIAC suggested that the existing CRNP and modified CRNP methodologies represented a compromise between efficiency, equity, prescription and discretion. Moving to a guidelines approach for CRNP would change the nature of this compromise that, in PIAC's view, would imply weaker oversight and would not be matched by any gain in consumer benefit.[57]

### 3.1.4 Draft Determination

As noted in the Rule Proposal Report (p.41), the Commission does not believe that requiring generators to either pay deep connection charges or to contribute towards the recovery of shared network costs would materially improve the efficiency of generator locational investment decisions or otherwise promote the NEM Objective.

The Commission considers that the regulatory and market arrangements already provide significant signals to generators to locate in areas that are efficient from the point of view of the market as a whole and generator TUoS charges are unlikely to provide the best approach for improving these signals. A generator that locates in a remote region takes the risk that it will not be able to transport (and hence sell) its power to consumers – in other words, that it will be 'constrained-off'.[58] It is only if the generator is sufficiently low-cost that a regulated transmission augmentation to accommodate the evacuation of that generator's output is likely to satisfy the Regulatory Test by being the least-cost (or otherwise most net beneficial) way to serve load or meet reliability requirements. In this case, it could actually be *efficient for the*

---

[53] Total Environment Centre, September 2006, pp.4-5.

[54] Major Energy Users, September 2006, pp.11-12.

[55] Major Energy Users, September 2006, p.19.

[56] Major Energy Users, September 2006, p.20.

[57] Public Interest Advocacy Centre, 26 September 2006, p.3.

[58] This is not to say that the generator, when dispatched, receives the efficient price for its location. This issue is being considered in the Congestion Management Review.

*market as a whole and hence in the long term interests of consumers* for the generator to locate in its chosen (remote) location. If no regulated augmentation is likely to occur – because the combined cost of remote generation and the augmentation is relatively high – this is likely to discourage the generator proponent from locating in that (remote) area. Alternatively, the generator proponent is free to fund an augmentation at its own expense, which in itself provides a signal against remote location.

No further information has emerged from submissions to alter the Commission's understanding of the factors relevant to the efficiency of generator charges. In particular, submissions did not provide evidence that generators can 'cause' a TNSP to undertake downstream augmentation – such augmentations are generally only undertaken to serve the needs of load where necessary to satisfy reliability standards or promote net market benefits.

One exception to the shallow connection approach is where a new generator imposes a negative impact on the reliability or transfer capability of the transmission system – this impact is a 'negative externality' of the connection. In this case, the new generator should be charged for the cost of ensuring that the transmission network is 'left whole' by its connection. This aligns with the causer pays philosophy and should promote efficiency. Such costs should be recovered under the connection agreement and do not require the scope for generator TUoS charges to remain open. However, it is crucial that such charges do not extend to the costs of *expanding* network transfer capability, as this would go beyond charging new generators for the negative externalities they imposed on the rest of the system.

Therefore, even leaving aside issues of complexity, implementation cost and customer impacts, the Commission does not believe that preserving the scope for generator TUoS charges – and the attendant regulatory uncertainty this engenders – is necessary or appropriate. At the same time, it is acknowledged that the CMR may recommend different ways of dealing with transmission congestion, which could potentially have implications for the funding of transmission network upgrades to alleviate congestion. However, if and when such recommendations are adopted appropriate Rule changes can be developed at that time. The Commission therefore considers that its decision to revoke those Rules permitting generator TUoS charges neither pre-empts nor precludes other options arising from the CMR.

As for the MEU's point about whether it is appropriate for consumers to be charged for transmission based on their peak annual demand, the Commission believes that this is the correct outcome. Even if a consumer only requires an asset once per year, that asset nevertheless needs to be developed – and the costs incurred – to serve that need.

## 3.2 Transmission pricing between different network user locations

### 3.2.1 Current approach in the Rules

Under the current Rules, a share of TNSPs' allowable revenues allocated to Prescribed Use of System Services is recovered on a locational basis and the remainder on a postage-stamped basis. The locational share is allocated to Transmission Customer connection points based on the CRNP or modified CRNP methodologies contained in Schedule 6.4 of the Rules and is recovered through the Customer TUoS Usage Charge.

The postage-stamped share is recovered through the Customer TUoS General Charge, which also applies only to Transmission Customers.

### 3.2.2 Approach in the Proposed Pricing Rule

As with the broader 'who pays' question, the Commission was not persuaded that there is likely to be a material benefit in *mandating* a move away from the existing CRNP methodology. As noted above, transmission investment in the shared network is typically undertaken in order to meet the needs of electricity consumers. However, it is usually difficult to identify individual electricity consumers that directly trigger the need for any given investment in the shared network. This is because investments in the shared network – unlike most investments in connection assets – exhibit significant externalities as well as economies of scale and scope. Consequently, the causation principle used to recover the costs of Prescribed Entry and Exit Services cannot easily be applied to allocating the costs of shared network investments to individual network user connection points.

Rather, the Commission's preference was to set out principles in the Rules for the allocation of allowable revenues relating to Prescribed TUoS Services and allow TNSPs the flexibility to use CRNP, modified CRNP or some alternative that conforms to those principles. The AER would be responsible both for developing guidelines that clarified the implementation of CRNP (and modified CRNP) and for ensuring any methodology proposed by a TNSP accorded with the Rules.

### 3.2.3 Submissions on the Proposed Pricing Rule

Submissions on the Rule Proposal report and the Commission's response on issues relating to locational cost allocation issues including CRNP are summarised in chapter 4 below.

## 3.3 Transmission pricing for different consumption and production patterns

### 3.3.1 Current approach in the Rules

The existing Rules are, on the whole, less prescriptive about the basis upon which allowable transmission revenues are recovered than they are about the methodology for 'cost allocation'. While the Rules prescribe the pricing structures for Prescribed Entry and Exit charges, the Common Service Charge and the Customer TUoS General Charge, they provide a substantial degree of freedom to TNSPs to sculpt price structures for the Customer TUoS Usage Charge (the locational CRNP element).[59]

### 3.3.2 Approach in the Proposed Pricing Rule

The Commission believed that it is important for the Rules to provide principles for transmission pricing structure for the following reasons:

[59] See existing clauses 6.5.1-6.5.6.

- first, directly-connected consumers make up a substantial share of total electricity demand and consumption, suggesting that there are significant market benefits at stake in ensuring appropriate transmission pricing structures apply to (at least) this group; and

- second, as pointed out by the TEC submission, the Rules for distribution pricing may be reviewed in the light of metering and other developments providing an opportunity for consideration of alternate network pricing structures to smaller consumers, including the preservation of transmission pricing structures.

However, the Commission was reluctant to prescribe actual transmission pricing structures in the Rules and instead proposed to set out principles for their implementation by TNSPs as they develop pricing methodologies. The AER would then be obliged to assess whether the methodologies conformed to the principles. This approach recognised that regulatory prescription of price structures would be unnecessarily restrictive given the diversity in network conditions throughout the NEM while providing the scope for innovation in pricing methodologies and structures that promote efficiency and are therefore likely to promote the NEM Objective.

### 3.3.3 Submissions on the Proposed Pricing Rule

Submissions on the Rule Proposal Report, and the Commission's response on issues relating to pricing structure are summarised in chapter 4 below.

# 4 Principles for cost allocation and price structure

The previous chapter dealt with the Commission's approach to the overarching question of *who should pay how much* for the costs of providing Prescribed Transmission Services. This chapter focuses on the Commission's proposed specific pricing principles for the annual setting of maximum prices for Prescribed Transmission Services.

As noted in the Rule Proposal Report, the existing Rules require TNSPs to allocate (and ultimately recover) their AARRs to prices by undertaking the following three steps:

- Step 1: Cost allocation *between* Prescribed Transmission Services – this involves principles for allocating TNSPs' AARRs between different types of Prescribed Transmission Services;

- Step 2: Cost allocation *within* Prescribed Transmission Service categories – this involves principles for allocating the AARR for each Prescribed Transmission Service to individual network user connection points; and

- Step 3: Determination of prices to recover the costs of providing Prescribed Transmission Services – this involves principles for developing pricing structures that are applied to recover the allowable revenues allocated to each connection point.

This Draft Determination will not repeat the detailed description of the existing pricing methodology. However, a detailed explanation of the current approach is contained in the Rule Proposal Report.

The approach adopted by the Commission in its Proposed Pricing Rule was to develop a transmission pricing regulatory framework that supported the three-step allocation methodology as currently contained in the Rules. This approach has been continued in this Draft Determination.

Therefore, for each step in the existing three-step allocation methodology, this chapter:

- briefly describes the Commission's Proposed Pricing Rule;

- summarises submissions on the Commission's Proposed Pricing Rule; and

- discusses the reasoning for the Commission's Draft Determination.

## 4.1 Principles for Allocation of the AARR to Prescribed Transmission Service categories

### 4.1.1 Approach in the Proposed Pricing Rule

**Proposed Rule Step 1 Principles**[60]

The AARR for a given year is to be allocated as follows:

- in accordance with the *attributable cost share* for each pricing category of Prescribed Transmission Services;
- so that the same portion of AARR cannot be allocated more than once;
- where a portion of the AARR can be allocated to more than one pricing category of Prescribed Transmission Service, it is to be allocated according to the priority ordering outlined in the Rules.

There were two key elements of the Commission's proposed step 1 principles being:

- allocating the AARR to Prescribed Transmission Services on the basis of *attributable cost share;* and
- providing guidance on the priority of the AARRs allocation where a portion could be allocated to more than one pricing category of Prescribed Transmission Services.

Both of these concepts were explained in the Rule Proposal.

The AARR in the Proposed Rule was based on the TNSP's MAR and was adjusted for a number of variables including rewards and penalties from the TNSP's service target incentive scheme, previous over- and under-recovery of allowable revenue, expected IRSR proceeds and a range of cost pass-through items.

This approach to defining the AARR in the Proposed Rule differed from current practice in the existing Rules. Under the present Rules, adjustments to the amount of revenue that TNSPs are entitled to recover in a particular year through charges for Prescribed Transmission Services are reflected only in the magnitude of the Customer TUoS General Charge.

[60] Draft Pricing Rule clause 6A.24.2

### 4.1.2 'Up front' adjustments to derive AARR

**Submissions on the Proposed Pricing Rule**

Several parties disagreed with the Rule Proposal's approach of making 'up front' adjustment to the MAR to obtain the AARR. Under the existing Rules:

- non-asset common service costs are allocated directly to common service costs before the AARR is allocated to service categories on the basis of relative ORC asset values;
- adjustments for under/over-recoveries of the AARR in previous years are reflected in the TUoS General charge (the non-locational charge);
- intra-regional settlement residues (settlement surpluses arising primarily from the application of marginal rather than average intra-regional loss factors to generators' bids) are deducted from the revenue recovered through the TUoS General charge;
- inter-regional settlement residues (settlement residues primarily arising from flows between regions experiencing price differences) are primarily deducted from the revenue recovered through the TUoS Usage charge; [61] and
- network support payments are recovered through TUoS General charges (clause 6.4.3C(c)(3)).

The Proposed Rule defined AARR such that all but the first of these adjustments were made at the outset prior to the allocation of the AARR based on relative ORC asset values.

The ETNOFs submitted that this approach would lead to "a substantial reduction in entry and exit charges, and an off-setting increase in TUoS charges."[62] The ultimate impact would be to pass a proportion of expected IRSR proceeds and previous years' under/over-recoveries to generators, even though these amounts had been primarily derived from load customers. This would create distributional and fairness issues.

[61] Clause 6.19(c) requires TNSPs to use the IRSR and IRSR proceeds to adjust (reduce) the annual revenue requirement of assets that provide the interconnection. This means that those loads that notionally 'use' the interconnection assets under load flow analysis undertaken for the CRNP or modified CRNP methodologies enjoy lower TUoS Usage charges than they would if these amounts were used to adjust the AARR 'up front'.

[62] ETNOF, 25 September 2006, p.5.

EnergyAustralia also suggested that the Commission had not provided a sound justification for changing the way adjustments such as those due to IRSR proceeds were reflected in the charging regime. Like the ETNOFs, EnergyAustralia made the point that this would lead to more revenue being collected through the Customer TUoS General charge. According to EnergyAustralia, based on IRSRs of $60 million per annum to TransGrid and a total revenue cap of $430 million:

> *"This would result in a material year on year variation in the locational portion of the price signal* [ie the TUoS Usage price]*, which is intended to convey a long run price signal. This change in price setting will impact those customers who have high off peak energy use with a good load factor, while benefiting customers with poor load factor with peaky profiles. The proposed change will therefore run counter to the goal of efficient signalling."*[63]

### Draft Determination

The Commission acknowledged in its Rule Proposal Report that defining the AARR as adjusted for expected IRSR proceeds and previous years' under/over-recovery would imply a rebalancing of prescribed transmission service charges compared with the approach under the existing Rules in which these adjustments are reflected in the Customer TUoS General charge. The Commission also said at the time that it was interested in stakeholders' views on the likely materiality and consequences of this rebalancing.

The Commission has some reservations regarding the significance of the contentions raised in submissions. First, the ETNOFs did not explain why they thought the proposed changes would not improve transparency of the price-setting process. At first instance, it would seem more transparent and administratively simple that adjustments to the amount TNSPs are entitled to earn in a given year should be made at the outset in the determination of their AARRs rather than to a particular charge. Second, neither the ETNOFs nor EnergyAustralia provided any information on the magnitude (in terms of either $/MWh or % of final bill) of the likely rebalancing impacts on delivered electricity prices to consumers. Given that loads' exit charges would fall at the same time as TUoS General charges rise, the materiality of the rebalancing is unlikely to be significant.

Further, considering the ETNOFs' point about who contributes to the accumulation of IRSRs, it is not clear why all consumers should receive the benefits of settlement residues in any case. While consumers in importing regions contribute to the accrual of these IRSRs, the IRSRs arise because electricity in the importing region is relatively scarcer than electricity in the exporting region. Therefore, from an allocative (consumption and production decisions) and dynamic (locational investment decisions) efficiency perspective, it does not necessarily make sense for consumers to be shielded from the economic signals created by the supply and demand balance in the region by receiving the full benefit of the IRSR proceeds.

It is noted, however, that the rebalancing of charges due to up front adjustments to the MAR does involve a wealth transfer from existing loads to generators through the

---

[63] EnergyAustralia, 26 September 2006, pp.12-13.

means of recovering the costs of sunk transmission assets. Further, those loads that are likely to lose most from the rebalancing are those that are located electrically close to interconnector assets. This may not only cause unfavourable distributional impacts, but may also be inefficient. Under the load flow analysis undertaken for the CRNP methodology, these consumers are seen to 'use' the interconnector assets more than consumers that are electrically more distant from the assets. Under the existing Rules, IRSR proceeds must be first applied to reducing the annual cost (ie the 'annual revenue requirement') of interconnector assets. The rationale for this approach (in clause 6.19 of the Rules) is that the transmission assets forming part of interconnectors are larger – and hence more expensive – than if the transmission network were simply built to serve the requirements of loads in the area. Rather, transmission assets are oversized in relation to local load to accommodate larger-scale inter-regional exports or imports of power to serve load in other regions or elsewhere within the same region. This implies that consumers located on or near interconnectors themselves do not 'cause' transmission costs to be as high as the application of the CRNP methodology makes it appear. Therefore, if IRSR proceeds are instead used to reduce the AARR 'up front' as in the Commission's Proposed Rule, not only are consumers located on or near interconnectors likely to see their transmission charges rise by more than other consumers, but new loads may potentially be inefficiently deterred from locating in the same areas.

Considering EnergyAustralia's point that the rebalancing would reduce the locational Customer TUoS component, it is not clear that this would necessarily lead to inefficiency. As noted in the Issues Paper, the existing 50% CRNP/postage-stamp split of TUoS cost recovery only vaguely approximates the true LRMC of network usage. This is due to the various imperfections with CRNP as a reflection of 'true LRMC'. It follows that a small reduction in the amount to be recovered through the locational component of TUoS is just as likely to move the pricing regime as a whole closer to true LRMC as further away.

Another limitation to the current allocation of IRSR proceeds is that there is difficulty in determining what should happen if the proceeds exceed the annual costs of all the relevant interconnector assets. For example, if IRSR proceeds are very high, they may exceed the revenue allocated to interconnector assets. The Commission understands that different TNSPs have different ways of allocating the 'excess' IRSR proceeds. Also, at present there is not an appropriate consideration of the prospect of changes to regional boundaries and hence the definition of which transmission assets comprise an 'interconnector'. The Commission believes the 'upfront' adjustment alleviates the extent of this problem and provides increased transparency in this regard.

As for intra-regional settlement residues, these largely result from generators being settled on the basis of bids that are adjusted by the generators' assigned static marginal loss factors. As marginal loss factors tend to be about double average losses, this means that generators are effectively paid for less electricity than they actually supply. In this regard it is appropriate for generators to receive some benefit from intra-regional settlement residues.

On balance, the Commission is not convinced it should move away from the 'up front' adjustment approach reflected in the Proposed Rule in this Draft Determination. However, the Commission recognises that the arguments between the proposed approach and the status quo are finely balanced. Therefore, the Commission would welcome comments from stakeholders regarding the potential efficiency consequences of its proposed up front adjustment approach and will consider these in developing its Final Determination.

### 4.1.3 AARR definitional ambiguities

#### Submissions on the Proposed Pricing Rule

The ETNOF highlighted some apparent ambiguities or errors arising from the definition of the AARR. One issue was that the ability of TNSPs to recover from other customers foregone charges due to approved prudent discounts was unclear. Another issue was that operating and maintenance costs relating to common services – which were explicitly excluded from the definition of the AARR – did not appear recoverable through prescribed service charges.[64] Integral also made this point.[65] The ETNOF suggested that it would make sense for both of these amounts to be recovered through the non-locational element of charges for prescribed TUoS services.

The ETNOF recommended that the above issues could be dealt with by redefining AARR based on the definition in clause 6A.3.1 in the Draft Revenue Rule. That is, the AARR should be defined as:

"…the revenue that the TNSP is entitled to recover for the provision of prescribed services for the regulatory year in accordance with clause 6A.3.1."[66]

That said, the ETNOF considered that the current drafting of 6A.3.1 and 6A.3.2 contained some ambiguities because both clauses seek to define maximum allowed revenue. In the ETNOF's view, these clauses should be reviewed to ensure they provided a clear definition of the total revenue to be recovered through the prescribed pricing methodology in any given year.[67]

The ETNOF agreed with the proposed definition of ASRR, but noted that their proposed approach to the definition of the AARR would create some issues for the allocation of the ASRR to transmission connection points.[68]

#### Draft Determination

The Commission acknowledges that the drafting of the Pricing Rule Proposal may require some clarification and appreciates feedback from ETNOF and others on drafting matters. For example, the Commission is keen to ensure that both:

- operating and maintenance common service costs are recoverable through the Common Service charge – the Commission has amended 6A.24.3(e) to permit these costs being recovered through the Common Service Charge; and

---

[64] ETNOF, 25 September 2006, p.5.

[65] Integral Energy, 25 September 2006, p.2.

[66] ETNOF, 25 September 2006, p.5.

[67] ETNOF, 25 September 2006, p.6.

[68] ETNOF, 25 September 2006, pp.5-6.

- the foregone charges from prudent discounts that comply with the Rules can be recovered from charges to other customers – the Commission considers that no changes need to be made to allow discounts to be recovered from other charges.

### 4.1.4 Causation-based cost allocation approach

#### Submissions on the Proposed Pricing Rule

A number of parties questioned the appropriateness of the causation-based approach to allocating the AARR to categories of prescribed transmission services and warned that it could lead to significant price shocks for customers without offsetting benefits.

The ETNOF gave an example where a new customer connects to an existing substation installed for an existing customer. A causation-based allocation approach would lead to the new customer only being charged the incremental cost of connection (eg a new feeder bay) rather than contributing to the cost of the substation. This would represent a material change to the existing arrangements. In this context, ETNOF noted that while the Commission's Rule Proposal Report had expressed an intention to not permit reclassification of a shared asset to a connection asset, it was unclear whether the reverse could occur.[69]

Hydro Tasmania also suggested that the causation-based cost allocation approach could lead to a large number of assets currently treated as part of the shared network being regarded as being directly attributable to providing prescribed entry services. Hydro Tasmania's comment appeared to stem from its concern that certain radial lines connecting hydro-electric generators were not fully dedicated to providing connection to a single generator or group of generators.[70] Hydro Tasmania also raised a number of questions regarding the application of the causation test. The first question was *when* the test was meant to be applied – the first time the new Part J was applied by a TNSP or when an asset first came into existence. If the former, Hydro Tasmania expressed concern that a number of asset providing shared network services could be regarded as being 'directly attributable' to providing entry services. If the latter, then Hydro Tasmania asked what would happen if the use of the asset had changed over time. Hydro Tasmania supported transitional provisions that prevented the cost of existing shared transmission assets being reallocated to prescribed (entry) services due to a change in the use of the assets or for any other reason (see also below under 'general/miscellaneous'). Hydro Tasmania also considered that the existing provisions in Schedule 6.2 are valuable and should be carried over into the new pricing Rule. [71]

More specifically, the ETNOFs criticised aspects of the definition of 'attributable cost share' in the Proposed Rule. The ETNOFs believed that the definition:

- did not describe principles for allocation but instead mandated a choice of two broad allocation models: It would be more appropriate for the Rules to instead require TNSPs to have regard to some high-level principles (such as those in the

---

[69] ETNOF, 25 September 2006, p.8.

[70] Hydro Tasmania, 26 September 2006, p.5.

[71] Hydro Tasmania, 26 September 2006, pp.6-7.

existing clause 6.1.1(c)) in determining how the AARR gets allocated to prescribed transmission service categories;

- erroneously referred to adjustments required under clause 6A.24.3: This clause describes principles for the allocation of the ASRR to connection points, so the ETNOFs thought it was unclear how this would affect the allocation of the AARR to prescribed service categories; and

- referred to asset values 'contained in the accounts of the TNSP': The ETNOFs noted that ORC values may not be included in TNSPs' accounts and therefore the Proposed Rule drafting may not allow the continuation of existing practice.

Instead, the ETNOFs proposed that the definition of attributable cost share be based on (as paraphrased):

- The proportion of asset costs directly attributable to the provision of the category of prescribed transmission service;

- The proportion of operating and maintenance costs directly attributable to the provision of the category of prescribed transmission service; **or**

- Some other method that gives effect to the pricing principles (such as those in the existing clause 6.1.1(c)),

  where 'asset costs' fairly reflects an accepted valuation method.[72]

EnergyAustralia also commented on issues arising from the definition of attributable cost share. EnergyAustralia contended that if a TNSP were to undertake cost allocation based primarily on the basis of the relative operating and maintenance costs of providing a prescribed service, this would likely represent a major shift from current cost allocation outcomes. This is because, according to EnergyAustralia:

> "The proportion of opex to RAB is almost immaterial so allocating revenues based on opex can lead to very different and inappropriate results."[73]

On the issue of the appropriate asset values to be used to allocate the AARR, EnergyAustralia believed that TNSPs maintain asset registers on an ORC basis to comply with accounting standards – therefore, there was no need to permit other types of valuation methods to be used.

Integral proposed that the Draft Rules should be amended to support pricing methodology being based on marginal cost pricing rather than recovery of a TNSP's AARR.[74]

---

[72] ETNOF, 25 September 2006, pp.8-9.

[73] EnergyAustralia, 26 September 2006, p.11.

[74] Integral Energy, 25 September 2006, p.1.

**Draft Determination**

As noted in the Issues Paper and Rule Proposal, the current Part C of Chapter 6 and Schedule 6.2 of the Rules are unclear on the basis that such 'cost allocation' should occur, with beneficiary-pays, user-pays and causer-pays philosophies all reflected in various places of the existing drafting. It is also noted that the implications of a shift to a causer pays basis is a topic on which stakeholders have made a number of valuable points in their submissions.

It is acknowledged that cost allocation based on causation may require TNSPs to adopt different processes to what they have historically done. However, the Commission remains of the view that causation is a more appropriate basis for allocating costs than usage or benefit. Where *new* transmission investments are undertaken, the Draft Revenue Rule only permits the costs of those investments to be recovered from prescribed service charges where the investment would satisfy the Regulatory Test or otherwise be necessary and justifiable under the Rules. If an investment would not satisfy these criteria, a transmission customer may request the TNSP to undertake the investment and fund the costs of the investment itself. The VENCorp guidelines provide for a situation where a party may pay the incremental cost of bringing forward an investment that would later satisfy the Regulatory Test or pay the amount by which the net benefits of the investment fall below what would be necessary for that investment to satisfy the Regulatory Test. This suggests that the costs attributed to negotiated transmission services are those that cannot justifiably be attributed to prescribed transmission services.

The Commission believes that the cost allocation process for *existing* transmission assets in the Pricing Rule should be consistent with the arrangements under the Draft Revenue Rule for determining whether the costs of new transmission investments should be recovered from negotiated or prescribed service charges.

With respect to the timing of this assessment, the Rule Proposal contemplated that the determination of the service causing the development of each asset (ie the identity of the prescribed service to which the asset would be attributed) would be assessed as at the date the asset was commissioned or expense was incurred. This would have involved TNSPs in a review of the original historical rationale for the development of each of their assets. In this Draft Determination, the Commission has taken the view that while an historical assessment of the rationale for asset development may be, strictly speaking, more consistent with the proposed approach for the allocation of transmission investment costs going forward, it was likely to be unworkable and could lead to significant price shocks to transmission customers.

On this basis, the Draft Rules provide that, as at the date the Proposed Rule was published (24 August 2006), assets currently in existence are attributed to prescribed service categories on a directly attributable (ie causation) basis *at that point in time*, and take existing generation and load as given. This means each TNSP would need to make an assessment, for each transmission asset within their RAB, as to the provision of which prescribed transmission service or services would necessitate (ie. 'cause') the presence of that asset were the asset to be developed on that day. This approach should serve to reduce price shocks caused by the revised approach to cost allocation. However, to the extent changes from the status quo occur – and these should be relatively minor – the Commission considers that they are warranted in order to:

- Ensure that the appropriate costs are allocated to the different categories of prescribed transmission service, in order to facilitate the locational (CRNP) charge being reflective of the LRMC of the network; and

- Promote consistency between the means of allocating the costs of prescribed services and the means of determining whether future assets are attributed to prescribed or negotiated services.

This clarification of the directly attributable concept is implemented through a draft clause 11.6.2.

The Commission also considers that it is important that the pricing rules are consistent with the approach taken for transmission revenue with regard to the future allocation of costs between transmission users. In addition to the causation test that determines if an asset forms part of a Negotiated or Prescribed Transmission Service, the Draft Revenue Rule states that Negotiated Transmission Services can be subject to adjustment over time to the extent that the assets are used to provide service to another person[75]. Treatment of prices under this arrangement would be required to be consistent with the Cost Allocation Methodology and, therefore, the Cost Allocation Principles.

As discussed above TNSPs will be required to determine the 'cause' of costs on the existing network at a particular point in time in a similar manner to how this will occur into the future as between Negotiated Transmission Services and Prescribed Transmission Services. Unlike the approach for revenue, however, when applying this test to costs that have been 'caused' by previous connection requests these will remain part of the regulated asset base (only when there is no agreement in terms of price) and not a Negotiated Transmission Service. Therefore, these network connection assets will be treated, in terms of cost allocation and price, as Prescribed Transmission Services.

The Commission considers that where the 'cause' of a transmission asset is determined to be an entry service, the pricing framework should be consistent with the pricing and cost allocation framework introduced for Negotiated Transmission Services. That is, adjustment should be allowed over time to the extent that the assets used provide services to another person. Therefore, the Commission considers that the Draft Pricing Rule should allow for this consistency in approach by requiring that entry services, where the agreements do not determine the price or where the agreement refers to Part C of the Chapter 6 Rules, apply the Negotiated Transmission Service arrangements in relation to price.

In addition, consistent with the approach taken for transmission revenue, the Commission considers that where assets are determined to be caused by users of the shared network, these assets should not be reallocated to entry services into the future.

This approach will not require that assets to be removed from the regulatory asset base, but it will ensure that existing entry assets are treated in a consistent manner with

[75] Draft Revenue Rule clause 6A.9.1(6).

respect to cost allocation and price to those that will exist under the new transmission regulation framework. The Commission maintains that attribution based on causation in this manner is likely to remain more robust and stable than allocation based on a beneficiary-pays approach in which the extent to which a party benefits can vary from dispatch interval to dispatch interval as network flows, spot prices and dispatch or consumption levels change.

The Commission also considered specific comments made by ETNOF on the definition of 'attributable cost share'. The Commission disagrees with ETNOF's contention that the Proposed Rule mandated a choice of two broad allocation models – one based on relative asset values and the other based on relative operating and maintenance expenditures. Rather, as explained in the Rule Proposal Report, the intent was to accommodate the existing arrangements where the AARR allocation is based on the relative ORC of the assets developed to provide a particular Prescribed Transmission Service. However, the Proposed Rule provisions also allow alternative approaches so long as they are based on a well-accepted conception of the relative cost or value of the relevant asset and other expenditures directly attributable (on a causation basis) to the provision of a service.

On this basis, it is considered that there is no need at this stage to expand the options for allocating the AARR to prescribed service categories, as suggested by ETNOF, to allow TNSPs to undertake the allocation based on the satisfaction of high-level economic principles such as those in the existing clause 6.1.1(c). The application of such high-level principles to cost allocation would leave the process too open-ended to provide the necessary degree of predictability to transmission customers.

At the same time, the Commission notes the comments of EnergyAustralia that if a TNSP were to undertake cost allocation based primarily on the basis of the relative operating and maintenance costs of providing a prescribed service (rather than on the basis of relative ORC asset values as at present), this would likely represent a major shift from current cost allocation outcomes. It is acknowledged that this could lead to unintended price shocks for little if any gain in terms of promoting the market objective. Therefore, the Draft Rule has been revised such that the 'attributable cost share' must *substantially reflect* the ratio of (only) asset costs directly attributable to that service.

Finally, the Commission has changed the reference in the Proposed Rule to "costs of transmission system assets" to explicitly include "optimised replacement cost" as well as costs that are referable to values contained in the TNSP's accounts.

### 4.1.5 Priority Ordering Approach

### Submissions on the Proposed Pricing Rule

The 'priority ordering' principles also attracted significant comment. The ETNOF submitted that application of these principles would be a major exercise and would require substantial guidance from the AEMC or the AER in order to ensure a broadly consistent approach across networks. The ETNOF cautioned "…against the adoption in the Rules of new allocation procedures based on economic concepts such as standalone costs, which are typically difficult to apply in practice.".[76] Furthermore, according to the ETNOF, TNSPs already apply reasonable methods for delineating between prescribed transmission services.

Therefore, the ETNOF proposed that where certain assets or operating and maintenance expenses could potentially be attributable to more than one category of prescribed transmission services, TNSPs should be allowed to apply any allocation approach that is consistent with high-level principles such as those in the current clause 6.1.1(c). According to the ETNOFs, this would allow TNSPs to continue to apply their own methods for delineating between the categories, based on clause 6.3.1(a) and Schedule 6.2 of the existing Rules.[77]

As an aside, the ETNOF contended that VENCorp's guidelines are not necessarily consistent with the Commission's expressed preference for a shallow connection policy because a generator may be required to contribute to investment in the shared network.[78]

Hydro Tasmania also commented on the priority ordering provisions. Hydro Tasmania suggested that the proposed ordering of the cost allocation (entry services first, followed by use of system and common services) could lead to the allocation of all the basic costs of the substation to a generator. According to Hydro Tasmania, this fails to recognise that most generators connect into existing shared network substations.[79]

The NGF had similar concerns to Hydro Tasmania on the priority ordering provisions. Under the Commission's proposed approach, costs that could potentially be attributed to more than one service category are firstly allocated to entry or exit services. According to the NGF, this represented a clear departure from the status quo, and opened the risk of large increases in connection charges, where such costs may currently be allocated to shared services. The NGF noted that under the cost allocation principles in the Draft Revenue Rule, costs relating to assets that had historically been classified as 'shared' could not be reallocated to negotiated services. The NGF contended that a similar non-reversion approach should apply to 'legacy' (prescribed) connection services – once costs have been allocated to the provision of shared services (TUoS and common service) , they should not be reallocated to prescribed generator connection costs.[80]

The NGF also raised concerns regarding modification to legacy assets due to a network configuration or refurbishment. In the NGF's view, it was unclear whether any increase in asset value also forms part of the RAB or would be deemed to be part of the cost of a negotiated service.[81]

---

[76] ETNOF, 25 September 2006, p.15.

[77] ETNOF, 25 September 2006, p.15.

[78] ETNOF, 25 September 2006, p.13.

[79] Hydro Tasmania, 26 September 2006, p.8.

[80] National Generators Forum, 25 September 2006, pp.3-4.

[81] National Generators Forum, 25 September 2006, p.4.

### Draft Determination

In order to further promote consistency between the cost allocation process for regulated revenues and the approach in the Revenue Rule for the allocation of costs between negotiated and prescribed services, the Commission has reconsidered its proposed 'priority ordering'. As noted above, under the Draft Revenue Rule, the costs attributed to negotiated transmission services (including *new* entry or exit services) are effectively those that cannot justifiably be attributed to prescribed transmission services (ie TUoS services or common services). For example, if an investment satisfies the Regulatory Test for any reason, the cost of that investment will be allocated to the provision of prescribed transmission services (ie prescribed TUoS or common service rather than negotiated entry or exit services). Consistent with this approach it would be appropriate to rearrange the priority ordering so that where an asset or expense is directly attributable to the provision of *several* prescribed services, the attendant costs should be allocated:

- first to prescribed transmission use of system services, to the extent that the asset cost (on a standalone basis) is directly attributable to the provision of use of system services;
- second to (prescribed) common services to the extent that the asset cost (on a standalone basis) is directly attributable to the provision of common services; and
- third, to prescribed entry/exit services.

This is effectively the same order of allocation that is expected to occur under the Draft Revenue Rule.

It is expected that this clarification should address concerns raised by Hydro Tasmania, the ETNOFs and the NGF that 'shared' assets may be allocated to prescribed entry or exit services. Hence, if an asset is needed both to serve load and provide, say, entry services (ie the 'cause' of the asset is both the provision of TUoS and entry services) then it should be 'directly attributable' *first* to the provision of TUoS services. It is only if the cost of the relevant asset is greater than the cost of a standalone asset providing TUoS services is the remainder allocated to prescribed entry services.

At this stage, the Commission is unconvinced of the ETNOF submission that the application of economic concepts such as 'standalone cost' are inappropriate to apply to the allocation and recovery of transmission regulated revenues. However, it is acknowledged there is a potential difficulty and cost of applying this economic concept to real-life situations such as historical transmission assets developed over a number of years. The Commission's intent is that TNSPs would undertake an internal desktop-style study of their assets and make an informed but approximate judgment as to the relevant standalone costs of providing different services rather than engage in a prolonged and detailed DORC-style consultant-led audit and evaluation of their assets. Ultimately, it will be AER that monitors TNSPs' conformance with the Rules and approved pricing methodologies. However, the Commission wishes to make its intent clear on these matters.

Regarding the NGF's concern, the Commission's approach in the Revenue Rules has been to define connection services as negotiable into the future, recognising that these services are generally between two commercial enterprises such that a negotiable outcome is preferable to regulation for the achievement of the NEM objective. In this regard, it would be appropriate that any replacement or reconfiguration of a connection asset, grandfathered as providing prescribed services in accordance with Rule 11.5.11, should be treated as a negotiated service asset.

The Draft Revenue Rule does however, address the underlying concern of the NGF that where benefits from a replacement or reconfiguration are primarily caused for the benefit of the shared network, then these costs should be allocated to the shared network. Rule 6A.19.2(a)(8) provides for costs to be allocated from negotiated to prescribed services on the basis that the costs are either 'directly attributable to the provision of prescribed services or are incurred in providing prescribed services.' This allows costs to be allocated from or between negotiated and prescribed services on the basis of who primarily caused the costs to be incurred. The Commission believes that these Rule provisions address the concerns identified by the NGF.

### 4.1.6 Role for AER guidelines

#### Submissions on the Proposed Pricing Rule

ETNOF put forward the view that provision for the AER's guidelines to clarify the **meaning** of 'attributable cost share' and 'attributable connection point cost share' should be removed on the basis that it is not appropriate for the AER's guidelines to define terms that are critical to the operation of the Pricing Rule.[82] EnergyAustralia supported this position in relation to the definition of CRNP and more generally (see below).[83]

#### Draft Determination

The Commission agrees with ETNOF and EnergyAustralia that the role of AER guidelines should not include clarifying the **meaning** of 'attributable cost share' and 'attributable connection point cost share'. Further than this, the Commission has come to the view that AER guidelines on the **application** of 'attributable cost share' and 'attributable connection point cost share' are unlikely to be necessary, as the proper application of these concepts will (appropriately) tend to vary on a case-by-case basis. Therefore, the Draft Pricing Rule has been amended to remove guidelines on these concepts from clause 6A.25.2. For similar reasons, the Commission does not believe AER guidelines are necessary on the types of transmission assets are typically developed to provide different categories of prescribed transmission services (clause 6A.25.2(d)). Once again, this is a matter that is best resolved on a case-by-case basis and any guidelines would replicate the problems in the existing Schedule 6.2. Finally, as discussed further below in 4.2, the Commission does not believe AER guidelines are necessary to elaborate the operation and application of the CRNP or modified CRNP methodologies (clause 6A.25.2(e)).

---

[82] ETNOF, 25 September 2006, p.18.

[83] EnergyAustralia, 26 September 2006, p.10.

### 4.1.7 Other issues

#### Submissions on the Proposed Pricing Rule

ETNOF believed that the clarity of the proposed arrangements for pricing would be increased if:

- A number of terms were included in the definitions section: AARR, ASRR, 'attributable cost share' and 'attributable connection point share'.[84]

- The term 'Common transmission services' should be relabelled '*Prescribed* common transmission services' in order to avoid confusion, as all other categories of prescribed transmission services have the word 'prescribed' in their title.[85]

- A diagram providing an overview of the three allocation steps was included in the Pricing Rule.[86]

Hydro Tasmania made a number of points regarding appropriate savings and transitional provisions. Hydro Tasmania noted that many pre-NEM connection agreements would have provided for pricing to be determined under provisions in the applicable regulatory instruments. This means that pricing under these agreements would be subject to the changes proposed by the Commission even though the Commission expressed an intention that existing pricing arrangements should continue to apply. Hydro Tasmania suggested that the Rules be clarified to ensure this is the case and that the new Rule will not apply to charges under existing connection agreements unless the relevant parties agree to apply the new provisions.[87]

The Commission also notes the ETNOF's drafting comment on the reference in clause 6A.22.5 (attributable cost share) to adjustments required under the principles in clause 6A.24.3 (which deals with ASRR). The Commission has corrected this cross-reference error to clause 6A.24.2, which relates to the AARR rather than the ASRR.

#### Draft Determination

The Commission agrees with the proposals by the ETNOF to include a number of terms in the definitions section and to relabel the definition of Common Transmission Services as this will increase the clarity and simplicity of the Rules. Alternatively, it is considered that the proposal to include a diagram of the three allocation steps in the Rules will not necessarily assist in providing clarity and consistency in the application of the Rules. Therefore, this proposal has not been adopted for the Draft Pricing Rule.

Regarding comments made by Hydro Tasmania on savings and transitional arrangements, the Commission has come to the view that the originally proposed clause 6A.33 is unnecessary. Where a connection agreement provides for the

---

[84] ETNOF, 25 September 2006, pp.3-4.

[85] ETNOF, 25 September 2006, p.10.

[86] ETNOF, 25 September 2006, pp.11-12.

[87] Hydro Tasmania, 26 September 2006, pp.9-12

calculation and determination of prices for entry or exit services, such services will not be prescribed services under [draft] clause 11.5.11. Therefore, there is no need to 'grandfather' the charging regime for such services. On the other hand, as previously stated, where an entry connection agreement defers the connection charge determination to regulatory arrangements such as the Rules or National Electricity or is silent on price the arrangements for negotiated Transmission Services will apply with respect to price.

In addition, as noted above, the Commission has determined that the test for directly attributable should occur as at the date of the Rule Proposal with existing generation and load taken as given. The Commission considers that this arrangement should appropriately address Hydro Tasmania's concerns.

## 4.2 Allocation of the ASRR to connection points

A TNSP allocates the AARR amongst different Prescribed Transmission Services and so allocated is called the annual service revenue requirement (ASRR) in the Proposed Pricing Rule.[88] This section discusses how the ASRR is subsequently allocated amongst network user connection points.

### 4.2.1 Approach in the Proposed Pricing Rule

The intention of Step 1 is to allocate a TNSP's AARR amongst different Prescribed Transmission Services. This allocated revenue is known in the Proposed Rule as the annual service revenue requirement (ASRR). This section discusses how the ASRR allocated to each Prescribed Transmission Service should be further allocated amongst network user connection points.

[88] Clause 6A.24.3 of the Draft Pricing Rule

**Proposed Principles for Allocation of ASRR to Connection Points (Step 2 principles)[89]**

The ASRR is to be allocated in accordance with the following principles:

- The ASRR allocated to Prescribed Exit or Entry Services is to be allocated to Transmission Customers or Generators (as the case may be) on the basis of the 'attributable connection point cost share' of the individual Prescribed Exit or Entry Service provided to each Transmission Customer or Generator;
- The ASRR allocated to Prescribed TUoS Services is to be allocated to Transmission Customer connection points in the following manner:
    - a portion is to be allocated on the basis of the 'estimated proportionate use' of the relevant network assets by each of those Transmission Customers with CRNP or modified CRNP being two permitted means of making this estimation; and
    - the remainder is to be allocated by the application of a postage-stamped price;
- For the ASRR allocated to Prescribed TUoS Services, the shares of the locational and non-locational components must be either a 50% share allocated to each component or an alternative allocation based on a reasonable estimate of future network utilisation and the likely need for future transmission investment with the objective of providing more efficient locational price signals;
- The ASRR allocated to Common Transmission Services for Transmission Customers is to be allocated by the application of a postage-stamped price.

  'Postage stamped' price refers to an identical unit price applied to connection points throughout the relevant region(s).

### For Prescribed Entry and Exit Services

The Proposed Rule required the ASRR for Prescribed Entry Services and Prescribed Exit Services to be allocated to individual connection points in a similar way to how the AARR is allocated to different Prescribed Transmission Service categories.[90] As with the allocation of the AARR to categories of Prescribed Transmission Services, the Proposed Rule sought to accommodate existing practice by allowing TNSPs to continue allocating the ASRR based on the relative ORCs of the assets that provide each Prescribed Entry/Exit Service.

That is, it was considered for the Proposed Rule that the allocation should be based on the 'attributable cost share' of each individual Prescribed Entry and Exit Service. The 'attributable connection point cost share' would then be based on the relative asset costs and/or O&M costs directly attributable (on a causation basis) to provide the

[89] Clause 6A.24.3 of the Proposed Pricing Rule

[90] Clause 6A.24.3 (a) and (b)

service *to that network user* as a proportion of *total* asset costs and/or O&M costs directly attributable (on a causation basis) to provide *all* Prescribed Entry and Exit Services. The emphasis to be given to relative asset costs as compared to relative O&M costs was considered to be a matter for the TNSP to determine.

### For Prescribed Transmission Use of System Services[91]

The Proposed Rule required a portion of the ASRR for Prescribed TUoS Services to be allocated to Transmission Customer connection points on a locational basis and the remainder to be allocated on a postage-stamped basis. The locational component was to be based on the 'estimated proportionate use' of the relevant network assets by each of those Transmission Customers, with CRNP and modified CRNP explicitly referred to as permitted means of estimating proportionate use.

The Proposed Rule also contained new definitions of CRNP and modified CRNP to replace the lengthy descriptions in Schedule 6.4 of the existing Rules. In seeking to promote certainty, the Proposed Rule allowed the AER to make guidelines to clarify the requirements of these allocation methodologies.

### Common Transmission Service

The Proposed Rule required the ASRR allocated to Common Transmission Services to be recovered through a postage-stamped price[92] (see also price structure below). The intention of this was to limit any rebalancing of Prescribed Transmission Service charges to Transmission Customers in different locations and help maintain the stability and predictability of the pricing arrangements.

## 4.2.2 Definition of ASRR

### Submissions on the Proposed Pricing Rule

As noted above, ETNOF considered that the allocation of the ASRR to connection points was necessary due to its proposed changes to the definition of AARR. The required changes would involve:

- making adjustments to the non-locational component of the ASRR for prescribed transmission use of system services to reflect previous years' over- or under-recovery of prescribed revenues; and
- making adjustments to either the locational or non-locational components of the ASRR for prescribed transmission use of system services to reflect estimate IRSRs, based on high-level pricing principles similar to those in the existing clause 6.1.1(c).[93]

---

[91] Clause 6A.24.3 (c ) and (d)

[92] Clause 6A.24.3(e) of the Proposed Pricing Rule

[93] ETNOF, 25 September 2006, p.16.

### Draft Determination

As the Commission has decided to maintain the 'up front' adjustment approach to deriving the AARR, the changes suggested by the ETNOFs to the definition of ASRR are not appropriate.

### 4.2.3 Definition of 'attributable connection point cost share'

### Submissions on the Proposed Pricing Rule

The concept of 'attributable connection point cost share' is applicable to the allocation of the ASRR for prescribed entry and exit services to transmission customer connection points. As with the definition of 'attributable cost share', ETNOF contended that the Proposed Rule inappropriately restricted the manner in which allowable revenues could be allocated. Instead, ETNOF proposed that the allocation should be made on a reasonable basis using one of the same three methods ETNOF proposed for attributable cost share: proportionate asset values, proportionate operating and maintenance expenses and any other method that complies with high-level pricing principles. Also, as with the attributable cost share definition, ETNOF suggested that transmission asset costs should be based on an accepted valuation method rather than be referable to values contained in the relevant TNSP's accounts.[94]

### Draft Determination

The Commission does not believe that the modifications suggested by ETNOF are necessary. As with the definition of 'attributable cost share', there is no need to expand the options for allocating the ASRR for prescribed entry and exit services to customer connection points, as suggested by ETNOF, to allow TNSPs to undertake the allocation based on the satisfaction of high-level economic principles such as those in the existing clause 6.1.1(c). Once again, the application of such high-level principles to cost allocation would leave the process too open-ended to provide the necessary degree of predictability to transmission customers.

However, for the sake of consistency with the definition of attributable cost share, the Proposed Rule has been revised such that the 'attributable connection point cost share' must *substantially reflect* the ratio of asset costs directly attributable to that service. This is in recognition of the fact that asset costs are likely to be a much larger contributor to the costs of providing prescribed entry and exit services than operating costs.

### 4.2.4 CRNP and modified CRNP

### Submissions on the Proposed Pricing Rule

EnergyAustralia had no major objection to the approach in the Proposed Rule for allocating the ASRR among connection points. EnergyAustralia supported the continuation of CRNP and considered that the Rules should unequivocally preserve CRNP as the default pricing mechanism and not allow it to be modified without a change to the Rules – it should not be amendable by the AER through guidelines. In

[94] ETNOF, 25 September 2006, p.9.

EnergyAustralia's view, the role of AER guidelines should be to inform TNSPs in how the AER will administer a process of make a decision, not to set substantive requirements. The AER is unlikely to be able to improve on the existing CRNP methodology and if any change occurs, it should involve TNSPs' pricing practitioners.[95]

For its part, the AER believed that six months was insufficient to develop pricing methodology guidelines and requested an additional six months (12 months in all). The matter of timing is discussed further in the procedural framework chapter.

EnergyAustralia considered that the Rule Proposal removed some of the bias against 'modified CRNP', which should allow the pricing methodology to better reflect the specific conditions of the network at a point in time (p.13). In EnergyAustralia's view, this should lead to more efficient pricing outcomes but may create distributional impacts. One concern of EnergyAustralia was the risk the approach in the Proposed Rule could allow the AER to develop guidelines that were overly intrusive in terms of specifying the most appropriate methodology to use under given network conditions. EnergyAustralia suggested that to avoid this risk, the Commission could map out a scale of capacity utilisation levels and the corresponding proportion of the usage charge component applied by TNSPs under a modified CRNP regime.[96]

The Total Environment Centre also supported the continuation of CRNP and modified CRNP on the basis that TNSPs have limited incentives to set prices to reflect LRMC. However, the Total Environment Centre considered that the Commission had not presented sufficient reasons to *not* set out a detailed pricing methodology in the Rules. They considered a detailed pricing methodology prescribed in the Rules would reduce variation across jurisdictions and assist in setting prices efficiently.[97]

### Draft Determination

The Commission acknowledges the concern expressed by EnergyAustralia that obliging the AER to develop guidelines clarifying the CRNP and modified CRNP methodologies could lead to poor outcomes in the proposed timeframe, especially if TNSPs' pricing specialists were not involved in the process. The AER also requested that the Rules allow 12 months rather than six months for them to develop all of their guidelines. Having considered this issue further since the publication of the Rule Proposal and consulted informally with ETNOF, the Commission is no longer convinced that there is significant value in requiring the AER to develop guidelines on CRNP and modified CRNP and has therefore deleted this provision. Given this, as well as the removal of references to guidelines on two other matters, the Commission does not consider the AER requires such a long extension to the proposed six month period to prepare the guidelines required in the Draft Rule. However, the Commission does want to ensure that the AER has sufficient time to make well developed guidelines. Therefore, the Commission has amended the Draft Pricing Rule to require the initial guidelines be developed by 30 September 2006.

---

[95] EnergyAustralia, 26 September 2006, pp.9-10.

[96] EnergyAustralia, 26 September 2006, p.13.

[97] Total Environment Centre, September 2006, pp.3-4.

The Commission acknowledges EnergyAustralia's suggestion of mapping out a scale of capacity utilisation levels and the corresponding proportion of the usage charge component applied by TNSPs under a modified CRNP regime. However, this would involve a level of implementation detail that it not appropriate for the Rules. As indicated in the Pricing Issues Paper,[98] the relationship between transmission asset utilisation and the appropriate share of TUoS costs to be recovered through locational charges in order to yield a reasonable approximation of LRMC is likely to vary considerably across a grid and is therefore hardly a matter for codification in the Rules. Therefore, the Commission has declined to amend the Draft Pricing Rule to incorporate this suggestion.

Finally, in response to the point made by the Total Environment Centre and as discussed in chapter 2, the Commission does not believe it is appropriate to develop Rules that go to the detail of implementing pricing principles. Moreover, variation in methodologies across jurisdictions may be appropriate to efficiently reflect local conditions.

## 4.3 Price structure principles

This section develops and discusses the principles for pricing structures used to recover the portions of the ASRRs allocated to each connection point for each Prescribed Transmission Service category.

### 4.3.1 Approach in the Proposed Pricing Rule[99]

**Proposed Step 3 Principles**

- For the recovery of the ASRR, a TNSP is to develop separate prices for each category of Prescribed Transmission Service in accordance with the following principles;
  - prices for Prescribed Entry and Exit Services must be a fixed annual amount;
  - prices for Common Transmission Service must be postage-stamped;
  - prices to recover the location component of Prescribed TUoS Services ASRR must be based on levels of demand or consumption at times of greatest utilisation of the transmission network and for which network investment is most likely to be contemplated and not change by more than 2% per annum compared to the load-weighted average price for this component for the relevant region(s);
  - prices to recover the non-locational component of Prescribed TUoS Services ASRR must also be postage-stamped.

[98] AEMC 2006, Proposed National Electricity Amendment (Pricing of Prescribed Transmission Services) Rule 2006, Rule Proposal Report, 24 August 2006, Sydney, pp.50-51.

[99] Clause 6A.24.4

The Commission approach to developing pricing principles to guide price structures in the Proposed Pricing Rule were as follows:

- For Prescribed Entry and Exit Services - TNSPs must determine a fixed annual price at each connection point that recovers the share of the Prescribed Entry or Exit ASRR allocated to that connection point;[100]

- For:

    - Common Transmission Service ASRR; and the

    - Non-locational component of the Prescribed TUoS Services ASRR,

  prices must be postage-stamped;[101]

- For charges recovering the locational component of Prescribed TUoS Services ASRR, the Commission believed that the price should be structured to signal the potential long term consequences of actual or potential Transmission Customers' use of the network. It was considered that this would provide appropriate outcomes because it is the locational component that is intended to reflect the LRMC of future network usage at various points in the grid. Therefore, the Proposed Rule provided that the pricing structure must be based on demand or consumption at times that result in the highest levels of network utilisation and for which investment is most likely to be contemplated.

In addition, the Commission decided to retain the current 2 per cent 'side constraint' on any given locational price compared with the average load-weighted locational price for the relevant region(s), due to concerns in submissions to the Issues Paper about the potential impact on charges if this constraint was removed. This approach was different to the existing Rules – which simply refer to 'average' price – the addition of the 'load-weighted' prefix should clarify the intended operation of this principle.

In the Proposed Pricing Rule the Commission did not provide a detailed methodology for determining whether the postage-stamped prices for Common Transmission Services and Customer TUoS General Charges should be energy-based (ie $/MWh) or capacity-based (ie $/MW). Rather, the Commission considered that TNSPs should be able to propose the basis for postage stamp pricing that they consider is most appropriate to their circumstances.

Finally, the Commission highlighted that where pricing for Prescribed Entry and Exit Services is determined under the terms of connection agreements entered into on or before 24 August 2006, these Rules do not apply.[102]

---

[100] This approach is consistent with the current requirements in Part C of Chapter 6.

[101] This approach is also consistent with the current requirements in Part C of Chapter 6.

[102] See Proposed Rule 6A.33.

### 4.3.2 Submissions on the Proposed Pricing Rule

ETNOF generally supported the proposed price structure principles and had some relatively minor drafting comments. These were that the description in brackets in each of the clauses should be deleted and that the 'fixed annual amount' charge for entry and exit services be clarified to refer to prices that do not vary with energy usage or demand.[103]

ETNOF also had some concerns about the appropriateness of the proposed 2% 'side constraints' of the locational component of prescribed use of system prices. These concerns derived from cases where there was a step change in load or incentives for new connecting parties to game the constraint by initially understating their demand levels. While gaming may be difficult to carry off successfully, step changes in load can mean that the TUoS Usage price (the locational price) are well above or below what is appropriate for the new load level.[104]

EnergyAustralia supported the Proposed Rule on pricing structure, suggesting that TNSPs should have flexibility to determine the most appropriate pricing structure taking account of the circumstances of their network and the relevant customer(s).[105]

### 4.3.3 Draft Determination

The Commission considers that submissions have not suggested that the approach to price structures in the Rule Proposal is materially in need of revision. However, it does consider that there may be some merit in ensuring that where a customer has requested a material step change in demand that the Rules should allow some flexibility in regard to the 2 per cent constraint. Therefore, further comment is sought from stakeholders regarding the materiality of this issue and if allowance for this should be made in the Rules. However, considering that the Commission did not receive substantial comment regarding a problem in this area it is reluctant to make a change at this stage.

[103] ETNOF, 25 September 2006, p.16.

[104] ETNOF, 25 September 2006, p.17.

[105] EnergyAustralia, 26 September 2006, pp.13-14.

# 5 Procedural framework

An important element of the Commission's approach to transmission pricing is the specification of rules to provide a transparent and timely process for the making of transmission pricing decisions. By clarifying the obligations of parties involved in the regulatory process, greater certainty can be provided to market participants, with associated reductions in the time necessary for regulatory decisions making.

The key features of the Commission's proposed procedural framework are:

- an obligation on the AER to develop Pricing Methodology Guidelines in a number of specified areas;
- aligning the obligations and timeframes for approval of a proposed pricing methodology with the process proposed in the Draft Revenue Rule for approval of a Revenue Proposal and proposed negotiating framework.

This chapter describes the procedural requirements that the Commission proposed, the response from submissions, and the Commission's Draft Determination in response to submissions.

## 5.1 Approach in the Proposed Pricing Rule

The Commission considered it appropriate that the consultation and approval process that will apply to a revenue cap determination and a proposed negotiating framework, as detailed in the Draft Revenue Rule, should also apply to approval of a proposed pricing methodology. The Commission considered that this integration of processes will allow for a streamlined and efficient regime for the TNSP to propose its pricing methodology, and at the same time allow market participants and the regulator to obtain a better overall understanding of the links between revenue and pricing and the overall impact of the transmission determination.

The AER's role in the approval process was that it has to be satisfied that the proposed pricing methodology gives effect to the pricing principles. On this basis the Proposed Rule provided for a framework that included:

- pricing Principles contained in the Rules, as outlined in the chapter 4;
- the development of Pricing Methodology Guidelines by the AER to facilitate TNSP decision making in relation to the preparation of a proposed pricing methodology;
- a consultation and approval process that starts with a requirement for TNSPs to submit a proposed pricing methodology that conforms to the Pricing Principles in the Rules and the AER's Guidelines;
- a requirement for the AER to approve a proposed pricing methodology if it is consistent with, and gives effect to, the Pricing Principles and the Guidelines,
- a requirement for TNSPs to calculate and set prices for Prescribed Transmission Services in accordance with an (approved) pricing methodology;

- a requirement for TNSPs' approved Pricing Methodologies to be published on the website of the TNSP;
- a requirement for TNSPs to publish prices annually; and
- the maintenance of most existing obligations regarding prudential requirements and billing and settlement.

With the removal of existing detailed requirements from the Rules for transmission pricing, the Commission sought to ensure that transmission network users have the opportunity to be well informed on the price-setting process. The Commission believed that by requiring approval and publication of a pricing methodology as the basis for setting prices during a regulatory control period, the TNSP's pricing decision making is more transparent and improved participant understanding of the transmission price setting mechanism.

## 5.2 General Procedural Issues

### 5.2.1 Submissions on the Proposed Pricing Rule

The MEU had substantial concerns that the proposed procedural framework gave too much discretion to TNSPs to develop pricing methodologies that produced perverse or undesirable outcomes.[106] For example, the MEU believed that the framework would prevent the AER from rejecting a proposal even if it was convinced that the TNSP was not complying with the 'fundamental requirement' of cost reflectivity. The MEU also raised the question of the definition of the customer connection point.

EnergyAustralia requested that certain aspects of the procedural framework should be clarified. These were:

- whether an approved pricing methodology would operate for the same period of time as the regulatory control period; and
- whether an approved pricing methodology can be revisited or modified during a regulatory control period if necessary to reflect a change in circumstances;

Where there is a co-ordinating TNSP in a region, the Rules should ensure that the 'appointing' TNSPs in the region are not required to submit and have approved separate pricing methodologies.[107]

AGL made the point that the Rules do not provide explicit guidance in relation to bank guarantees for generator TUoS and connection payments. AGL said that it believed the Rules should state that TNSPs cannot require a bank guarantee from customers that are rated at least BBB minus, in line with the requirements for DNSPs in Victoria.[108]

[106] Major Energy Users, September 2006, p.28.

[107] EnergyAustralia, 26 September 2006, p.15.

[108] AGL, 26 September 2006, p.3.

### 5.2.2 Draft Determination

In response to the MEU concerns, the Commission does not believe that the proposed framework takes away the ability of the AER to reject a TNSP's proposed pricing methodology if it led to undesirable outcomes. The Proposed Rule provide some, but nevertheless limited, flexibility for TNSPs to propose modifications to existing methodologies. On the matter of the definition of the customer connection point, this will generally be a matter for negotiation between the parties and – consistent with the approach in the Revenue Rule – this will often be the point up to which the TNSP considers transmission investments will satisfy the requirements of the Regulatory Test or can otherwise be justified as part of the cost of providing prescribed TUoS or common services.

Recognising the potential ambiguities on the procedural framework identified by EnergyAustralia, the Commission has made amendments to ensure that:

- an approved pricing methodology *would* operate for the same period of time as the regulatory control period – the Commission's view is that changes during a regulatory control period are unlikely to require an alternation to pricing methodology, especially given that the existing methodology in Part C of Chapter 6 has been largely unchanged since the start of the NEM;

- an approved pricing methodology *could* be revoked during a regulatory control period if it was based on information provided by the TNSP that was materially false or misleading or if the development of the pricing methodology involved a material error – this amendment reflects the equivalent provision for revenue determinations in draft clause 6A.15; and

- where there is a co-ordinating TNSP in a region, the Rules provide that the 'appointing' TNSPs in the region are not required to submit, and have approved, separate pricing methodologies – this is a logical position based on avoiding duplication and ambiguity.

With respect to AGL's point, the Commission considers that this is outside the scope of the present Review and is therefore, not the appropriate forum for making substantive changes to such arrangements.

## 5.3 Requirement for guidelines

### 5.3.1 Submissions on the Proposed Pricing Rule

As noted in the discussion of cost allocation in chapter 4 above, EnergyAustralia expressed strong concerns with the Proposed Rule's imposition of obligations on the AER to develop pricing methodology guidelines. EnergyAustralia believed that the guidelines would only augment the Rule requirements and could result in contradictions, misinterpretations and inconsistencies. EnergyAustralia stated that it would prefer the Rules to detail the pricing methodology and for the AER's role to be restricted to ensuring TNSPs' methodologies complied with the Rules and their prices were consistent with the approved methodology. Therefore, AER guidelines ought to be restricted to procedural rather than policy matters.[109]

Integral also believed, as noted in chapter 2 above, that it was inappropriate for the AER to have the ability to make guidelines on pricing methodologies.[110]

EnergyAustralia also expressed concerns about the role in the Proposed Rule for the AER to develop information guidelines. Consistent with its position on the revenue Rule, EnergyAustralia believed that these should be set out in the Rules.[111]

### 5.3.2 Draft Determination

As noted in other chapters, the Commission has decided to remove three topics from the scope of the guidelines that the AER is required to develop partly in recognition of these concerns (see clause 6A.25.2).[112]

On the matter of consultation, EnergyAustralia believed that consultation requirements should not be triggered if a TNSP applies an established pricing methodology such as CRNP – the requirements should only apply where a new methodology is proposed.

The Commission considers that as pricing methodologies are only approved at the start of each regulatory control period, the requirement for consultation should remain. This is because even if the methodology does not change, the appropriateness of it may change as network conditions change over time.

## 5.4 Timing of Price Methodology Proposals

### 5.4.1 Submissions on the Proposed Pricing Rule

The ETNOF broadly supported, in principle, the Commission's proposal to align the timing requirements of each TNSP's pricing methodology and revenue cap submission. However, the ETNOF was concerned that this could lead to timing and resourcing problems for TNSPs because TNSPs are required to submit final prices to DNSPs prior to late March each year to enable them to submit their proposed DUoS and TUoS prices to the regulator on 1 April for approval. However, in some instances the Proposed Rule provides for the AER's final approval of a TNSP's pricing methodology by April or May, some weeks after the TNSP must have advised DNSPs of its prices for prescribed transmission services.

The ETNOF suggested that one of the following three alternatives be adopted instead:

- bringing forward the timing of the approval of the TNSP's proposed pricing methodology;

---

[109] EnergyAustralia, 26 September 2006, pp.9-10.

[110] Integral Energy, 25 September 2006, p.3.

[111] EnergyAustralia, 26 September 2006, p.16.

[112]Draft Rule, clauses 6A.25.2(d-f) removed.

- retain the proposed concurrent review and approval process, but allow the approved pricing methodology to be implemented in the second (rather than first) year of the new regulatory period; or

- abandon concurrent timing of the revenue and pricing processes.

The ETNOF said it had no particular preference amongst these options. [113]

VENCorp also highlighted a concern it had due to their requirements to submit its revenue proposal in early 2007, before the development of the AER's pricing guidelines. VENCorp identified three options for addressing this issue and stated its preference as submitting a pricing methodology after the guidelines have been developed, but noted that this would be inconsistent with the proposed approach of aligning TNSPs' revenue and pricing applications. VENCorp therefore sought a transitional arrangement to facilitate its proposed solution.[114]

The AER made several comments on the procedural framework. The AER was of the view that the proposed timeframe for developing pricing methodology guidelines under the Proposed Rule was insufficient. The AER requested that the Draft Rule provides it with 12 months (by 31 December 2007) instead of the proposed six months (by 1 July 2007) to complete the guidelines. The AER also highlights that transitional arrangements for SP AusNet, VENCorp and ElectraNet are required because their revenue reset applications must be lodged in early 2007, well ahead of even the proposed 1 July 2007 deadline for guidelines. The AER suggested that the existing provisions of Part C of Chapter 6 be grandfathered for these businesses.[115]

The AER also raised concerns about the pricing methodology approval process. It said that these concerns were similar to those it raised in relation to the transmission revenue Rule. More specifically, the issues were:

- Resubmission of a non-compliant pricing methodology proposal – clause 6A.26.4 of the Proposed Rule requires TNSPs to resubmit their proposals if the AER identifies compliance issues "as soon as practicable thereafter". This should be amended to be no more than one month.

- Submission of a revised pricing methodology proposal – clause 6A.26.8 of the Proposed Rule allows TNSPs to submit a revised pricing methodology following the release of the AER's Draft Decision on its original pricing methodology, but places no constraints on the scope of changes that may be made. The AER is concerned that such an open-ended right to revise may render the AER's analysis and consultation on the initial proposal redundant and not allow the AER sufficient time to properly assess the revised proposal. The AER recommended

---

[113] ETNOF, 25 September 2006, pp.18-19.

[114] VENCorp, 2 October 2006, p.2.

[115] Australian Energy Regulator, 20 September 2006, pp.1-2.

that revisions to a TNSP's methodology after the Draft Decision be limited to addressing concerns raised in the AER's Draft Decision. [116]

EnergyAustralia and Integral pointed out that the current date of publication for transmission prices in the Rules (15th May) is too late to be implemented into distribution prices for the coming financial year. Therefore, TNSPs should be required to publish prices by March 15 each year.[117]

### 5.4.2 Draft Determination

The Commission appreciates the issues raised by stakeholders regarding the required timing of pricing determinations and how this interacts with DNSPs' obligations to submit their prices to jurisdictional regulators. However, the Commission does not consider that it is necessary for the Rules to be amended to accommodate these concerns. In particular, this is because the expiry of transmission revenue and pricing determinations can vary over time and between businesses, therefore changes to the Rules may not adequately address all situations. The Commission considers that in instances where a TNSP has not yet finalised prices because it has yet to get its Pricing Methodology approved that it can use draft prices and recover any under or over amount in the following year.

The Commission has the view that it is important to allow the AER sufficient time to develop robust guidelines for the regulatory framework. The AER proposed that the deadline for the finalisation of the guidelines should be 31 December 2006. However, by removing some of the more detailed items from the guidelines much of the difficulties in achieving the timeframe are reduced. In light of the reduced scope of the guidelines the Commission is of the view that the date for their finalisation should be amended to 30 September 2006.

The Commission recognises the concerns of the AER regarding the scope of resubmitted proposals following the AER's draft determination and assessment of the initial Pricing Methodology. The Commission considers that it is important that the regulatory regime provides certainty and predictability to market participants through the decision making process. Consequently, the Draft Pricing Rule requires that revisions to TNSPs' Revenue Proposals following a draft determination be restricted to those necessary to substantially incorporate the changes required or address matters identified as being of concern to the regulator in its draft determination.

In addition, the AER were concerned that there should be a time limit for the resubmitted Pricing Methodology where it was deemed to be non-compliant. The Commission considers that because the guidelines and Rules are known to the TNSPs on an *ex ante* basis that such a constraint is likely to provide additional discipline in the submission of compliant proposals. Therefore, a one month time constraint for resubmitted Pricing Methodologies has been included in the Draft Pricing Rule.

---

[116] Australian Energy Regulatory, 20 September 2006, pp.2-3.

[117] EnergyAustralia, 26 September 2006, p.17, and Integral Energy, 25 September 2006, p.4.

Regarding the savings and transitional issue raised by VENCorp and the AER the Commission is aware that transitional provisions will be required by those businesses undergoing a review in 2007. As pointed out by VENCorp the transitional arrangements will mainly be required as a result of the need for the AER to develop guidelines on price related issues. However, as noted earlier, the Commission has substantially reduced the scope of those guidelines. Due to this reduction in scope the Commission considers that interim guidelines can be developed for the remaining issues so that the affected businesses can submit a Proposed Pricing Methodology at the commencement of the review of their revenue requirements.

# 6 Prudent discounts

A feature of the existing Rules (clause 6.5.8) is that TNSPs are allowed (but not obliged) to negotiate a lower price for Prescribed Transmission Services than what is provided for in clauses 6.5.1 to 6.5.6. Where a TNSP agrees to a lower Customer TUoS General Charge or Transmission Customer Common Service Charge, the TNSP may recover the foregone amount from other Transmission Customers, so long as the TNSP has complied with the AER's "Guidelines for the Negotiation of Discounted Transmission Charges" (AER Guidelines)[118].

The rationale for allowing these 'prudent discounts' is to prevent *inefficient by-pass* of the transmission network. 'By-pass' in this context refers to:

- technical by-pass – such as the development of a duplicate transmission line from a power station to a large load; as well as
- economic by-pass – such as a decision to not invest in or expand a load or to shut down an existing operation.

By-passing the existing transmission network can in some instances be efficient as a lower cost option may be available. This would occur where an alternative option has a lower cost compared to transmission charges based on the incremental cost of using the network. However, if the alternative option is only lower cost because transmission charges are greater than the incremental costs, then by-pass will be inefficient.

Under the Draft Revenue Rule, TNSPs will only face the risk of regulatory optimisation of assets within their RABs if:

- those assets no longer contribute to the provision of Prescribed Transmission Services;
- those assets are worth more than $20 million (indexed) and are dedicated to a single network user or a small number of Transmission Network Users; and
- the TNSP has not sought to negotiate a discount or enter arrangements to manage the risk of the assets being commercially stranded.[119]

This provides TNSPs with a strong incentive to negotiate prudent discounts in respect of services provided by certain dedicated assets. The question then is, how should the Rules minimise the risk of inefficient by-pass occurring.

The remainder of this chapter outlines the Commission's Proposed Rule and submissions on it, plus the Commission's response to submissions.

---

118 Then the ACCC: ACCC, Guidelines for the Negotiation of Discounted Transmission Charges, 3 May 2002.

119 Clause 6A.2.3 of the Draft Revenue Rule.

## 6.1 Approach in the Proposed Pricing Rule

The Commission agreed with the position expressed in the majority of submissions to the Issues Paper that the Rules should provide scope for the negotiation of prudent discounts, where appropriate. However, it was considered that the workability of the discounting arrangements could be enhanced in a number of ways. These included:

- elevating the AER's existing negotiation guidelines into the Rules;
- allowing (but not obliging) a TNSP to seek 'up front' approval from the AER for recovery of a discount and where such approval is granted, for it to be effective for the duration of the TNSP's (original) agreement with the relevant Transmission Customer; and
- providing a process in the Rules to apply to the AER's consideration of a TNSP's up front application for approval of a proposed recovery amount.

The Commission also agreed that the recovery from other Transmission Customers of discounts given under the pre-AER regime should be "grandfathered" and the Proposed Rule includes this provision[120].

Finally, the Commission did not believe that prudent discounts, which relate to prescribed transmission services, ought to be the subject of a negotiating framework that applies to negotiated transmission services.

## 6.2 Submissions on the Proposed Pricing Rule

The AER generally supported the proposed arrangements for prudent discounts in the Rules. However, the AER suggested that its approval of a discount should lapse where the size of the discount is varied or the duration of the agreement permitting the discount is extended (the AER proposed drafting changes to effect this suggestion). The Proposed Rule only allowed the AER's approval to lapse within the duration of an agreement where false or misleading information was provided.[121]

Alcoa supported prudent discounts but made the following contentions:

- the by-pass test should be amended to confirm that it applies to economic by-pass as well as technical by-pass (Alcoa suggested some drafting to achieve this);
- the maximum discount should be limited by the need for the customer to at least pay incremental cost, which may be represented by CRNP (though not perfectly);
- TNSPs have insufficient incentives to negotiate discounts because:
    - TNSPs have incentives to defer capex under the incentive regime for revenue;

[120] Clause 6A.27.2(l)

[121] Australian Energy Regulator, 20 September 2006, p.3.

- o there is limited realistic optimisation risk for underused assets given the fact that organic load growth would generally prevent optimisation from occurring; and
- o TNSPs face revenue cap regulation, so there is limited incentive to expand load and throughput in their networks.

Therefore, TNSPs should be subject to an obligation to negotiate in good faith with a customer if a discount is requested, with recourse to binding arbitration undertaken by the AER or another dispute resolution body if necessary.[122]

Queensland Rail also submitted that the test in the Proposed Rule was ambiguous and should ensure that it applies to economic as well as technical by-pass. Queensland Rail also considered that there was limited incentive on TNSPs to negotiate discounts due to the revenue cap approach to transmission regulation and rapid load growth reducing the prospect of regulatory optimisation occurring. Therefore, Queensland Rail suggested that there should be access to customers to binding arbitration in the event that a TNSP does not wish to negotiate a discount.[123]

The MEU also raised the point that under the new revenue arrangements, there is now little pressure on TNSPs to negotiate a prudent discount. The MEU suggested that there were likely to be very few transmission assets in the NEM that are likely to be at risk of stranding under the commercial stranding arrangements.[124]

## 6.3 Draft Determination

The Commission agrees with the AER that approval of a discount should lapse in either of the cases it refers to. These caveats were within the Commission's original intention and the drafting of clause 6A.27.2(j) has been revised to ensure it reflects this.

The Commission disagrees with both Synergies' report for Alcoa and Queensland Rail that the criteria for a prudent discount could potentially exclude 'economic' by-pass. The wording of clause 6A.27.1(e)(1) is specifically designed to allow for the widest possible range of by-pass behaviours (technical and economic) to warrant the giving of a prudent discount. The Commission notes that these words were chosen by the AER (then the ACCC) precisely to ensure economic by-pass considerations were taken into account in the discount assessment process:

> "Depending on the context, an alternative scenario may for example involve by-passing parts of the network, *not connecting to the network* or *refraining from increasing demand for electricity*."[125] [Emphasis added]

---

122 Synergies Economic Consulting, Alcoa's Submission to the AEMC, 25 September 2006.

123 Queensland Rail, 25 September 2006, p.1.

124 Major Energy Users, September 2006, p.30.

125 See ACCC, Guidelines for the Negotiation of Discounted Transmission Charges, 3 May 2002, (Discount Guidelines) p.1; See also ACCC, Guidelines for the Negotiation of Discounted Transmission Charges, Decision, 3 May 2002 (Discount Decision), pp.11-12.

Therefore, the Commission presently considers it unnecessary to make the amendments requested in the Synergies' report for Alcoa regarding discount criteria. However, for the avoidance of doubt in the interpretation of the proposed pricing Rule, the Commission's firm intent is that economic as well as technical by-pass options be considered in determining whether a discount is warranted. The Commission is also open to receiving evidence that the way the equivalent discount guideline has been interpreted by the AER/ACCC in the past does not support this intention, as suggested by the Synergies report.[126]

As for whether TNSPs should be obliged to negotiate discounts in good faith with discount seekers with recourse to binding dispute resolution, the Commission has not been persuaded that such measures are required to ensure thet effective commercial negotiations occur. No evidence has been presented to the Commission that TNSPs currently lack incentives to negotiate discounts with customers that have genuine by-pass options (including deciding to relocate or not to invest). Moreover, the approach in the Draft Revenue Rule of allowing for commercial stranding of some assets remains to be put into effect as an incentive for TNSPs to offer discounts in certain circumstances. For these reasons, the Commission has not included additional requirements in relation to the negotiation of prudent discounts in the Draft Rule.

[126] Synergies Economic Consulting, Alcoa's Submission to the AEMC, 25 September 2006, p.12.

# 7 TUoS rebates to embedded generators

The current Rules allow rebates of Customer TUoS usage charges to be provided to embedded generators, arising from savings made by DNSPs when an embedded generator locates in their network. At present, 100 per cent of this saving is required to be passed through to the embedded generator. The rationale for this mandated approach is twofold. First, embedded generators are considered to create savings in future transmission augmentation costs. Therefore, the rebate is intended to provide an incentive for generators to locate in load-rich areas to help defer or avoid the need for future transmission investment. Second, DNSPs are considered to be in a superior bargaining position so that negotiation between the DNSP and the embedded generator proponent is not expected to result in appropriate outcomes.

The key question that the Commission has considered is whether the existing rebate arrangements should continue, or whether it is appropriate to modify the existing arrangements in some way. Some approaches for modifying the existing arrangements considered by the Commission include:

- allowing the rebate to reflect only the Customer TUoS Usage Charge (currently based on CRNP or modified CRNP) or alternatively both the Customer TUoS Usage and General Charges (which are currently a postage-stamped charge that recovers the remaining revenue requirement allocated to prescribed TUoS Services);

- allowing the rebate to apply to demand side management and non-electricity alternatives as well as embedded generation, as these other options may also help defer or avoid the need for transmission investment; and

- allowing the rebate to equal the full TUoS saving accruing to DNSPs (as is currently the case) or whether it should be a matter for negotiation between the parties.

Another issue that is relevant given the Commission's Draft Revenue Rule is the interaction between TUoS rebates and network support payments that can be offered to embedded generators through the application of the Regulatory Test. The question is whether embedded generators should be able to claim both TUoS rebates as well as network support payments.

In general, the Commission's approach to the Proposed Pricing Rule is to not radically change the existing transmission pricing arrangements. Nevertheless, there is a case for aligning the greater emphasis placed by the Commission on negotiation in the Draft Revenue Rule and the determination of remuneration provided to embedded generators.

## 7.1 Approach in the Proposed Pricing Rule

In the Proposed Pricing Rule the Commission maintained the existing arrangements for TUoS rebates. However, the Commission sought submission on three options that arose from consultation. These options were:

- that TUoS rebates apply to generators up to 10 MW in capacity while larger generators remain eligible for network support payments; or
- that a minimum threshold be defined to account for the reasonable costs of administering the TUoS rebate; or
- maintain the existing arrangements but require any network support payments to an embedded generator reflect the expected TUoS rebates they would receive.

## 7.2 Submissions on the Proposed Pricing Rule

ETNOF said it broadly supported the three options outlined in the Rule Proposal Report. In particular:

- "ETNOF strongly supports the proposition that any network support payments made to an embedded generator should be adjusted to reflect the expected TUoS rebates that the generator will receive, to ensure that there is no 'double dipping'.
- ETNOF also sees merit in the proposition that TUoS rebates should only apply to generators up to an appropriately defined capacity threshold, while beyond that threshold, generators would remain eligible for network support payments. In addition to the suggestion of a 10 MW threshold, there would be merit in considering whether a threshold of 30 MW (which corresponds to the present definition of 'scheduled generator') would be appropriate."[127]

EnergyAustralia supported all three options for change to the existing arrangements for TUoS rebates that were outlined in the Rule Proposal Report, including reaffirming its support for option 1 – that is, setting a maximum size threshold (which it proposed to be 10 MW) for the conferral of automatic TUoS rebates to embedded generators. EnergyAustralia reiterated its concern that the current arrangements could lead to unintended outcomes where the size of an embedded generator was close to matching local load. EnergyAustralia also suggested that the three options in the Rule Proposal Report were not mutual exclusive but complementary to its option 1.[128]

The NGF considered that the current TUoS rebate arrangements may be appropriate for smaller generators but for larger generators, there should be scope for calculating avoided TUoS payments based on savings in capital costs. In this context, the NGF highlighted a number of problems with the existing TUoS rebate regime. One problem was that due to different TUoS price structures in different jurisdictions, avoided TUoS savings were sometimes very small – for example, in South Australia, TUoS charges

---

[127] ENTOF, 25 September 2006, p.21.

[128] EnergyAustralia, 26 September 2006, p.20.

are based largely on fixed capacity rather than throughput. Another issue was that avoided TUoS was paid by DNSPs but notionally reflected capital savings to TNSPs. Therefore, the NGF suggested that it could be appropriate for TUoS rebates to be included as part of TNSPs' capital bases and then earmarked and passed on by the DNSP. The third problem was that DNSPs did not have to pay TUoS rebates to generators connected to inset networks within the DNSP's network.[129]

The MEU also made the point that in many jurisdictions, there is little benefit available from TUoS rebates due to the charging regime TNSPs have in place. This problem arises because TNSPs can choose their own TUoS pricing structure.[130]

The NGF disagreed with the proposition that network support payments ought to be adjusted to reflect anticipated TUoS rebates on the basis that network support payments were essentially an alternative to relying on constrained-on generation directions. Deducting network support payments from avoided TUoS rebates (or vice versa) would discourage generators from entering network support agreements and instead relying on compensation flowing from constrained-on generation.[131]

Finally, the NGF disagreed that there should be a maximum or minimum thresholds for the provision of TUoS rebates.[132]

AGL supported the maintenance of a TUoS rebates for embedded generators due to the imbalance of bargaining power between the parties. However, AGL agreed that embedded generators should not be over-rewarded for their investment. Therefore, AGL supported an approach where embedded generators smaller than 5 MW capacity should receive an automatic TUoS rebate covering the 'full cost' of transmission while a more precise approach ought to apply to larger embedded generators, and this amount should be in addition to any network support payments.[133]

The Total Environment Centre disagreed with the Commission's Rule Proposal and suggested that the arrangements do not adequately reward demand-side and non-network options. The Total Environment Centre opposed implementation of a minimum threshold for eligibility for TUoS rebates and supported a review of TUoS rebates as soon as practicable.[134]

---

[129] National Generators Forum, 22 September 2006, pp.5-6.

[130] Major Energy Users, September 2006, pp.31-33.

[131] National Generators Forum, 22 September 2006, p.6.

[132] National Generators Forum, 22 September 2006, p.7.

[133] AGL, 26 September 2006, pp.1-2.

[134] Total Environment Centre, September 2006, p.5.

## 7.3 Draft Determination

The Commission believes that care must be taken to ensure that the Rules relating to TUoS rebates do not 'over-reward' embedded generators for their investments and also avoid discrimination in favour of embedded generation over demand side management and other such options. While embedded generators may defer transmission investment, so does an electricity consumer's willingness to reduce consumption at peak times.

The Commission believes that there are benefits in streamlining the TUoS rebates regime to prevent 'double-counting' of benefits and to promote negotiation rather than regulatory prescription. An improvement of this type could be achieved by ensuring that any network support payments to an embedded generator be reflected in the expected TUoS rebates they receive. An approach of this nature may help integrate the arrangements for TUoS rebates and network support arrangements and help level the playing field between embedded generation, demand side management and other alternatives to transmission augmentation.

The Commission notes, however, that most of the network support arrangements pertaining to embedded generators are with DNSPs rather than TNSPs. Therefore, while the Commission could implement an approach to amend the network support pass through provisions for TNSPs such that they require the pass through amount to be net of TUoS rebates, it is unlikely that this amendment would have any great effect in practice. In addition, there are likely to be additional problems for TNSPs such as determining the amount of TUoS rebates paid by the DNSP to the embedded generator. Therefore, the Commission considers that this issue would be best addressed through changes to the Rules that govern the relationship between distributors and embedded generators.

In addition to the problem of 'double-counting' the Commission believes that there is some benefit in ensuring that the regime for TUoS rebates is delivering the most efficient outcomes for network utilisation. The rationale for the TUoS rebate regime is that by locating where they do, embedded generators reduce the 'net load' drawing off a transmission connection point and may therefore help avoid the need for future regulated transmission investment to support load growth at that location. The Rules and Regulatory Test currently provide for payments to embedded generators to be included in a TNSP's allowable regulated revenue where the embedded generator is the most net beneficial (or least cost) option available for serving load (see clauses 6.2.4(c)(7) and 5.6.2(m)). This suggest that ideally, TUoS rebates should only be available to embedded generators where they represent the *best* option for meeting load (reliability or market benefit) requirements. Unless an embedded generator represents the best option, automatic TUoS rebates may effectively involve the subsidisation (at consumer expense) of a sub-optimal option for meeting load requirements. However, on the other hand it is also recognised that for smaller embedded generators:

- transactions costs of participating in a Regulatory Test consultation and assessment processes may inefficiently deter proponents of small embedded generators from putting forward their proposals to TNSPs for eligibility for network support payments; and

- individually, smaller embedded generators may be too small to defer or avoid the need for an actual future regulated transmission augmentation, but collectively, they may be able to do so.

Based on this there may be some benefit in establishing a threshold above which an embedded generator would need to demonstrate that it provides benefits in support of the network. In this circumstance larger generators would not necessarily receive an automatic TUoS rebates, but would offer themselves to TNSPs or DNSPs as providing efficient non-network options for addressing congestion or meeting NSPs' reliability obligations in return for network support payments.

The Commission has formed the view that a comprehensive change to the regime for embedded generators is not within the scope of the transmission pricing rules. However, the Commission does believe that this is a matter that participants and policy makers should consider further to decide it there are benefits in advancing a comprehensive solution through a Rule change proposal. The Commission intends to bring these issues to the attention of the MCE in the context of its current review of the distribution network rules.

# 8 Inter-regional TUoS

The current Rules allow TNSPs in regions that import electricity, to receive inter-regional settlement residues (IRSRs) attributed to regulated interconnectors (clause 3.6.5(a)(5)). These amounts must be used by the importing region TNSP to reduce the Customer TUoS General Charge payable by its customers. In return, TNSPs in importing regions are required to pay a negotiated charge to the exporting region's TNSP that reflects the use of the exporting TNSP's network in effectively contributing to the creation of these residues (and benefits to the importing region). Clause 3.6.5(a)(5) of the existing Rules provide for the negotiation of these inter-regional TUoS payments to be undertaken by the respective jurisdictional governments. However, in practice only Victoria and South Australia have negotiated inter-regional TUoS payments.[135]

Subsequent to the release of the Issues Paper, the Commission received a Rule change request from the Victorian Department of Infrastructure, which among other matters sought to extend clause 3.6.5(a)(5)(i) until 1 July 2009. The Rule change was approved by the Commission and came into effect on 13 July 2006.[136]

Overall, the current Rules do not prevent a TNSP from recovering the costs of transmission interconnector investments. However, apart from the Victorian and South Australia case, TNSP's present practice is to recover the costs of such investments solely from their own customers.

## 8.1 Approach in the Proposed Pricing Rule

The Commission considered that an effective NEM-wide regime that provides for appropriate payments between TNSPs may be a necessary component of the regulatory framework for transmission pricing. However, because relatively few stakeholders commented on this issue in submissions on the Pricing Issues Paper. The Commission again invites stakeholder comment on possible options for inter-regional TUoS, to provide a basis for preparing a Draft Rule on this issue.

Recognising the inter-jurisdictional nature of this issue and the views of submitters that the MCE should be consulted, the Commission proposes to consult with the MCE regarding its view on the options for addressing this matter.

## 8.2 Submissions on the Proposed Pricing Rule

ETNOF reiterated their earlier submission on the Issues Paper that inter-regional TUoS arrangements are a matter on which MCE guidance should be obtained.[137]

The NGF also believed that a policy direction from the MCE be sought before any changes are considered. However, the NGF did suggest that the (current) use of

---

[135] ESCOSA, Settlement Residue Auctions and Network rebates, April 2002, p.4

[136] AEMC, Extension of the Inter-regional Settlements Agreement, Final Determination, 13 July 2006.

[137] ETNOF, 25 September 2006, pp.21.

settlement residue auction proceeds as a payment between jurisdictions is inadequate.[138]

EnergyAustralia agreed with the objective of a national transmission pricing regime but highlighted the importance of having appropriate transitional arrangements in place if such a change were undertaken.[139]

AGL repeated the views expressed in its earlier submissions that the use of IRSR payments as a 'surrogate' for inter-regional TUoS transfers should lapse and be replaced by a robust method for charging for interstate networks (p.2). AGL supported a simple methodology such as either the approach proposed by NECA as part of the Transmission and Distribution Pricing Review or an approach where flows between regions are treated as a load or generator at the region boundary. Whether a region is a net load or generator should be determined over the peak twelve days for that region. The amount recovered from other regions in this way should be subtracted from the AARR to be recovered from the region in question.[140]

The MEU contended that it would be insufficient for the Commission to simply refer this matter to the MCE without setting out what approach the Commission considers appropriate to resolve this issue in a way that promotes economic efficiency.[141]

## 8.3 Draft Determination

The Commission accepts the view expressed in submissions that inter-regional TUoS arrangements are a policy matter that requires input from the jurisdictions and notes that the ERIG is likely to consider this issue as part of its work on transmission. The Commission has therefore not proposed any Rule changes on inter-regional TUoS arrangements in the present Review.

However, the Commission notes that several stakeholders have pointed out that the current arrangements are inadequate and are subject to a sunset provision (which has been extended more than once) (Clause 3.6.5). The arrangements are based on negotiation between jurisdictions, rather than between TNSPs, and the Commission notes that this may only have occurred between Victoria and South Australia. Therefore, the Commission considers it worthwhile to make some observations on the key ways in which the inter-regional TUoS issue could be addressed in a future review of the arrangements.

In keeping with the causer pays approach to prescribed transmission service cost allocation, the Commission considers that those consumers whose demand or consumption leads to costs being incurred ought to be charged a price that seeks to reflect the LRMC of their decisions. Within a TNSP's region, this signal is provided through the use of the CRNP or modified CRNP allocation methodologies combined with demand or peak/shoulder consumption-based price structures. However, under

---

[138] National Generators Forum, 22 September 2006, p.7.

[139] EnergyAustralia, 26 September 2006, p.21.

[140] AGL, 26 September 2006, p.2.

[141] Major Energy Users, September 2006, p.34.

the current arrangements, consumers in a (net) importing region do not pay a charge that reflects any of the transmission costs incurred in the relevant exporting region to serve their load. This means that the locational charge (ie the Customer TUoS Usage charge) levied on consumers in the importing region is likely to be less indicative of the full LRMC of their transmission service. It also means that the cost of these inter-regional services are fully reflected and recovered in the TUoS charges levied on customers in the exporting region such that these locational charges which are likely to exceed the full LRMC of the services as a result.

Under the current arrangements, as noted in chapter 4, IRSR auction proceeds are returned to customers in the importing region through lower transmission charges. The IRSR auction proceeds are primarily used to reduce transmission charges related to the cost of interconnector assets in the importing region. This benefits consumers located on or near interconnectors as they would be allocated a significant share of the interconnector cost. However, the effect also flows through to all consumers in an importing region, thereby reducing all of their TUoS charges to some extent. The result is lower delivered energy prices (wholesale electricity plus transmission charges) to consumers in importing regions than would otherwise be the case.

This means that, other things being equal, a new 'footloose' load considering whether to locate in an exporting or importing region currently receives only a muted price signal to locate in the exporting region – this being the region experiencing relatively less scarce supply conditions. The Commission believes that while the magnitude of this impact may be limited, it is a situation that should be remedied and a simple and workable, if imperfect, solution could be developed relatively easily.

In this context, the Commission's considers that any of the final three options as outlined above in the Rule Proposal are worthy of more detailed examination. These were:

- adopting a simplified 'rule of thumb' such as splitting the IRSR equally between the exporting and importing regions to (partially) recognise the benefit the importing region's network users gain from the exporting TNSP's network;

- implementing an inter-regional TUoS pricing arrangement by obliging TNSPs to apply the Customer TUoS Usage Charge to interconnectors. The TNSP in each importing region would pay this charge to the TNSP in the exporting regions and would recover the cost through an addition to the TUoS General charge; and

- undertaking a full NEM-wide cost allocation exercise for inter-regional TUoS pricing arrangements.

The advantage of the final option is that the locational TUoS charge paid by a consumer would reflect its notional usage of *all* transmission network assets in the NEM based on the CRNP (or substitute) allocation methodology. However, the Commission considers that the final option is unlikely to be practicable in the short term and would require collaboration between all TNSPs as well as for all TNSPs to apply a similar cost allocation methodology. This would also negate the benefits cited earlier of different TNSPs applying different approaches to suit local conditions on their networks.

By contrast, the Commission considers that either the simplified rule of thumb approach or the levying of Customer TUoS Usage charges on interconnectors should be able to be implemented in the year following a decision in favour of the option. Both of these options would not provide as clear locational and time-of-use signals as under the NEM-wide cost allocation approach. This is because under either of the alternative approaches, the deemed use of an exporting region's network by an importing region's consumer would be reflected in that consumer's non-locational postage-stamped (TUoS General) charge rather than its locational (TUoS Usage) charge. Indeed, it was this concern that lay behind the ACCC's objection to the second of these approaches in 2001. Further, the Commission notes that the allocation under the second option could be contentious where TNSPs had different cost allocation methodologies. However adopting this approach even with this flaw still would be likely to lead to an improvement on the current situation.

Recognising the complexity of this issue as well as its inter-jurisdictional nature, the Commission considers that these issues are best dealt with outside this review of transmission pricing. Therefore, the Commission will write to the MCE expressing this view and the need for a further review of these issues.

# 9 Pricing for negotiated transmission services

The Commission, in the review of the transmission revenue and pricing Rules, has sought to clarify the delineation of services provided by TNSPs. The Draft Revenue Rule adopts two classifications for transmission services - Prescribed Transmission Services and Negotiated Transmission Services. The Commission's Draft Revenue Determination establishes a revenue cap form of regulation for Prescribed Transmission Services. For Negotiated Transmission Services, the Commission has created a commercial negotiation framework that is supported by an effective dispute resolution regime under which disputes in relation to price are decided by a commercial arbitrator.[142]

More specifically, the Draft Revenue Rules provides for the following in relation to Negotiated Transmission Services:

- pricing principles for negotiated services, which guide the AER in specifying pricing criteria for a TNSP;
- the pricing criteria to be applied by a TNSP in negotiating (and by a commercial arbitrator in resolving disputes about) the prices that are to be charged for provision of negotiated services and access charges;
- the requirements for the preparation of a negotiating framework (equivalent to the existing clause 6.5.9);
- referral of a dispute to a commercial arbitrator who may make a determination that is binding on the TNSP and on the Applicant for services; so that failure to comply with its terms is a breach of the Rules;[143] and
- the commercial arbitrator is a "dispute resolution panel" under the NEL, and this means that the procedures under the uniform Commercial Arbitration Acts of the participating jurisdictions are available for appeals on questions of law[144]

Therefore, to the extent that actual or potential network users seek to procure and/or TNSPs seek to provide, transmission services that fall outside the definition of Prescribed Transmission Service, the arrangements specified in the Draft Revenue Rule would, if accepted, be applicable. On this basis, the Commission does not consider that it is necessary for the Rules to provide pricing criteria for Negotiated Transmission Services.

However, in the Proposed Rule Report the Commission did seek comment regarding whether the model for commercial dispute resolution for price for Negotiated Transmission Services should be extended to permit consideration of the terms and conditions of the connection agreements under which those prices are charged, and to

---

142 See Draft Revenue Rule, Part D.

143 The Draft Revenue Rule expressly excludes a dispute under clause 6A.9.8 from the Chapter 8 dispute resolution regime.

144 See sections 58 & 71 of the NEL.

which the price is inextricable linked. The remainder of this chapter considers this issue further.

## 9.1 Submissions on the Proposed Pricing Rule

The MEU and EnergyAustralia contended that a negotiation approach for transmission services is only appropriate for the largest customers. In many cases, the TNSP will have greater bargaining power than the connecting party because there is no practicable alternative network to which the party can connect. Both submitters also stated that they supported the Commission's proposal that commercial arbitration and dispute resolution under Chapter 6 encompasses aspects other than price, with necessary changes to be made to Chapter 5.[145] With respect to the appointment of persons to adjudicate disputes, EnergyAustralia suggested that Schedule 6.3A should adopt a similar process as under Chapter 8 of the Rules to ensure persons of appropriate skills are appointed. EnergyAustralia also suggested that the Commission consult on appropriate criteria for the resolution of disputes involving terms and conditions other than price.[146]

The NGF commented that where there is a clear absence of competitive services available, a strong regulatory framework is required. The NGF thus supported additional pricing rules that would ensure the generator and the TNSP could negotiate over a transmission service on an equal footing.[147]

AGL contended that commercially negotiated contracts were preferable to regulated arrangements even where there was an obvious imbalance of power between a TNSP and its customer. AGL agreed that the Rules should provide for commercial arbitration where negotiation failed but that the Rules should also require TNSPs to submit terms and conditions along with any price to a requesting party.[148]

## 9.2 Draft Determination

The Commission acknowledges that submissions generally supported the extension of the commercial dispute resolution model for the price of Negotiated Transmission Services to permit consideration of the terms and conditions of the connection agreements under which those prices are charged.

The Commission notes that the regime for negotiated transmission services only applies to generators and loads directly connected to a transmission network. In this Commission's view, this suggests that the parties to a negotiation process with a TNSP are likely to be relatively large and commercially-aware entities. These parties would presumably need to negotiate with a range of other supplier and customer counterparties regarding other aspects of their business. While there may be an inequality of bargaining power between a transmission customer and the TNSP, the

---

[145] Major Energy Users, September 2006, p.36; and EnergyAustralia, 26 September 2006, p.22.

[146] EnergyAustralia, 26 September 2006, pp.22-23.

[147] National Generators Forum, 22 September 2006, p.3.

[148] AGL, 26 September 2006, p.3.

regime is designed to provide a means of redressing these inequalities through pricing criteria, information provision obligations and commercial arbitration.

Therefore, on this basis, the Commission has decided not to proceed with a further extension of the commercial arbitration regime to the terms and conditions of the agreement at this time.

## Appendix 1: Schedule 1 to NEL items 15-24

15 The regulation of revenues earned or that may be earned by owners, controllers or operators of transmission systems from the provision by them of services that are the subject of a transmission determination.

16 The regulation of prices charged or that may be charged by owners, controllers or operators of transmissions 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.

17 Principles to be applied, and procedure to be followed, by the AER exercising or performing an AER economic regulatory function power.

18 The assessment, or treatment by the AER, of investment in transmission systems for the purposes of making a transmission determination.

19 The economic framework and methodologies to be applied by the AER for the purposes of item 18.

20 The mechanisms or methodologies for the derivation of the maximum allowable revenue or prices to be applied by the AER in making a transmission determination.

21 The valuation, for the purposes of making a transmission determination, of assets forming part of a transmission system owned, controlled or operated by a regulated transmission system operator, and of proposed new assets to form part of a transmission system owned, controlled or operated by a regulated transmission system operator, that are, or are to be, used in the provision of services that are the subject of a transmission determination.

22 The determination by the AER, for the purpose of making a transmission determination with respect to services that are the subject of such a determination, of:

a. a depreciation allowance for a regulated transmission system operator; and

b. operating costs of a regulated transmission system operator; and

c. an allowable rate of return on assets forming part of a transmission system owned, controlled or operated by a regulated transmission system operator.

23 Incentives for regulated transmission system operators to make efficient operating and investment decisions.

24 The procedure for the making of a transmission determination by the AER, including

a. the publication of notices by the AER; and

b. the making of submissions, including by the regulated transmission system operator to whom the transmission will apply and by affected Registered participants (within the meaning of section 16 (3); and

c. the publication of draft and final determinations and the giving of reasons: and

d. the holding of pre-determined conferences.

# Appendix 2: List of Submissions

AGL

Alcoa

Australian Energy Regulator

Electricity Transmission Network Owners Forum

Energy Action Group

Energy Retailers Association of Australia

EnergyAustralia

Hydro Tasmania

Institute of Public Affairs

Integral Energy

InterGen

Major Energy Users Inc and Major Employers Group of Tasmania

National Generators Forum

Public Interest Advocacy Centre

Queensland Rail

Total Environment Centre

VENCorp

## Appendix 3: Timeline

**Scoping Paper**

Released: 29 July 2005

**Revenue Requirements**

**Issues Paper**

**Rule Change Process**

Rule Proposal (s.95 notice): 16 February 2006

Public Hearing: 8 March 2006

Submissions due: 20 March 2006

Draft Determination: 27 July 2006

Submissions: 11 September 2006

Final Determination: October 2006

**Rules Commence**

**Pricing**

**Issues Paper**

**Rule Change Process**

Rule Proposal (s.95 notice): 24 August 2006

Submissions: 25 September 2006

Draft Determination: October 2006

Submissions: November 2006

Final Determination: December 2006

**Rules Commence**

January 2007